ROCIS for the Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

3/15/2023

Category	Primary Estimate	Estimates Low Estimate	High Estimate	Year Dollar	Units Discount Rate	Period Covered	Notes
Benefits							
Annualized Monetized ($millions/year)	$6,900.00			2019	7%	2024-2042	These benefit estimates are of the illustrative proposal scenario representing the proposed NSPS and proposed Emissions Guidelines together, relative to the baseline. They reflect climate impacts from CO2 emission changes and do not account for changes in non-CO2 GHG emissions. In addition, they also reflect air quality health benefits from reduced exposure to PM2.5 and ozone associated with emission reductions of directly emitted PM2.5, SO2, and NOX. The estimates are the Equivalent Annualized Value of the monetized benefits over the 2024-2042 period, discounted to 2024 using a 3% discount rate for climate benefits in both cases.
	$7,500.00			2019	3%	2024-2042	
Annualized Quantified					7%		
					3%		
Qualitative							Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits
Costs							
Annualized Monetized ($millions/year)	$980.00			2019	7%	2024-2042	These compliance costs estimates are approximated by the illustrative proposal scenario representing the proposed NSPS and proposed Emissions Guidelines together, using the Integrated Planning Model. These costs include an estimate of value of monitoring, recordkeeping, and reporting costs. The estimates are the Equivalent Annualized Value of the costs over the 2024-2042 period.
	$950.00			2019	3%	2024-2042	
Annualized Quantified					7%		
					3%		
Qualitative							
Transfers							
Federal Annualized Monetized ($millions/year)					7%		
					3%		Not Applicable
From/To	From:			To:			
Other Annualized Monetized ($millions/year)					7%		
					3%		Not Applicable
From/To	From:			To:			

Category	Effects	
Effects		
State, Local, and/or Tribal Government	The proposed NSPS contain a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year.	
Small Business	These actions will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of the NSPS are private companies, investor-owned utilities, co-operatives, municipalities, and sub-divisions that would seek to build and operate stationary combustion turbines in the future. The Agency has determined that seven small entities may be impacted, and may experience an impact of 0 percent to 0.9 percent of revenues in 2035.	
Wages	No estimates available regarding changes in wages in the main RIA, but an appendix to the RIA provides a sensitivity analysis with information on potential economy-wide and sectoral labor demand impacts.	
Growth	We do not have any estimates regarding changes in economic growth associated with implementation of these proposed rules in the main RIA, but an appendix to the RIA provides a sensitivity analysis with information on potential economy-wide and sectoral growth impacts.	

Template for Accounting Statement for Economically Significant Rules (with calculations)

(provided by OMB on 02/06/09)

Category	Estimates: Primary Estimate	Low Estimate	High Estimate	Units: Year Dollar	Discount Rate	Period Covered	Notes
Benefits							
Annualized Monetized ($millions/year)	0.0	0.0	0.0		7%		
	0.0	0.0	0.0		3%		
Annualized Quantified	0.0	0.0	0.0		7%		
	0.0	0.0	0.0		3%		
Qualitative							
Costs							
Annualized Monetized ($millions/year)	0.0	0.0	0.0		7%		
	0.0	0.0	0.0		3%		
Annualized Quantified	0.0	0.0	0.0		7%		
	0.0	0.0	0.0		3%		
Qualitative							
Transfers							
Federal Annualized Monetized ($millions/year)	0.0	0.0	0.0		7%		
	0.0	0.0	0.0		3%		Enter the red cells into the ROCIS sheets
From/To	From:			To:			
Other Annualized Monetized ($millions/year)	0.0	0.0	0.0		7%		
	0.0	0.0	0.0		3%		
From/To	From:			To:			
Effects							
State, Local, and/or Tribal Government							
Small Business							
Wages							
Growth							

Exhibit 1. Respondent Burden and Cost of Reporting and Recordkeeping Requirements for States, Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units (40 CFR Part 60, Subpart UUUUb)

Burden Item	(A) Hours/ Occurrence	(B) Occurrences/ Respondent/Year	(C) Hours/ Respondent/Year (A x B)	(D) Respondents/ Year	(E) Total Hours/Year (C x D)	(F) Technical Hours/Year (E x 0.79)	(G) Managerial Hours/Year (E x 0.09)	(H) Clerical Hours/Year (E x 0.12)	(I) Cost/Year[a]
1. REPORTING REQUIREMENTS									
A. Read and Understand Rule Requirements	Incl. in 1B								
B. Required Activities									
Develop state plans[b,c]	6,240	1	6,240	15.3	95,680	75,587	8,611	11,482	$12,110,594
C. Create Information	Incl. in 1B								
D. Gather Information	Incl. in 1B								
E. Report Preparation									
Develop final plan	Incl. in 1B								
Negative declaration[d]		1	1	1.3	1	1	0	0	$169
AVERAGE ANNUAL LABOR BURDEN AND COST					**95,680**	**75,587**	**8,611**	**11,482**	**$12,110,762**
AVERAGE ANNUALIZED COSTS (O&M) (Reporting/recordkeeping supplies)									**$36,750**

[a] This ICR uses the following labor rates: $90.89 (technical), $100.15 (managerial), and $45.76 (clerical). The source is the U.S. Department of Labor, Bureau of Labor Statistics, Occupational Employment Statistics, May 2021 National Industry-Specific Occupational Employment and Wage Estimates, NAICS 999200 - State Government, excluding schools and hospitals (OES Designation) <https://www.bls.gov/oes/current/naics3_999200.htm> They have been increased by 110 percent to account for the benefit packages available to those employed by private industry.

[b]Burden based on 3 FTEs per state to develop, submit, and implement state plans.

[c]Respondents include 46 states not expected to have existing requirements similar to the emission guidelines, averaged over the 3-year ICR period (46/3=15.3).

[d]Respondents include the 4 states (ID, OR, RI, VT) expected to submit a one-time negative declaration, averaged over the 3-year ICR period (4/3=1.3).

Nationwide Respondent Assumptions

Respondents[a,b]	No.	Notes
Total no. respondents	50	50 states
Number of states expected to submit state plan	46	States expected to have existing EGUs during the 3-yr ICR period.
Number of states expected to submit negative declaration	4	ID, OR, RI, VT

[a] The estimate accounts for states expected to have regulations and programs in place

[b] Tribes expected to rely on federal plan.

287,040	hours for 3 years	$36,332,287
1,914	avg annual per respondent	$ 242,215

Respondent Labor Rates

Labor Category	Respondent Labor Rates (May 2021)		
	Unloaded	Overhead Multiplier (110%)	Loaded
States [a]			
Technical [Occupation code 17-2000]	$43.28	2.1	$90.89
Managerial [Occupation code 11-0000]	$47.69	2.1	$100.15
Clerical [Occupation code 43-0000]	$21.79	2.1	$45.76
Composite			$115.49

[a] Unloaded mean hourly wage from U.S. Department of Labor, Bureau of Labor Statistics, Occupational Employment Statistics, May 2021 National Industry-Specific Occupational Employment and Wage Estimates, NAICS 999200 - State Government, excluding schools and hospitals (OES Designation) <https://www.bls.gov/oes/current/naics3_999200.htm>

Recordkeeping/Reporting Supplies (Annual O&M Costs)[a]

Supply Item	Price per Item	Number per Respondent	Number of Respondents[b]	Total
File cabinet to store hard copy records	$235	1	50	$11,750
Miscellaneous annual supplies	$500	1	50	$25,000
Average Annual Cost				**$36,750**

[a] Costs based on estimates in the supporting statement for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units supporting statement (EPA-HQ-OAR-2017-0355-26731).

[b] Respondents include all 50 states.

Exhibit 2. Burden and Cost to the Agency, Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units (40 CFR Part 60, Subpa

Activity	(A) Hours/ Occurrence	(B) Occurrences/ Respondents/Year	(C) Hours/Respondent/Year (A x B)	(D) Respondents/ Year	(E) EPA Total Hours/Year (C x D)	(F) EPA Technical Hours/Year (E x 0.79)	(G) EPA Managerial Hours/Year (E x 0.09)	(H) EPA Clerical Hours/Year (E x 0.12)	(I) Cost, $
1. SUPPORT/OUTREACH									
EPA Headquarters									
States expected to submit a state plan [a]	136	1	136	46	6,240	4,930	562	749	$451,348
EPA Regions [b]	21	1	21	46	957	756	86	115	$59,487
2. REPORT REVIEW [c]									
Review negative declarations [d]	1	1	1	1.3	1.33	1.05	0.12	0.16	$83
Coordination on submitting state plans [e]	160	1	160	15.3	2,453	1,938	221	294	$177,453
Review notifications of public hearings on plans [f]	2	1	2	15.3	31	24	3	4	$2,218
Review certifications that public hearings on plans conducted according to subpart Ba procedures [f]	2	1	2	15.3	31	24	3	4	$2,218
Review/approve plans									
Other States[g]	1,040	1	1,040	15.3	15,947	12,598	1,435	1,914	$991,451
AVERAGE ANNUAL LABOR BURDEN AND COST					**25,659**	**20,271**	**2,309**	**3,079**	**$1,684,258**
AVERAGE ANNUAL OTHER DIRECT COSTS									
Miscellaneous cost (*e.g.,* telephone, photocopies, postage)									**$1,000**
TOTAL AVERAGE ANNUAL COST (Average Annual Labor Cost + Average Annual Other Direct Costs)									**$1,685,258**

[a] Assumes 3 FTEs per year to oversee the entire program and help with outreach/state/enforceability questions and regional assistance, divided by the total number of respondents.

[b] Assumes 2 hours per week of outreach per EPA Region, divided by the total number of respondents.

[c] One-time activities, averaged over the 3-year ICR period.

[d] Respondents include the 4 states (ID, OR, RI, VT) expected to submit a one-time negative declaration, averaged over the 3-year ICR period (4/3=1.3).

[e] Assumes 4 weeks to coordinate with states to advise on their development of state plans and extension requests; respondents include 46 states, averaged over the 3-year ICR period (46/3=15.3).

[f] Includes all 46 states for which a state plan was developed, averaged over the 3-year ICR period (46/3=15.3).

[g] Assumes 6 full months for EPA Regions to review each state plan, with some coordination with EPA Headquarters; averaged over the 3-year period (46/3=15.3)

EPA Staff Labor Rates

Labor Category	Labor Rates (2023)		
	Unloaded[a]	Overhead Multiplier (60%)	Loaded
EPA Headquarters			
Technical (Grade 13, Step 5)	$45.91	1.6	$73.46
Managerial (Grade 15, Step 5)	$63.82	1.6	$102.11
Clerical (Grade 9, Step 5)	$26.62	1.6	$42.59
EPA Regions			
Technical (Grade 12, Step 5)	$38.61	1.6	$61.78
Managerial (Grade 15, Step 5)	$63.82	1.6	$102.11
Clerical (Grade 7, Step 5)	$21.77	1.6	$34.83

[a] Unloaded labor rates from U.S. Office of Personnel Management <https://www.opm.gov/policy-data-oversight/pay-leave/salaries-wages/salary-tables/pdf/2023/GS_h.pdf>

Other Direct Costs

Expense Item	Cost
Miscellaneous cost (*e.g.,* telephone, photocopies, postage)	$1,000

[a] Costs based on estimates in the supporting statement for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units supporting statement (EPA-HQ-OAR-2013-0602-36879).

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

APPLICABILITY

§60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit and integrated gasification combined cycle facility (IGCC) that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**], or commence reconstruction after June 18, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**]. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that commenced construction after January 8, 2014 or commenced modification or reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction after June 18, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER** or commence reconstruction after June 18, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**] that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (9) of this section.

(1) Your EGU is a steam generating unit or IGCC that annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-

electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline).

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

EMISSION STANDARDS

§60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§60.5520 What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in Table 2 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

GENERAL COMPLIANCE REQUIREMENTS

§60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under §60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 or 2 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with §60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under §60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2\ emissions\ standard\ = \frac{\left(50 \text{ x } HTIP_{ng}\right) + \left(69 \text{ x } HTIP_O\right)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in §72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in §72.2 of this chapter) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under §75.64(a) of this chapter has passed prior to October 23, 2015, emissions reporting shall begin according to §60.5555(c)(3)(i) (for Acid Rain program units), or according to §60.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under §75.64(a) of this chapter occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under §60.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under §60.5555(c)(3)(iii).

MONITORING AND COMPLIANCE DETERMINATION PROCEDURES

§60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under §60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under §60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in §75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see §60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to §75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.*, carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with §75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to §75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from §75.11(b) or submit a petition to the Administrator under §75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in §60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in §60.5520(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(3) For each “valid operating hour” (as defined in §60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under §60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under §98.33(a)(3) of this chapter.

(d) Consistent with §60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and

operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see §60.17). For a combined heat and power (CHP) EGU, as defined in §60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.*, lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under §60.5520(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under §60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under §98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of part 98 of this chapter. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to part 75 of this chapter.

(e) Consistent with §60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in Table 1 or 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as "stack operating hours" (as defined in

§72.2 of this chapter). If you attain compliance with the applicable emissions standard in §60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternate, or if the EGUs are subject to different emission standards in Table 1 or 2 of this subpart, you must either (1) monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or (2) apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§60.13(g) and 60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the "stack operating time" (as defined in §72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with §60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in §60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under §60.5535(b) or (c), as applicable, and either the generating load data from §60.5535(d)(1) for output-based calculations or the heat input data from §60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.*, operating hours for which:

(i) "Valid data" (as defined in §60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input;

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable; or

'(iv) Grace periods for delaying RATAs for any of the parameters used to determine the hourly carbon dioxide mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from §60.5535 for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with §60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{\mathrm{TDF}} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with §60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in §60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg ((lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based

standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with §60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under §60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with §60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 or 2 of this part, or the emissions standard calculated in accordance with §60.5525(a)(2).

NOTIFICATION, REPORTS, AND RECORDS

§60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 of this subpart).

(b) You must prepare and submit notifications specified in §75.61 of this chapter, as applicable, to your affected EGUs.

§60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by §60.5525 to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the

affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in §60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.*, the total number of valid operating hours (as defined in §60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with §60.5520, the CO_2 emissions standard (as identified in Table 1 or 2 of this part) with which your affected EGU must comply; and

(vi) Consistent with §60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with §60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a) of this chapter, *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under §75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under §75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with §75.4(j) of this chapter, §75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in §60.5540(a)(1)), and shall not be used in the compliance determinations under §60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under §72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under §72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under §72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in §60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under §75.53(g) and (h) of this chapter;

(ii) Operating parameter records under §75.57(b)(1) through (4) of this chapter;

(iii) The records under §75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under §75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under §75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under §75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under §75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under §75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with §60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

§60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

OTHER REQUIREMENTS AND INFORMATION

§60.5570 What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under §60.8(b).

§60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.*, solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388-99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit*, *(*also known as “cogeneration”) means a steam generating unit, IGCC, or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.*, electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.*, CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17), ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see §60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396-98 (incorporated by reference, see §60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975-08a (incorporated by reference, see §60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see §60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see §60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see §60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.*, meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that result from a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (*e.g.*, CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or 2 of this subpart.

Table 1 of Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction After January 8, 2014 and Reconstruction or Modification After June 18, 2014

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	**CO_2 Emission standard**
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC)	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh).

Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h)	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than:
	1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h; or
	2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

Table 2 of Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014 and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	**CO_2 Emission standard**
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis]	50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input.

Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in §60.5525.

Table 3 to Subpart TTTT of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580.
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	No	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§60.8(c) – (f)	Conducting performance tests	No	
§60.9	Availability of Information	Yes	

§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13 (a) – (h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Stationary Combustion Turbine Electric Generating Units

APPLICABILITY

§60.5508a What is the purpose of this subpart?

This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**],

§60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any stationary combustion turbine that commenced construction or reconstruction after [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER].**

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (9) of this section.

(1) [RESERVED]

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each stationary combustion turbine) is 25 MW or less.

(5) [RESERVED]

(6) [RESERVED]

(7) [RESERVED]

(8) [RESERVED]

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

EMISSION STANDARDS

§60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

§60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term “gross or net energy output” is used, the term that applies to you is “gross energy output.”

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in Table 1 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in Table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, low-GHG hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under §60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section. Any combustion turbine burning hydrogen fuel for compliance purposes must co-fire 30 percent by volume low-GHG hydrogen.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with §60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using

one of the methods under §60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2\ emissions\ standard\ = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating or less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 350 kg CO_2/MWh-gross (770 lb CO_2/MWh-gross) or 360 kg CO_2/MWh-net (790 lb CO_2/MWh-net); 40 kg CO_2/MWh-gross (90 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); or 310 kg CO_2/MWh-gross (680 lb CO_2/MWh-gross) or 320 kg CO_2/MWh-net (700 lb CO_2/MWh-net) as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h) (410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net))

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

$$CO_2\ emissions\ standard\ = \text{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in §72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) [RESERVED]

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580a) after the calendar month in which emissions reporting is required to begin under §60.5555a(c)(3)(iii).

MONITORING AND COMPLIANCE DETERMINATION PROCEDURES

§60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under §60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under §60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in §75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see §60.5555a(c)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) [RESERVED]

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in §60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in §60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(3) For each “valid operating hour” (as defined in §60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under §60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under §98.33(a)(3) of this chapter.

(d) Consistent with §60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see §60.17). For a combined heat and power (CHP) EGU, as defined in §60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.*, lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under §60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under §60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under §98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of part 98 of this chapter. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to part 75 of this chapter.

(e) Consistent with §60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in Table 1 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected

EGUs and you must express the operating time as “stack operating hours” (as defined in §72.2 of this chapter). If you attain compliance with the applicable emissions standard in §60.5520a at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternate, or if the EGUs are subject to different emission standards in Table 1 of this subpart, you must either (1) monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or (2) apportion the CO_2 mass emissions based on the unit’s load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in §72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with §60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in §60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under §60.5535a(b) or (c), as applicable, and either the generating load data from §60.5535a(d)(1) for output-based calculations or the heat input data from §60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only “valid operating hours” in the compliance period, *i.e.*, operating hours for which:

(i) “Valid data” (as defined in §60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input;

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable; or

(iv) Grace periods for delaying RATAs for any of the parameters used to determine the hourly carbon dioxide mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from §60.5535a for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with §60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with §60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in §60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg ((lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based

standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with §60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under §60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with §60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 of this part, or the emissions standard calculated in accordance with §60.5525a(a)(2).

NOTIFICATION, REPORTS, AND RECORDS

§60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 of this subpart).

(b) You must prepare and submit notifications specified in §75.61 of this chapter, as applicable, to your affected EGUs.

§60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by §60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic

quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in §60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.*, the total number of valid operating hours (as defined in §60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with §60.5520a, the CO_2 emissions standard (as identified in Table of this part) with which your affected EGU must comply; and

(vi) Consistent with §60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with §60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a) of this chapter, *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under §75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under §75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with §75.4(j) of this chapter, §75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not “valid operating hours” (as defined in §60.5540(a)(1)), and shall not be used in the compliance determinations under §60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under §72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under §72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under §72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in §60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under §75.53(g) and (h) of this chapter;

(ii) Operating parameter records under §75.57(b)(1) through (4) of this chapter;

(iii) The records under §75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under §75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under §75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under §75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under §75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under §75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with §60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

§60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

OTHER REQUIREMENTS AND INFORMATION

§60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under §60.8(b).

§60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.*, solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388-99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as "cogeneration") means a stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17), ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see §60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396-98 (incorporated by reference, see §60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975-08a (incorporated by reference, see §60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see §60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see §60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see §60.17).

Electric Generating units or EGU means any stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps, that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low-GHG Hydrogen means hydrogen (or a hydrogen derived fuel such as ammonia) produced through a process that results in a well-to-gate GHG emission rate of less than 0.45 kilograms of CO2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H_2), determining using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model).

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.*, the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that result from a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.*, CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1of this subpart.

Table 1 of Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After [INSERT DATE OF PUBLICATION] (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	**CO_2 Emission standard**
Newly constructed or reconstructed stationary combustion turbine that: • Supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis	For 12-operating month averages beginning before January 2035, 350 to 540 kg CO_2/MWh (770 to 1,200 lb CO_2/MWh) of gross energy output; or 360 to 550 kg CO_2/MWh (790 to

• Does not co-fire 10 percent or more hydrogen	1,220 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525. For 12-operating month averages beginning after December 2034, 40 to 60 kg CO_2/MWh (90 to 130 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525.
Newly constructed or reconstructed stationary combustion turbine that: • Supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis • Co-fire 10 percent or more hydrogen	For 12-operating month averages beginning before January 2035, 350 to 540 kg CO_2/MWh (770 to 1,200 lb CO_2/MWh) of gross energy output; or 360 to 550 kg CO_2/MWh (790 to 1,220 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525. For 12-operating month averages beginning after December 2034, 310 to 480 kg CO_2/MWh (680 to 1,100 lb CO_2/MWh) of gross energy output; or 320 to 480 kg CO_2/MWh (700 to 1,070 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525
Newly constructed or reconstructed stationary combustion turbine that supplies greater than 20% of its potential electric output and its design efficiency times its potential electric output or less as net-electric sales on both a 12-operating month and a 3-year rolling average basis	For 12-operating month averages beginning before January 2035, 520 to 700 kg CO_2/MWh (1,150 to 1,530 lb CO_2/MWh) of gross energy output; or 530 to 690 kg CO_2/MWh (1,160 to 1,550 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525. For 12-operating month averages beginning before January 2035, 450 to 590 kg CO_2/MWh (1,000 to 1,290 lb CO_2/MWh) of gross energy output; or 460 to 600 kg CO_2/MWh (1,010 to 1,300 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525.
Newly constructed or reconstructed stationary combustion turbine that supplies 20% or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in §60.5525.

Table 2 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	**Subject of citation**	**Applies to subpart TTTTa**	**Explanation**
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580a.
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	No	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§60.8(c) – (f)	Conducting performance tests	No	
§60.9	Availability of Information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	

§60.13 (a) – (h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

Subpart UUUUa—Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units [Removed]

■ 2. Remove subpart UUUUa.

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Introduction

§ 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish emission standards limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

§ 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of § 51.166(b)(49)(ii), with respect to GHG emissions from facilities regulated in the plan, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2, with respect to GHG emissions from facilities regulated in the plan, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in § 71.2 of this chapter.

§ 60.5710b Am I affected by this subpart?

If you are the Governor of a State in the United States with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the United States with no affected EGUs for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715b What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27a except that under § 60.27a(b) the Administrator will have 12 months after the date the final plan or plan revision (as allowed under § 60.5785b) is submitted, to approve or disapprove such plan or revision or each portion thereof.

§ 60.5720b What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved State plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a State plan.

§ 60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan submittal or a negative declaration letter (if applicable).

§ 60.5730b Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the Federal Register**.** If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your State, you will be found to have failed to submit a State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5740b What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (7) of this section in your plan submittal. The final plan must meet the requirements and include the information required under § 60.5745b.

> (1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. In addition, you must include an inventory of CO_2 emissions from the affected EGUs.

(2) *Standards of Performance.* You must include an identification of all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance (CO_2 lb/MWh-gross) that does not exceed the level calculated through the use of the methods described in § 60.5775b(c), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(i) States carry the burden of making the demonstrations required under the RULOF mechanism described in § 60.5775b(e) and have the obligation to justify any accounting for RULOF in support of less stringent standards of performance. The EPA may find that a state plan's demonstration is a basis for concluding that the plan is not "satisfactory" and may disapprove the plan on the basis that a State has not carried its burden in providing a less stringent standard based on RULOF.

(ii) States seeking to apply a more stringent standard of performance must adequately demonstrate that the standard is in fact more stringent. However, the state is not required to conduct a source-specific BSER evaluation for the purpose of applying a more stringent standard of performance, so long as the standard will achieve equivalent or better emission reductions. As for all standards of performance, the state plan must include requirements that provide for the implementation and enforcement of a more stringent standard.

(3) *Increments of Progress.* State plans must include specified enforceable increments of progress as required elements for affected EGUs within the subcategories of long-term existing coal-fired steam generating units (§ 60.5775b(b)(1)) and medium-term existing coal-fired steam generating units (§ 60.5775b(b)(2)), as follows:

(i) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan.
   - (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.
   - (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or FEED study.

(ii) Awarding of contracts. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded.
   - (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.
   - (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(iii) Initiation of on-site construction or installation of emission control equipment or process change.
   - (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.
   - (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, initiation of onsite construction or installation of emission

control equipment or process change required to achieve 90 percent CCS on an annual basis.

(iv) Completion of on-site construction or installation of emission control equipment or process change.

(A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(B) For affected units within the long-term existing coal-fired steam generating unit subcategory, completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CCS on an annual basis.

(v) A demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.

(A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, this increment of progress describes affected EGUs that adopt co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.

(B) For affected units within the long-term existing coal-fired steam generating unit subcategory, this increment of progress describes affected EGUs that adopt CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.

(vi) For affected units within the long-term existing coal-fired steam generating unit subcategory only, a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

(vii) Final compliance with the standard of performance by January 1, 2030.

(4) *Milestones for Federally Enforceable Commitment to Cease Operations.* State plans must include legally enforceable milestones for affected EGUs within the subcategories of imminent-term existing coal-fired steam generating units (§ 60.5775b(b)(4)), near-term existing coal-fired steam generating units (§ 60.5775b(b)(3)), and medium-term coal-fired steam generating unit (§ 60.5775b(b)(2)) subcategories, as follows:

(i) Five years before the date used to determine the applicable subcategory under these emission guidelines (the date that the affected EGU permanently ceases operations) or 60 days after state plan submission, whichever is later, designated facilities must submit a Milestone Report to the applicable State administering authority that includes the following:

(A) A summary of the process steps required for the affected EGU to cease operations by the federally enforceable date, including the approximate timing and duration of each step.

(B) A list of key milestones, metrics that will be used to assess whether each milestone has been met, and calendar day deadlines for each milestone. These milestones must include at least the following: notice to the official reliability authority of the federally enforceable retirement date; submittal of an official suspension filing (or equivalent filing) made to the affected EGU's reliability authority; and submittal of an official retirement filing with the unit's reliability authority.

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar units within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority, as well as any filings with the SEC or notices to investors in which the plans for the EGU are mentioned and any integrated resource plan.

(ii) For each of the remaining years prior to the federally enforceable date used to determine the applicable subcategory, affected EGUs must submit an annual Milestone Status Report that addresses the following:

(A) Progress toward meeting all milestones and related metrics identified in the Milestone Report; and

(B) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months following the date on which the affected EGU permanently ceased operations, the EGU must submit a Final Milestone Status Report that documents what the unit has done to make the closure permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) Affected EGUs with reporting milestones for enforceable commitments to cease operations would be required to post their initial Milestone Report, annual Milestone Status Reports, and final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the CAA Section 111(d) EGU Rule Website required by subsection (7) of this section within 30 business days of being filed.

(5) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(6) *State reporting.* You must include in your plan a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress.

(7) *CAA Section 111(d) EGU Rule Website*. You must include in your plan information about the establishment of “CAA Section 111(d) EGU Rule Website” and requirements for the owners or operators of affected EGUs to post relevant documents to this website. State plans must require affected EGUs to post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. State plans must also require affected EGUs with increments of progress to post those increments, the schedule required in the state plan for achieving them, and any documentation necessary to demonstrate that they have been achieved to this website in a timely manner. State plans must require affected EGUs to post a report of any deviation from any federally enforceable increment of progress or milestone to this website in a timely manner.

(b) You must follow the requirements of subpart Ba of this part and demonstrate that they were met in your State plan.

§ 60.5760b What are the timing requirements for submitting my State plan?

(a) You must submit a State plan with the information required under § 60.5740b by [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE].

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

§ 60.5775b What standards of performance must I include in my plan?

(a) Standard(s) of performance for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.
(2) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.
(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an emission standard in another State plan.
(4) An affected EGU's standard of performance is permanent if the emission standard must be met continuously, unless it is replaced by another emission standard in an approved plan revision, or the State demonstrates in an approvable plan revision..
(5) An affected EGU's standard of performance is enforceable if:
    (i) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;
    (ii) Compliance requirements are clearly defined;
    (iii) The affected EGUs responsible for compliance and liable for violations can be identified;
    (iv) Each compliance activity or measure is enforceable as a practical matter; and
    (v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)-(h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

(b) *Subcategories of affected EGUs*. States must subcategorize existing fossil fuel-fired steam generating units into one of the following subcategories:

(1) Long-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that have not adopted a federally enforceable commitment to cease operations by January 1, 2040.
(2) Medium-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that choose to adopt a federally enforceable commitment to cease operations after December 31, 2031, and before January 1, 2040, and that are not near-term units.
(3) Near-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that choose to adopt federally enforceable commitments to cease operations after December 31, 2031, and before January 1, 2035, and to operate with annual capacity factors less than 20 percent.
(4) Imminent-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that choose to adopt a federally enforceable commitment to cease operations before January 1, 2032.
(5) Base load continental existing oil-fired steam generating units, consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(6) *Intermediate load continental existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
(7) *Low load (continental and non-continental) existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.
(8) *Intermediate and base load non-continental existing oil-fired steam generating units,* consisting of non-continental oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent.
(9) *Base load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent
(10) *Intermediate load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
(11) *Low load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.

(c) Methodology for establishing presumptively approvable standards of performance, or presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term existing coal-fired steam generating units
  (i) BSER is CCS with 90 percent capture of CO_2.
  (ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
(2) Medium-term existing coal-fired steam generating units
  (i) BSER is natural gas co-firing at 40 percent of the heat input to the unit
  (ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is a 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline
  (iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, states must account for such preexisting co-firing in adjusting the degree of emission limitation (e.g., for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 30 percent to reflect the preexisting level of natural gas co-firing).
(3) Near-term existing coal-fired steam generating units
  (i) BSER is routine methods of operation
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline
(4) Imminent-term existing coal-fired steam generating units
  (i) BSER is routine methods of operation
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline
(5) Base load continental existing oil-fired steam generating units
  (i) BSER is routine methods of operation and maintenance

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,300 lb CO_2/MWh-gross

(6) Intermediate load continental existing oil-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,500 lb CO_2/MWh-gross

(7) Low load (continental and non-continental) existing oil-fired steam generating units do not have requirements.

(8) Intermediate and base load non-continental existing oil-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
(iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline

(9) Base load existing natural gas-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,300 lb CO_2/MWh-gross

(10) Intermediate load existing natural gas-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,500 lb CO_2/MWh-gross

(11) Low load existing natural gas-fired steam generating units do not have requirements.

(d) Methodology for establishing baseline emission performance for each affected EGU.

(1) A state shall use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5 years immediately prior to [INSERT DATE OF PUBLICATION OF FINAL RULE], based on the NSR/PSD program’s definition of “baseline actual emissions” for existing electric steam generating units. See 40 CFR 52.21(b)(48)(i).

(2) Although eight quarters of 40 CFR part 75 data corresponds to a 2-year calendar period (and corresponds to quarterly reporting), states shall utilize the most representative continuous 8-quarter period of data from the 5 years immediately preceding [INSERT DATE OF PUBLICATION OF FINAL RULE].

(3) For the continuous 8 quarters of data, a state shall divide the total CO_2 emissions (in the form of pounds) over that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh.

(e) *Remaining Useful Life and Other Factors (RULOF).* CAA section 111(d)(1)(B) permits states to take into consideration a particular affected EGU’s RULOF when applying a standard of performance to that source. A state may apply a less stringent standard of performance to an affected EGU when the state can demonstrate that the source cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA.

(1) A state may apply a less stringent standard of performance to a particular affected EGU, taking into consideration RULOF, provided that the state demonstrates with respect to that particular affected EGU that it cannot reasonably apply the BSER to achieve the degree of emission limitation determined via the methodology in subsection (c) of this section, based on one of more of three circumstances:

(i) unreasonable cost of control resulting from plant age, location, or basic process design;

(ii) physical impossibility or technical infeasibility of installing necessary control equipment; or

(iii) other circumstances specific to the facility that are fundamentally different from the information considered in the determination of the BSER..

(2) A state may not invoke RULOF based on minor, non-fundamental differences between a particular affected EGU and the degree of emission limitation determined via the methodology in subsection (c) of this section. For example, there could be instances in which an affected EGU may not be able to comply with the presumptively approvable standard of performance based on the precise metrics of the BSER determination but is able to do so within a reasonable margin.

(3) States invoking RULOF for affected coal-fired EGUs in the long-term subcategory must evaluate natural gas co-firing as a potential source-specific BSER. Additionally, if an EGU in the long-term subcategory can implement CCS but cannot achieve the degree of emission limitation prescribed by the presumptive standard of performance, the state must evaluate CCS with a source-specific degree of emission limitation as a potential BSER.

(4) States invoking RULOF for affected coal-fired EGUs in the long-term and medium-term subcategories must evaluate different levels of natural gas co-firing. The state must evaluate lower levels of natural gas co-firing unless it has demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. States may also consider additional potential source-specific BSERs for affected EGUs in either subcategory.

(5) Pursuant to the requirement to consider the potential pollution impacts and benefits for impacted communities, state plan submissions must demonstrate that the state considered where and how a less stringent standard of performance impacts these communities. The plan submission must clearly identify impacted communities and how it determined which communities were considered. In evaluating potential source-specific BSERs, a state must describe the health and environmental impacts anticipated from each control option it considered. A state must document how it considered these impacts, including any health and environmental benefits of control options, in determining the source-specific BSER. A state must consider and include in its state plan submission any feedback received during meaningful engagement regarding any proposed RULOF standard of performance for an affected EGU.

§ 60.5785b What is the procedure for revising my plan?

EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart Ba of this part. If one (or more) of the elements of the plan set in § 60.5740b require revision, a request must be submitted to the Administrator indicating the proposed revisions to the plan.

Applicability of Plans to Affected EGUs

§ 60.5840b Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, affected EGU owners or operators must comply with the plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a State plan to implement and enforce the emission guidelines contained in this subpart by [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE], or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State that commenced construction on or before January 8, 2014.

§ 60.5845b What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected steam generating unit that was in operation or had commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraph (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

§ 60.5850b What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) EGUs that are subject to subpart TTTT or TTTTa of this part as a result of commencing construction after the subpart TTTT or TTTTa applicability date;

(b) Steam generating units subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output or 219,000 MWh;

(c) Non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(d) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(e) Units that serve a generator along with other steam generating unit(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less;

(f) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(g) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(h) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (8) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet emission standards must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, only “valid operating hours,”, *i.e.,* full or partial unit (or stack) operating hours for which:

(i) “Valid data” (as defined in § 60.5880b) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data,and

(ii) The corresponding hourly gross energy output value is also valid data (**Note:** For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based emission standards, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage (CCS)), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each “valid operating hour” (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(5) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an

hourly basis useful thermal output and, if applicable, mechanical output, which are used with gross electric output to determine grossenergy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine P_{net} the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{\text{TDF}} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

WHERE:
P_{NET} = NET ENERGY OUTPUT OF YOUR AFFECTED EGU FOR EACH VALID OPERATING HOUR (AS DEFINED IN 60.5860(A)(2)) IN MWH.
$(PE)_{ST}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STEAM TURBINES IN MWH.
$(PE)_{CT}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STATIONARY COMBUSTION TURBINE(S) IN MWH.
$(PE)_{IE}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF YOUR AFFECTED EGU'S INTEGRATED EQUIPMENT THAT PROVIDES ELECTRICITY OR MECHANICAL ENERGY TO THE AFFECTED EGU OR AUXILIARY EQUIPMENT IN MWH.
$(PE)_{A}$ = ELECTRIC ENERGY USED FOR ANY AUXILIARY LOADS IN MWH.
$(PT)_{PS}$ = USEFUL THERMAL OUTPUT OF STEAM (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) THAT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU. THIS IS CALCULATED USING THE EQUATION SPECIFIED IN PARAGRAPH (A)(5)(V) OF THIS SECTION IN MWH.
$(PT)_{HR}$ = NON-STEAM USEFUL THERMAL OUTPUT (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM HEAT RECOVERY THAT IS USED FOR APPLICATIONS OTHER THAN STEAM GENERATION OR PERFORMANCE ENHANCEMENT OF THE AFFECTED EGU IN MWH.
$(PT)_{IE}$ = USEFUL THERMAL OUTPUT (RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM ANY INTEGRATED EQUIPMENT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL STEAM, ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU IN MWH.
TDF = ELECTRIC TRANSMISSION AND DISTRIBUTION FACTOR OF 0.95 FOR A COMBINED HEAT AND POWER AFFECTED EGU WHERE AT LEAST ON AN ANNUAL BASIS 20.0 PERCENT OF THE TOTAL GROSS OR NET ENERGY OUTPUT CONSISTS OF ELECTRIC OR DIRECT MECHANICAL OUTPUT AND 20.0 PERCENT OF THE TOTAL NET ENERGY OUTPUT CONSIST OF USEFUL THERMAL OUTPUT ON A 12-OPERATING MONTH ROLLING AVERAGE BASIS, OR 1.0 FOR ALL OTHER AFFECTED EGUS.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

WHERE:
Q_M = MEASURED STEAM FLOW IN KILOGRAMS (KG) (OR POUNDS (LBS)) FOR THE OPERATING HOUR.
H = ENTHALPY OF THE STEAM AT MEASURED TEMPERATURE AND PRESSURE (RELATIVE TO SATP CONDITIONS OR THE ENERGY IN THE CONDENSATE RETURN LINE, AS APPLICABLE) IN JOULES PER KILOGRAM (J/KG) (OR BTU/LB).
CF = CONVERSION FACTOR OF 3.6×10^9 J/MWH OR 3.413×10^6 BTU/MWH.

(vi) For rate-based standards, sum all of the values of P_{net} for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values for the valid operating hours to determine the CO_2 emissions rate (lb/net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) Consistent with § 60.5775b or § 60.5780b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) [Reserved]

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or

record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you the information in paragraphs (d)(1) through (4) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour;

(ii) The net electric output and the net energy output (P_{net}) values for each valid operating hour;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour ;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours; and

(v) The calculated CO_2 mass emission rate (lbs/net MWh).

(3) [Reserved]

(4) For each affected EGU the report rt must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate in units of the emission standard.

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under § 60.5740b if applicable.

(f) If an affected EGU captures CO_2 to meet the applicable emission limit, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98 subpart RR or subpart VV, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR or subpart VV, if injection occurs off-site.

Recordkeeping and Reporting Requirements

§ 60.5865b What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 10 years from the date the record is used to determine compliance with an emissions standard or plan requirement.. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5875b How do I submit information required by these emission guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE], deadline for plan submittal so that the official will have the ability to submit the initial or final plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§ 60.5880b What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, Ba, TTTT, and TTTTa, of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5845b.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal-fired steam generating unit means an electric utility steam generating unit or IGCC unit that meets the definition of “fossil fuel-fired” and that burns coal for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as “cogeneration”) means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired or oil-fired steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means: (1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to standard ambient temperature and pressure conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Oil-fired steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.4, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2023-0072; FRL-XXXX]

RIN 2060-AV09 and 2060-AV10

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

AGENCY: Environmental Protection Agency (EPA)

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing amendments to the new source performance standards (NSPS) for greenhouse gas (GHG) emissions from new fossil fuel-fired stationary combustion turbine electric generating units (EGUs) based upon the eight-year review required by the Clean Air Act (CAA). The EPA is also proposing to repeal the Affordable Clean Energy rule (ACE Rule) and is proposing new emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs, to replace the repealed ACE Rule.

DATES: *Comments.* Comments must be received on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Comments on the information collection provisions submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA) are best assured of consideration by OMB if OMB receives a copy of your comments on or before **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].**

Public Hearing. The EPA will hold a virtual public hearing on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** and **[INSERT DATE 16 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. See **SUPPLEMENTARY INFORMATION** for information on registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA-HQ-OAR-2023-0072, by any of the following methods:

- Federal eRulemaking Portal: *https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- Email: *a-and-r-docket@epa.gov*. Include Docket ID No. EPA-HQ-OAR-2023-0072 in the subject line of the message.
- Fax: (202) 566-9744. Attention Docket ID No. EPA-HQ-OAR-2023-0072.
- Mail: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OAR-2023-0072, Mail Code 28221T, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.
- Hand/Courier Delivery: EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue, NW, Washington, DC 20004. The Docket Center’s hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov*, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Mr. Christian Fellner, Sector Policies and Programs Division (D243-02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-4003; and email address: *fellner.christian@epa.gov* and Ms. Lisa Thompson, Sector Policies and Programs Division (D243-02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-9775; and email address: [redacted]*epa.gov*.

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** and **[INSERT DATE 16 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** and will convene at 11:00 a.m. Eastern Time (ET) and conclude at 7:00 p.m. ET each day. If the EPA receives a high volume of registrations for the public hearing, the EPA may continue the public hearing on **[INSERT DATE 17 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. On each hearing day, the EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-electric-utilities*.

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following the publication of this document in the *Federal Register*. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-electric-utilities* or contact the public hearing team at (888) 372-8699 or by email at *SPPDpublichearing@epa.gov*. The last day to pre-register to speak at the hearing will be **[INSERT DATE 12 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-electric-utilities*.

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony by submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-electric-utilities*. While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372-8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the *Federal Register* announcing updates.

If you require the services of an interpreter or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by **[INSERT DATE 7 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for these rulemakings under Docket ID No. EPA-HQ-OAR-2023-0072. All documents in the docket are listed in the Regulations.gov index. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy.

Written Comments. Direct your comments to Docket ID No. EPA-HQ-OAR-2023-0072 at *https://www.regulations.gov* (our preferred method), or the other methods identified in the ADDRESSES section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

The *https://www.regulations.gov* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov*, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and should be free of any defects or viruses.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov*. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Written Comments* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g*., Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov* and, as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA-HQ-OAR-2023-0072. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE	Affordable Clean Energy rule
BACT	best available control technology
BSER	best system of emissions reduction
Btu	British thermal unit

CAA	Clean Air Act
CBI	Confidential Business Information
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CFR	Code of Federal Regulations
CHP	combined heat and power
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EGU	electric generating unit
EIA	Energy Information Administration
EJ	environmental justice
EO	Executive Order
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
FEED	front-end engineering and design
FGD	flue gas desulfurization
FR	*Federal Register*
FrEDI	Framework for Evaluating Damages and Impacts
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GW	gigawatt
HHV	higher heating value
HRSG	heat recovery steam generator
IBR	incorporate by reference
ICR	information collection request
IGCC	integrated gasification combined cycle
IIJA	Infrastructure Investment and Jobs Act
IPCC	Intergovernmental Panel on Climate Change
IRC	Internal Revenue Code
IRP	integrated resource plan
kg	kilogram
kWh	kilowatt-hour
LCOE	levelized cost of electricity
LHV	lower heating value
LNG	liquefied natural gas
MMBtu/hr	million British thermal units per hour
MMst	million short tons
MMT CO_2e	million metric tons of carbon dioxide equivalent
MW	megawatt
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards

NAICS	North American Industry Classification System
NCA4	2017–2018 Fourth National Climate Assessment
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPS	new source performance standards
NSR	New Source Review
OMB	Office of Management and Budget
PM	particulate matter
PSD	Prevention of Significant Deterioration
PUC	public utilities commission
RIA	regulatory impact analysis
RPS	renewable portfolio standard
RTO	Regional Transmission Organization
SCR	selective catalytic reduction
SIP	state implementation plan
U.S.	United States
U.S.C.	United States Code

Organization of this document. The information in this preamble is organized as follows:

I. Executive Summary

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare.[1] In 2015, the EPA further concluded that fossil fuel-fired EGUs – which at that time were the nation's largest source of GHG emissions, and in 2020 represented 25 percent of total emissions – significantly contribute to that endangerment.[2] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.

In these actions, the EPA is proposing requirements to reduce emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs (primarily natural gas-fired turbines) and existing fossil fuel-fired steam generating EGUs (primarily coal-fired utility boilers). The EPA is also soliciting comment on options to address GHGs from existing fossil

[1] 74 FR 66496 (December 15, 2009).
[2] 80 FR 64531 (October 23, 2015).

fuel-fired stationary combustion turbine EGUs (primarily natural gas-fired). These proposed requirements focus on technologies, such as carbon capture and storage (CCS), hydrogen co-firing, and natural gas co-firing, that can be applied directly to the sources in question.

These proposed requirements are informed by recent market and policy developments that are driving rapid changes in overall generating capacity and patterns of utilization for new and existing fossil fuel-fired EGUs. A number of factors are leading to significant changes in the way electricity is generated in this country that are changing the economics of both coal- and gas-fired generation. The power sector has innovated, developing new tools to reduce GHG emissions from its sources, and states have implemented a range of different programs to reduce GHGs from the power sector. Congress has also acted in significant ways affecting the power sector, providing funding and other incentives to spur the deployment of low GHG technologies and encourage reductions in GHG emissions. These significant trends have played an important role in the EPA's understanding of the economics of the control technologies that were evaluated to design these proposals, as well as the impacts of the proposed standards on this sector.

These proposals address the statutory command of section 111 of the Clean Air Act (CAA)—to establish standards of performance for emissions of air pollutants that reflect application of the best system of emissions reduction (BSER)—by leveraging adequately demonstrated GHG control technologies to significantly reduce emissions of dangerous pollution from fossil fuel-fired EGUs, taking into account costs, energy requirements, and other statutory factors. The EPA is proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs to take advantage of advancements in efficiency, hydrogen co-firing, and CCS. The EPA is also proposing to repeal the ACE Rule and is proposing new emission guidelines to replace the repealed ACE Rule. The EPA is proposing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, taking advantage of advancements in CCS and the availability of natural gas co-firing, and paying due attention to the real-world changes that are underway for those EGUs as they age and face significant economic competition from other electricity generating technologies. The EPA is also soliciting comment on how the Agency should approach its legal obligation to establish emission guidelines for existing fossil fuel-fired combustion turbine EGUs.

In all of these efforts, the EPA seeks to ensure that EGUs reduce their GHG emissions in a cost-effective and achievable way to address the danger posed by those emissions, mindful of the guidance the EPA has received from the courts. These proposed standards and emission guidelines, if finalized, would significantly decrease the GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. The EPA has designed these proposed standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of electricity.

A. Climate Change and the Power Sector

These proposals focus on reducing the emissions of GHGs from the power sector. The increasing concentrations of GHGs in the atmosphere are, and have been, warming the planet, resulting in serious and life-threatening environmental and human health impacts. The increased concentrations of GHGs in the atmosphere and the resulting warming have led to more frequent and more intense heat waves and extreme weather events, rising sea levels, and retreating snow and ice, all of which are occurring at a pace and scale that threatens human welfare.

The power sector in the United States (U.S.) is both a key contributor to the cause of climate change and a key component of the solution to the climate challenge. In 2020, the power sector was the largest stationary source of GHGs, emitting 25 percent of the overall domestic emissions.[3] These emissions are almost entirely the result of the combustion of fossil fuels in the EGUs that are the subjects of these proposals.

The power sector possesses many opportunities to contribute to solutions to the climate challenge. Particularly relevant to these proposals are several key technologies (co-firing of low-GHG fuels and CCS) that can allow steam generating EGUs and stationary combustion turbines (the focus of these proposals) to provide power while emitting significantly less GHG emissions. Moreover, with the increased drive to electrify other GHG-emitting sectors of the economy, such as personal vehicles, heavy-duty trucks, and the heating and cooling of buildings, a power sector with lower GHG emissions can also help reduce pollution coming from other sectors of the economy.

B. State of the Power Sector

These proposals occur at a time of great and accelerating change in the power sector. As the existing fossil fuel-fired fleet ages (as of late 2021, the average age of the coal-fired fleet was 45 years old[4]), Federal and state legislation, technology advancements, market forces, and consumer demand are pushing the industry toward increased use of new lower-emitting generation sources and away from the higher-emitting fossil fuel-fired units that are the subjects of these proposals. Between 2010 and 2021, fossil fuel-fired generation declined from approximately 70 percent of total net generation to approximately 60 percent, with coal generation dropping most precipitously, from 46 percent to 23 percent of net generation during

[3] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions*.
[4] *https://www.eia.gov/todayinenergy/detail.php?id=50658#:~:text=The%20average%20operating%20coal%2Dfired,States%20is%2045%20years%20old*.

the period. The economics of the power sector have shifted dramatically, and technological innovations have increasingly made low- and zero-emitting sources more competitive with fossil fuel-derived power generating sources.[5]

Many utilities and power generating companies have already announced GHG reduction commitments as they further analyze and consider the incentives of the recently enacted Inflation Reduction Act (IRA), which is discussed in greater detail later in this preamble. These utilities and companies have also announced their intention to retire a significant number of their remaining coal-fired EGUs. Some are replacing those coal-fired units with natural gas-fired combustion turbines while others are replacing those units with alternatives such as renewable generating sources and energy storage. Some companies are planning to install combustion turbines with advanced technologies to limit GHG emissions, including CCS and hydrogen co-firing (with a number of companies having announced plans to ultimately move to 100 percent hydrogen firing) and advanced energy storage technologies that either have longer storage capacity than lithium-ion batteries and/or use more common materials and are lower cost. Others are exploring the use of advanced technologies such as distributed generation through the use of virtual power plants and small modular nuclear reactors. As more renewables come online and as these technologies become more widely deployed, many experts have projected that utilization of natural gas-fired combustion turbine EGUs will significantly decrease. Indeed, the Post-IRA 2022 reference case modeling for this proposal projects lower utilization relative to current levels of stationary combustion turbines even without consideration of advanced energy storage, virtual power plants, and small modular nuclear reactors (see section IV.F. of this preamble).

[5] *https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/*.

The power sector's trajectory has also been greatly influenced by the actions of state governments that are interested in limiting GHG pollution for the benefit of their citizens. More than two-thirds of states have enacted policies to require utilities to increase the amount of electricity generated from sources that emit no GHGs. Other states have recently enacted significant legislation requiring the decarbonization of their utility fleets, using devices such as carbon markets, low-GHG emission standards, carbon capture and storage mandates, utility planning, or mandatory retirement schedules.

During this time of dynamic change, Congress enacted historic investments in GHG reductions. Through the Infrastructure Investment and Jobs Act (IIJA), Congress infused more than $65 billion of infrastructural investments and upgrades that will provide needed transmission capacity, pipelines, and low-carbon fuels (such as low-GHG hydrogen) for the power sector. In addition, the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS Act) authorized billions more in funding for development of low- and non-GHG emitting energy technologies that will provide additional low-cost options for power companies to reduce overall GHG emissions.

Perhaps the most significant effects for the power sector will result from the IRA, which was signed into law on August 16, 2022. With billions of dollars in investments in the transition to clean energy, the IRA promises to promote industrial investment toward low- and non-GHG emitting generation at a much faster pace. The IRA's provisions represent a cross-sectoral drive to push the power sector away from GHG-emitting sources through a broad array of tax credits, loan guarantees, and public investment programs. These provisions are not only aimed at creating incentives for new cleaner generating assets that are not subject to this proposal, but also at limiting GHG emissions from the fossil fuel-fired generating sources that are the subjects of these proposals, with tax credits for use of CCS and for hydrogen production and use that provide pathways for the use of fossil fuels as part of a low-carbon electricity grid.

These proposals likewise focus on just such "measures that improve the pollution performance of individual sources."[6] While the legislative programs described are considered in the regulatory impact analysis (RIA) as part of the Agency's overall assessment of the costs, benefits, and power sector impacts of these proposals, the EPA has not considered shifts in generation (either among different fossil generation technologies or to non-fossil technologies) in determining the BSER. As described in more detail below, the EPA has also designated subcategories of fossil fuel-fired EGUs that correspond with the power sector's ongoing and rapid transition, and take account of how recent legislative, policy, and market developments affect the emission reductions, costs, and feasibility of GHG control technologies for improving the pollution performance of the specific types of EGUs for which the EPA is proposing standards of performance and emission guidelines in this rulemaking. While the EPA has focused on ensuring that sources that have the potential to emit large amounts of GHGs and that will be providing power over a long time horizon install technologies that address these emissions, the EPA has also analyzed the cost reasonableness of installing such equipment at sources that may be retiring in the shorter term and has designed this proposal to avoid the need to install highly capital-intensive control equipment at those sites.

The EPA also recognizes that these proposals are not the only recent regulatory actions impacting these sources and is attempting, consistent with its statutory obligations under CAA section 111, to establish NSPS and emission guidelines that are well-aligned with other known regulatory obligations. This will enable owners and operators of EGUs to make informed

[6] *West Virginia v. EPA*, 142 S. Ct. 2587, 2615 (2022).

investment decisions moving forward. Finally, given the pace of the projected transition within the power sector, the EPA understands that careful planning is needed to ensure that compliance with the provisions of these proposals does not result in any generation deficiencies that will undercut the delivery of reliable power to customers. With that in mind, the EPA has included in these proposals the flexibility operators need to achieve critical reductions of GHGs from these sources while ensuring grid reliability. These proposals consider each of these factors.

C. Overview of the Proposals

These actions include proposed BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines, proposed BSER determinations and proposed emission guidelines for existing fossil fuel-fired steam generating units, and solicitation for comment on potential BSER options and emission guidelines for existing fossil fuel-fired stationary combustion turbines.

For new and reconstructed fossil fuel-fired combustion turbines, the EPA is proposing to create three subcategories based on the function the combustion turbine serves: a low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor[7] of less than 20 percent; an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine; and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. This subcategorization approach is similar to the current NSPS for these sources, which includes separate subcategories

[7] The applicability threshold is determined on both a 12-operating month and 3 calendar year average.

for base load and non-base load units, but in contrast to the current NSPS for these sources, creates two subcategories from what is currently the non-base load subcategory.

For the low load subcategory, the EPA is proposing that the BSER is the use of lower emitting fuels (*e.g.*, natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted. For the intermediate load and base load subcategories, the EPA is proposing an approach in which the BSER has two components—(1) highly efficient generation; and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen.

These components form the basis of a standard of performance that applies in two phases. That is, affected facilities – which are facilities that commence construction or reconstruction after the date of publication in the *Federal Register* of this proposed rulemaking – must meet the first phase of the standard of performance, based on application of the first component of the BSER, highly efficient generation, by the date the rule is promulgated. They must also meet the second and more stringent phase of the standard of performance, which is based on application of both the first component and the second component of the BSER, which is the use of CCS or co-firing low-GHG hydrogen, by 2035. It should be noted that although the first phase of the standard of performance is based on only the application of the first component of the BSER, the second phase is based on the application of both components. Indeed, utilization of highly efficient generation is a logical complement to both CCS and co-firing of low-GHG hydrogen because, from both an economic and emissions perspective, that configuration will provide the greatest reductions at the lowest cost. This approach reflects the EPA's view that the BSER for the intermediate load and base load subcategories should reflect the deeper reductions in GHG emissions that can be achieved by implementing CCS and co-firing low-GHG hydrogen with the most efficient stationary combustion turbine configuration available; however, EPA is proposing compliance not begin until 2035, because it. EPA recognizes that building the infrastructure required to support wider spread use of CCS and qualified low-GHG hydrogen in the power sector will take place on a multi-year time scale.

More specifically, with respect to the first phase of the standards of performance, the EPA is proposing that the BSER for both the intermediate load and base load subcategories includes highly efficient generating technology (*i.e.*, the most efficient available turbines). For the intermediate load subcategory, the EPA is proposing that the BSER includes highly efficient simple cycle turbine technology with an associated first phase standard of 1,150 lb CO_2/MWh-gross. For the base load subcategory, the EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb CO_2/MWh-gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rate less than 2,000 MMBtu/h), the proposed associated standard would range from 770 to 900 lb CO_2/MWh-gross depending on the specific base load rating of the combustion turbine. These standards would apply immediately upon the effective date of the final rule.

With respect to the second phase of the standards of performance, compliance with which would be required starting in 2035, for the intermediate load subcategory, the EPA is proposing that the BSER includes co-firing 30 percent[8] low-GHG hydrogen with an associated standard of 1,000 lb CO_2/MWh. For the base load subcategory, the EPA is proposing to subcategorize further into base load units that are not combusting at least 10 percent hydrogen, and base load

[8] This is 30 percent low-GHG hydrogen by volume, which is 12 percent low GHG-hydrogen by heat input. Unless otherwise noted, all mentions of co-firing hydrogen are provided in volume percentages.

units that are combusting at least 10 percent hydrogen. For the subcategory of base load units that are not combusting at least 10 percent hydrogen, the EPA is proposing that the BSER includes the use of CCS with 90 percent capture of CO_2 with an associated standard of 90 lb CO_2/MWh. For the subcategory of base load units that are combusting at least 10 percent hydrogen, the EPA is proposing that the BSER includes co-firing 30 percent low-GHG hydrogen with an associated standard of 680 lb CO_2/MWh.

This preamble also announces the Agency's intention to rescind a 2018 proposal to amend the NSPS for new, reconstructed, and modified coal-fired steam generating units. Additionally, the EPA is also proposing to repeal the existing ACE Rule emission guidelines.

For the emission guidelines for existing coal-fired steam generating units, the EPA is proposing to create four subcategories based on the operating horizon of the units. The EPA recognizes that the coal-fired steam generating EGU fleet is aging and that many owners and operators are considering or have already announced plans to cease operation of their units between now and 2040. Therefore, the EPA is proposing that, for the subcategory of coal-fired steam generating units with the longest operating horizons, *i.e.*, those that plan to operate past December 31, 2039, the BSER is the use of CCS with 90 percent capture of CO_2 with an associated degree of emission limitation of an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis). For coal-fired steam generating units with medium-term operating horizons, *i.e.*, those that operate after December 31, 2031 and that choose to adopt federally enforceable commitments to permanently cease operations before January 1, 2040 and that do not meet the definition of near-term units, the EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis with an associated degree of emission limitation of a 16 percent reduction in emission rate (lb CO_2/MWh-gross basis). For units with operating horizons that are imminent-term, *i.e.*, those that choose to adopt federally enforceable commitments to permanently cease operations before January 1, 2032, or near-term, *i.e.*, those that choose to adopt a federally enforceable commitment to permanently cease operations after January 1, 2035 and that choose to adopt a federally enforceable annual capacity factor limit of 20 percent, the EPA is proposing that the BSER is routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate (lb CO_2/MWh-gross basis). Finally, for the emission guidelines for existing natural gas-fired and oil-fired steam generating units, the EPA is, in general, also proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).

For the emission guidelines for existing steam generating units, the EPA is also proposing state plan requirements, including submittal timelines for state plans and methodologies for determining presumptively approvable standards of performance consistent with BSER. This proposal also addresses how states can implement the remaining useful life and other factors (RULOF) provision of CAA section 111(d) and how states can conduct meaningful engagement with impacted stakeholders. Finally, this proposal discusses considerations related to the appropriateness of including emission trading or averaging in state plans.

Finally, the EPA is soliciting comment on a number of variations to the subcategories, BSER determinations, degrees of emission limitation, and standards of performance summarized above, as well as a BSER determination and degrees of emission limitation for existing fossil fuel-fired stationary combustion turbines.

II. General Information

A. Action Applicability

The source category that is the subject of these actions is comprised of the fossil fuel-fired electric utility generating units regulated under CAA section 111. The North American Industry Classification System (NAICS) codes for the source category are 221112 and 921150. The list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that these proposed actions are likely to affect.

The proposed amendments to 40 CFR part 60, subpart TTTT, once promulgated, will be directly applicable to affected facilities that began construction after January 8, 2014 and affected facilities that began reconstruction or modification after June 18, 2014. The proposed NSPS, proposed to be codified in 40 CFR part 60, subpart TTTTa, once promulgated, will be directly applicable to affected facilities that begin construction or reconstruction after the date of publication of the proposed standards in the *Federal Register*. Federal, state, local, and tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subparts TTTT or TTTTa would be affected by these proposed amendments and standards.

The proposed emission guidelines for GHG emissions from fossil fuel-fired EGUs proposed to be codified in 40 CFR part 60, subpart UUUUb, once promulgated, will be applicable to states in the development and submittal of state plans pursuant to CAA section 111(d). After the EPA promulgates a final emission guideline, each state that has one or more designated facilities must develop, adopt, and submit to the EPA a state plan under CAA section 111(d). The term "designated facility" means "any existing facility … which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility." See 40 CFR 60.21a(b). If a state fails to submit a plan or the EPA determines that a state plan is not satisfactory, the EPA has the authority to establish a Federal CAA section 111(d) plan in such instances.

Under the Tribal Authority Rule adopted by the EPA, tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a Tribal Implementation Plan (TIP) implementing an emission guideline. If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

B. Where to Get a Copy of This Document and Other Related Information

In addition to being available in the docket, an electronic copy of this action is available on the Internet at *https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-electric-utilities*. Following publication in the *Federal Register*, the EPA will post the *Federal Register* version of the proposals and key technical documents at this same website.

Memoranda showing the edits that would be necessary to incorporate the changes to 40 CFR part 60, subpart TTTT and UUUUa and new 40 CFR part 60, subparts TTTTa and UUUUb proposed in these actions are available in the docket (Docket ID No. EPA-HQ-OAR-2023-0072). Following signature by the EPA Administrator, the EPA also will post a copy of the documents at *https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-electric-utilities*.

C. Organization and Approach for These Proposed Rules

These actions present the EPA's proposed amendments to the Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (80 FR 64510; October 23, 2015) (2015 NSPS) and proposed requirements for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. These actions also propose to repeal the ACE Rule (84 FR 32523; July 8, 2019) and propose new emission guidelines for states in developing plans to reduce GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs, to replace the repealed ACE Rule. The EPA is also soliciting comment on how the Agency should approach the creation of emission guidelines for existing fossil fuel-fired stationary combustion turbines.

Section III of this preamble provides updated information on the impacts of climate change. In section IV, the EPA provides a summary of the current state of the power sector, including changes and trends, GHG emissions, and GHG reduction goals and commitments, and the impacts of recent legislation on these. Section V presents a summary of the statutory background and regulatory history. In section VI, the EPA summarizes stakeholder outreach efforts. In section VII, the EPA describes the proposed BSERs, standards of performance, and associated requirements for new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. In section VIII, the EPA presents proposed amendments to the applicability requirements for new, reconstructed, and modified fossil fuel-fired steam generating units. In section IX, the EPA provides a summary of the ACE Rule and proposes its repeal. In section X, the EPA presents the proposed BSERs, degree of emission limitation, and related requirements for the emission guidelines for existing fossil fuel-fired steam generating EGUs. Section XI presents the requirements for state plan development. In section XII, the EPA solicits comment on the creation of emission guidelines for existing natural gas-fired combustion turbines. In section XIII, the EPA describes the implications for these proposals and other EPA programs and rules. Section XIV describes the impacts of these proposals. Finally, in section XV, the EPA provides the statutory and executive order reviews.

III. Climate Change and Its Impacts

Elevated concentrations of GHGs are and have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events; rising seas; and retreating snow and ice. The changes taking place in the atmosphere as a result of the well-documented buildup of GHGs due to human activities are transforming the climate at a pace and scale that threatens human health, society, and the natural environment. Human-induced GHGs, largely derived from our reliance on fossil fuels, are causing serious and life-threatening environmental and health impacts.

Extensive additional information on climate change is available in the scientific assessments and the EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is the EPA's 2009 Endangerment and Cause or Contribute Findings for GHGs Under section 202(a) of the CAA (74 FR 66496; December 15, 2009).[9] In the 2009 Endangerment Findings, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—"may reasonably be

[9] In describing these 2009 Findings in this proposal, the EPA is neither reopening nor revisiting them.

anticipated to endanger the public health and welfare of current and future generations" (74 FR 66523; December 15, 2009), and the science and observed changes have confirmed and strengthened the understanding and concerns regarding the climate risks considered in the Finding. The 2009 Endangerment Findings, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497; December 15, 2009). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525; December 15, 2009). The 2009 Endangerment Findings further explained that compared to a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525; December 15, 2009). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525; December 15, 2009). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498; December 15, 2009).

The 2009 Endangerment Findings also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare[10] in the U.S. including changes in water supply and quality due to increased frequency of drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization). These impacts are also global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S. (74 FR 66530; December 15, 2009).

In 2016, the Administrator similarly issued Endangerment and Cause or Contribute Findings for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA (81 FR 54422; August 15, 2016).[11] In the 2016 Endangerment Findings, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Findings compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A) and also found that the science assessments released between the 2009 and the 2016 Findings, "strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations." 81 FR 54424 (August 15, 2016).

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[10] The CAA states in section 302(h) that "[a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants." 42 U.S.C. 7602(h).

[11] In describing these 2016 Findings in these proposals, the EPA is neither reopening nor revisiting them.

Since the 2016 Endangerment Findings, the climate has continued to change, with new records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Moreover, heavy precipitation events have increased in the eastern U.S. while agricultural and ecological drought has increased in the western U.S. along with more intense and larger wildfires.[12] These and other trends are examples of the risks discussed in the 2009 and 2016 Endangerment Findings that have already been experienced. Additionally, major scientific assessments continue to demonstrate advances in our understanding of the climate system and the impacts that GHGs have on public health and welfare both for current and future generations. These updated observations and projections document the rapid rate of current and future climate change both globally and in the U.S. These assessments include:

- U.S. Global Change Research Program's (USGCRP) 2016 Climate and Health Assessment[13] and 2017–2018 Fourth National Climate Assessment (NCA4).[14] [15]

[12] See later in this section for specific examples. An additional resource for indicators can be found at *https://www.epa.gov/climate-indicators*.
[13] USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp.
[14] USGCRP, 2017: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: 10.7930/J0J964J6.
[15] USGCRP, 2018: Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

- Intergovernmental Panel on Climate Change (IPCC) 2018 Global Warming of 1.5 °C,[16] 2019 Climate Change and Land,[17] and the 2019 Ocean and Cryosphere in a Changing Climate[18] assessments, as well as the 2021 IPCC Sixth Assessment Report (AR6).[19] [20]
- The National Academy of Sciences (NAS) 2016 Attribution of Extreme Weather Events in the Context of Climate Change,[21] 2017 Valuing Climate Damages: Updating

[16] IPCC, 2018: Global Warming of 1.5 °C. An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Portner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Pe´an, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[17] IPCC, 2019: Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Portner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley (eds.)].

[18] IPCC, 2019: IPCC Special Report on the Ocean and Cryosphere in a Changing Climate [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegrı´a, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[19] IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Pe´an, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekc¸i, R. Yu and B. Zhou (eds.)]. Cambridge University Press.

[20] IPCC, 2022: Summary for Policymakers [H.-O. Pörtner, D.C. Roberts, E.S. Poloczanska, K. Mintenbeck, M. Tignor, A. Alegría, M. Craig, S. Langsdorf, S. Löschke, V. Möller, A. Okem (eds.)]. In: Climate Change 2022: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [H.-O. Pörtner, D.C. Roberts, M. Tignor, E.S. Poloczanska, K. Mintenbeck, A. Alegría, M. Craig, S. Langsdorf, S. Löschke, V. Möller, A. Okem, B. Rama (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, New York, USA, pp. 3–33, doi:10.1017/9781009325844.001.

[21] National Academies of Sciences, Engineering, and Medicine. 2016. Attribution of Extreme Weather Events in the Context of Climate Change. Washington, DC: The National Academies Press. *https://dio.org/10.17226/21852*.

Estimation of the Social Cost of Carbon Dioxide,[22] and 2019 Climate Change and Ecosystems[23] assessments.

- National Oceanic and Atmospheric Administration's (NOAA) annual State of the Climate reports published by the Bulletin of the American Meteorological Society,[24] most recently in August of 2022.
- EPA Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts (2021).[25]

The most recent information demonstrates that the climate is continuing to change in response to the human-induced buildup of GHGs in the atmosphere. These recent assessments show that atmospheric concentrations of GHGs have risen to a level that has no precedent in human history and that they continue to climb, primarily as a result of both historic and current anthropogenic emissions, and that these elevated concentrations endanger our health by affecting our food and water sources, the air we breathe, the weather we experience, and our interactions with the natural and built environments. For example, the annual global average atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 415 parts per million (ppm) in 2020 (nearly 50 percent higher than pre-industrial levels)[26] and has continued to rise at a rapid rate. Global average temperature has

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[22] National Academies of Sciences, Engineering, and Medicine. 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. *https://doi.org/10.17226/24651*.
[23] National Academies of Sciences, Engineering, and Medicine. 2019. Climate Change and Ecosystems. Washington, DC: The National Academies Press. *https://doi.org/10.17226/25504*.
[24] Blunden, J. and T. Boyer, Eds., 2022: "State of the Climate in 2021." Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*.
[25] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.
[26] Blunden, J. and T. Boyer, Eds., 2022: "State of the Climate in 2021." Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*.

increased by about 1.1 degrees Celsius (°C) (2.0 degrees Fahrenheit (°F)) in the 2011–2020 decade relative to 1850–1900.[27] The years 2015–2021 were the warmest 7 years in the 1880–2020 record according to six different global surface temperature datasets.[28] The IPCC determined with medium confidence that this past decade was warmer than any multi-century period in at least the past 100,000 years.[29] Global average sea level has risen by about 8 inches (about 21 centimeters (cm)) from 1901 to 2018, with the rate from 2006 to 2018 (0.15 inches/year or 3.7 millimeters (mm)/year) almost twice the rate over the 1971 to 2006 period and three times the rate of the 1901 to 2018 period.[30] The rate of sea level rise during the 20th Century was higher than in any other century in at least the last 2,800 years.[31] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 2 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[32] Arctic sea ice extent continues to decline in all months of the year; the most rapid reductions occur in September (very likely almost a 13 percent decrease per decade between 1979 and 2018) and are unprecedented in at least 1,000 years.[33] Human-induced climate change has led to heatwaves and heavy precipitation becoming more frequent

[27] IPCC, 2021.
[28] Blunden, J. and T. Boyer, Eds., 2022.
[29] IPCC, 2021.
[30] IPCC, 2021.
[31] USGCRP, 2018: Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.
[32] IPCC, 2021.
[33] IPCC, 2021.

and more intense, along with increases in agricultural and ecological droughts[34] in many regions.[35]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The present-day CO_2 concentration of 415 ppm is already higher than at any time in the last 2 million years.[36] If concentrations exceed 450 ppm, they would likely be higher than at any time in the past 23 million years:[37] At the current rate of increase of more than 2 ppm per year, this will occur in about 15 years. While buildup of GHGs is not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were this high) Greenland was not yet completely covered by ice and still supported forests, while 23 million years ago (the last time concentrations were above 450 ppm) the West Antarctic ice sheet was not yet developed, indicating the possibility that high GHG concentrations could lead to a world that looks very different from today and from the conditions in which human civilization has developed.[38]

If the Greenland and Antarctic ice sheets were to melt substantially, for example, sea levels would rise dramatically, with potentially severe consequences for coastal cities and

[34] These are drought measures based on soil moisture.
[35] IPCC, 2021.
[36] IPCC, 2021.
[37] IPCC, 2013.
[38] Gulev, S.K., P.W. Thorne, J. Ahn, F.J. Dentener, C.M. Domingues, S. Gerland, D. Gong, D.S. Kaufman, H.C. Nnamchi, J. Quaas, J.A. Rivera, S. Sathyendranath, S.L. Smith, B. Trewin, K. von Schuckmann, and R.S. Vose, 2021: Changing State of the Climate System. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, New York, USA, pp. 287–422, doi:10.1017/9781009157896.004.

infrastructure. The IPCC estimated that during the next 2,000 years, sea level will rise by 7 to 10 feet even if warming is limited to 1.5 °C (2.7 °F), from 7 to 20 feet if limited to 2 °C (3.6 °F), and by 60 to 70 feet if warming is allowed to reach 5 °C (9 °F) above preindustrial levels.[39] For context, almost all of the city of Miami is less than 25 feet above sea level, and the NCA4 stated that 13 million Americans would be at risk of migration due to 6 feet of sea level rise. Moreover, the CO_2 being absorbed by the ocean has resulted in changes in ocean chemistry due to acidification of a magnitude not seen in 65 million years,[40] putting many marine species—particularly calcifying species—at risk.[41]

The NCA4 found that it is very likely (greater than 90 percent likelihood) that by mid-century, the Arctic Ocean will be almost entirely free of sea ice by late summer for the first time in about 2 million years.[42] Coral reefs will be at risk for almost complete (99 percent) losses with 1 °C (1.8 °F) of additional warming from today (2 °C or 3.6 °F since preindustrial). At this temperature, between 8 and 18 percent of animal, plant, and insect species could lose over half of the geographic area with suitable climate for their survival, and 7 to 10 percent of rangeland livestock would be projected to be lost.[43] The IPCC similarly found that climate change has caused substantial damages and increasingly irreversible losses in terrestrial, freshwater, and coastal and open ocean marine ecosystems.[44]

Every additional increment of temperature comes with consequences. For example, the half degree of warming from 1.5 to 2 °C (0.9 °F of warming from 2.7 °F to 3.6 °F) above

[39] IPCC, 2021.
[40] IPCC, 2018.
[41] IPCC, 2021.
[42] USGCRP, 2018.
[43] IPCC, 2018.
[44] IPCC, 2022.

preindustrial temperatures is projected on a global scale to expose 420 million more people to frequent extreme heatwaves and 62 million more people to frequent exceptional heatwaves (where heatwaves are defined based on a heat wave magnitude index which takes into account duration and intensity—using this index, the 2003 French heat wave that led to almost 15,000 deaths would be classified as an "extreme heatwave" and the 2010 Russian heatwave which led to thousands of deaths and extensive wildfires would be classified as "exceptional"). It would increase the frequency of sea-ice-free Arctic summers from once in a hundred years to once in a decade. It could lead to 4 inches of additional sea level rise by the end of the century, exposing an additional 10 million people to risks of inundation, as well as increasing the probability of triggering instabilities in either the Greenland or Antarctic ice sheets. Between half a million and a million additional square miles of permafrost would thaw over several centuries. Risks to food security would increase from medium to high for several lower income regions in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon. In addition to food security issues, this temperature increase would have implications for human health in terms of increasing ozone concentrations, heatwaves, and vector-borne diseases (for example, expanding the range of the mosquitoes which carry dengue fever, chikungunya, yellow fever, and the Zika virus or the ticks which carry lyme, babesiosis, or Rocky Mountain Spotted Fever).[45] Moreover, every additional increment in warming leads to larger changes in extremes, including the potential for events unprecedented in the observational record. Every additional degree will intensify extreme precipitation events by about 7 percent. The peak winds of the most intense tropical cyclones (hurricanes) are projected to increase with warming. In addition to a higher intensity, the IPCC found that precipitation and frequency of rapid intensification of these storms has already

[45] IPCC, 2018.

increased, while the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[46]

The NCA4 also evaluated a number of impacts specific to the U.S. Severe drought and outbreaks of insects like the mountain pine beetle have killed hundreds of millions of trees in the western U.S. Wildfires have burned more than 3.7 million acres in 14 of the 17 years between 2000 and 2016, and Federal wildfire suppression costs were about a billion dollars annually.[47] The National Interagency Fire Center has documented U.S. wildfires since 1983, and the 10 years with the largest acreage burned have all occurred since 2004.[48] Wildfire smoke degrades air quality increasing health risks, and more frequent and severe wildfires due to climate change would further diminish air quality, increase incidences of respiratory illness, impair visibility, and disrupt outdoor activities, sometimes thousands of miles from the location of the fire. Meanwhile, sea level rise has amplified coastal flooding and erosion impacts, leading to salt water intrusion into coastal aquifers and groundwater, flooding streets, increasing storm surge damages, and threatening coastal property and ecosystems, requiring costly adaptive measures such as installation of pump stations, beach nourishment, property elevation, and shoreline armoring. Tens of billions of dollars of U.S. real estate could be below sea level by 2050 under some scenarios. Increased frequency and duration of drought will reduce agricultural productivity in some regions, accelerate depletion of water supplies for irrigation, and expand the distribution and incidence of pests and diseases for crops and livestock. The NCA4 also recognized that climate change can increase risks to national security, both through direct

[46] IPCC, 2021.
[47] USGCRP, 2018.
[48] NIFC (National Interagency Fire Center). 2022. Total wildland fires and acres (1983–2020). Accessed November 2022. *https://www.nifc.gov/sites/default/files/document-media/TotalFires.pdf*.

impacts on military infrastructure, but also by affecting factors such as food and water availability that can exacerbate conflict outside U.S. borders. Droughts, floods, storm surges, wildfires, and other extreme events stress nations and people through loss of life, displacement of populations, and impacts on livelihoods.[49]

Some GHGs also have impacts beyond those mediated through climate change. For example, elevated concentrations of CO_2 stimulate plant growth (which can be positive in the case of beneficial species, but negative in terms of weeds and invasive species, and can also lead to a reduction in plant micronutrients)[50] and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[51] The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects.[52]

Ongoing EPA modeling efforts can shed further light on the distribution of climate change damages expected to occur within the U.S. Based on methods from over 30 peer-reviewed climate change impact studies, the EPA's Framework for Evaluating Damages and Impacts (FrEDI) model has developed estimates of the relationship between future temperature

[49] USGCRP, 2018.
[50] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Perez de Leon, A.Showler, J. Thurston, and I. Walls, 2016: Ch. 7: Food Safety, Nutrition, and Distribution. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. U.S. Global Change Research Program, Washington, DC, 189– 216, *https://dx.doi.org/10.7930/J0ZP4417*.
[51] WMO (World Meteorological Organization), Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project— Report No. 58, 588 pp., Geneva, Switzerland, 2018.
[52] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4. 2018. CH13.

changes and physical and economic climate-driven damages occuring in specific U.S. regions across 20 impact categories, which span a large number of sectors of the U.S. economy.[53] Recent applications of FrEDI have advanced the collective understanding about how future climate change impacts in these 20 sectors are expected to be substantial and distributed unevenly across U.S. regions.[54] Using this framework, the EPA estimates that under a global emission scenario with no additional mitigation, relative to a world with no additional warming since the baseline period (1986–2005), damages accruing to these 20 sectors in the contiguous U.S. occur mainly through increased deaths due to increasing temperatures, as well as climate-driven changes in air quality, transportation impacts due to coastal flooding resulting from sea level rise, increased mortality from wildfire emission exposure and response costs for fire suppression, and reduced labor hours worked in outdoor settings and buildings without air conditioning. The relative damages from long-term climate driven changes in these sectors are also projected vary from region to region: for example, the Southeast is projected to see some of the largest damages from sea level rise, the West Coast will see higher damages from wildfire smoke than other parts of the country, and the Northern Plains states are projected to see a higher proportion of damages to

[53] EPA. (2021). Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI). U.S. Environmental Protection Agency, EPA 430-R-21-004, available at *https://www.epa.gov/cira/fredi*. Documentation has been subject to both a public review comment period and an independent expert peer review, following EPA peer-review guidelines.
[54] (1) Sarofim, M.C., Martinich, J., Neumann, J.E., *et al.* (2021). *A temperature binning approach for multi-sector climate impact analysis*. Climatic Change 165. *https://doi.org/10.1007/s10584-021-03048-6*, (2) *Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,"* Docket ID No. EPA-HQ-OAR-2021-0317, September 2022, (3*) The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050*. Published by the U.S. Department of State and the U.S. Executive Office of the President, Washington DC. November 2021, (4) *Climate Risk Exposure: An Assessment of the Federal Government's Financial Risks to Climate Change*, White Paper, Office of Management and budget, April 2022.

rail and road infrastructure. While the FrEDI framework currently quantifies damages for 20 sectors within the U.S., it is important to note that it is still a preliminary and partial assessment of climate impacts relevant to U.S. interests in a number of ways. For example, FrEDI does not reflect increased damages that occur due to interactions between different sectors impacted by climate change or all the ways in which physical impacts of climate change occuring abroad have spillover effects in different regions of the U.S. See the FrEDI Technical Documentation[55] for more details.

These scientific assessments, EPA analyses, and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.

IV. State of the Electric Power Sector

A. Introduction

The electric power sector is experiencing a prolonged period of transition and structural change. As noted earlier in the *Executive Summary* (section I.B), since the generation of electricity from coal-fired power plants peaked nearly two decades ago, the power sector has undergone a dynamic transformation—and continues to change at a rapid pace. Today, natural gas-fired power plants provide the largest share of net generation, and as new technologies enter the marketplace, power producers continue to replace aging assets with more efficient and lower cost alternatives. This transition has been a driving force in sustained GHG emissions reductions across the sector.

[55] EPA. (2021). Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI). U.S. Environmental Protection Agency, EPA 430-R-21-004, available at *https://www.epa.gov/cira/fredi*.

This section of the preamble discusses recent trends in the electric power sector, beginning with background information on how electricity is generated and the role of EGUs in supplying electricity to consumers. This is followed with general information about the different types of EGUs providing power to the grid and the overall trends in generation with a focus on the coal- and natural gas-fired units that are the subject of these proposed rulemakings.

This section also includes a summary of the provisions and incentives included in recent Federal legislation that will impact the power sector as well as state actions and commitments by power producers to reduce GHG emissions. The section concludes with projections of future trends in power sector generation.

B. Background

1. Electric Power Sector

Electricity in the U.S. is generated by a range of technologies, and while the sector is rapidly evolving, the stationary combustion turbines and steam generating EGUs that are the subject of these proposed regulations still provide more than half of the electricity generated in the U.S. These EGUs fill many roles that are important to maintaining a reliable supply of electricity. For example, certain EGUs generate power on a round-the-clock basis to meet base load demand. Some providecomplementary generation to balance variable supply and demand resources, while others provide peaking capacity during hours of the highest daily, weekly, or seasonal demand.[56] Some EGUs also play important roles ensuring the reliability of the electric

[56] Generation and capacity are commonly reported statistics with key distinctions. Generation is the production of electricity and is a measure of an EGU's *actual* output while capacity is a measure of the maximum *potential* production of an EGU under certain conditions. There are several methods to calculate an EGU's capacity, which are suited for different applications of the statistic. Capacity is typically measured in megawatts (MW) for individual units or gigawatts (1 GW = 1,000 MW) for multiple EGUs. Generation is often measured in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (1 GWh = 1 million kWh).

grid, including ingfacilitate the regulation of frequency and voltage,providing "black start" capability in the event that the grid must be repowered after a widespread outage, and providing reserve generating capacity in the event of unexpected changes in the availability of other generators.

In general, the EGUs with the lowest operating costs are dispatched first, and, as a result, an inefficient EGU with high fuel costs will typically only operate if other lower-cost plants are unavailable or insufficient to meet demand. Units are also unavailable during both routine and unanticipated outages, which typically become more frequent as power plants age. These factors result in the mix of available generating capacity types (*e.g.*, the share of capacity of each type of generating source) being substantially different than the mix of the share of total electricity produced by each type of generating source in a given season or year.

Generated electricity must be transmitted over networks[57] of high voltage lines to substations where power is stepped down to a lower voltage for local distribution. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control

[57] The three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those parts of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf*.

of a single regional operator;[58] in others, individual utilities[59] coordinate the operations of their generation andtransmission to balance the system across their respective service territories. Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers.

During the past few decades, several jurisdictions in the U.S. began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities developed much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission-only utilities and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by utilities separately from the generation of electricity and sometimes separately from the purchase and sale of electricity. Power sector restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission services needed to deliver power to consumers. The resulting wholesale energy, capacity, and ancillary products markets are regulated by the Federal Energy Regulatory Commission (FERC).[60]

[58] For example, PJM Interconnection, LLC, Western Area Power Administration (which comprises four sub-regions).
[59] For example, Los Angeles Department of Power and Water, Florida Power and Light.
[60] The ERCOT (Electric Reliability Council of Texas) wholesale and retail energy market is not subject to FERC's authority.

2. Types of EGUs

In 2021, approximately 61 percent of net electricity was generated from the combustion of fossil fuels with natural gas providing 38 percent, coal providing 22 percent, and petroleum products such as fuel oil providing an additional 1 percent.[61] Fossil fuel-fired EGUs include the steam generating units and stationary combustion turbines that are the subject of these proposed regulations.

There are two forms of fossil fuel-fired electric utility steam generating units: utility boilers and those that use gasification technology (*i.e.*, integrated gasification combined cycle (IGCC) units). Fossil fuel-fired utility boilers include those that burn natural gas, oil, or coal; however, coal is the most common fuel for these types of EGUs. An IGCC unit gasifies fuel—typically coal or petroleum coke—to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power. The heat created by these technologies produces high-pressure steam that is released to rotate turbines, which, in turn, spin an electric generator.

Stationary combustion turbine EGUs (most commonly natural gas-fired) use one of two configurations: combined cycle or simple cycle combustion turbines. Combined cycle units have two generating components (*i.e.*, two cycles) operating from a single source of heat. Combined cycle units first generate power from a combustion turbine (*i.e.*, the combustion cycle)[62] directly from the heat of burning natural gas or other fuel. The second cycle reuses the waste heat from the combustion turbine engine, which is routed to a heat recovery steam generator (HRSG) that

[61] U.S. Energy Information Administration (EIA). *Electric Power Monthly, Table 1.1 and Form EIA-860M*, July 2022. Accessed at *https://www.eia.gov/electricity/data/php*.
[62] Note that natural gas can also be used as a fuel in a steam generating EGU (boiler) and many existing coal- and oil-fired utility boilers have repowered as natural gas-fired units.

generates steam, which is then used to produce additional power using a steam turbine (*i.e.*, the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Combined cycle units that fire mostly natural gas are commonly referred to as natural gas combined cycle (NGCC) units, and, with greater efficiency, are utilized at higher capacity factors to provide base load or intermediate power. An EGU's capacity factor indicates a power plant's electricity output as a percentage of its total generation capacity. Simple cycle combustion turbines only use a combustion turbine to produce electricity (*i.e.,* there is no heat recovery or steam cycle). These less-efficient combustion turbines are generally utilized at non-base load capacity factors and contribute to reliable operations of the grid during periods of peak demand, or provides flexibility to support increased generation from variable energy sources.

Other generating sources produce electricity by harnessing kinetic energy from flowing water, wind, or tides, thermal energy from geothermal wells, or solar energy primarily through photovoltaic solar arrays. Spurred by a combination of declining costs, consumer preferences and government policies, the capacity of these renewable technologies is growing, and when considered with existing nuclear energy, accounted for nearly 41 percent of the overall net electricity supply in 2022. Many projections show this share growing over time. For example, the EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case (*i.e.*, the EPA's projections of the power sector, which includes representation of the IRA absent further regulation) shows zero-emitting sources reaching 76 percent of electricity generation by 2040. (See section IV.F of this preamble and the accompanying Regulatory Impact Analysis for additional discussion of projections for the power sector).

C. Recent Changes in the Power Sector

1. Overview

For more than a decade, the utility power sector has experienced substantial transition and structural change, both in terms of the mix of generating capacity and in the share of electricity generation supplied by different types of EGUs. These changes are the result of multiple factors, including normal replacements of older EGUs; changes in electricity demand across the broader economy; growth and regional changes in the U.S. population; technological improvements in electricity generation from both existing and new EGUs; changes in the prices and availability of different fuels; state and federal policy; the preferences and purchasing behaviors of end-use electricity consumers; and substantial growth in electricity generation from renewable sources.

One of the most important developments of this transition has been the evolving economics of the power sector. Specifically, the existing fleet of coal-fired EGUs continues to age and become more costly to maintain and operate. At the same time, the supply and availability of natural gas has increased significantly, and its price has held relatively low. For the first time, in April 2015, natural gas surpassed coal in monthly net electricity generation and since that time has maintained its position as the primary fossil fuel for base load energy generation, for peaking applications, and for balancing renewable generation.[63] Additionally, there has been increased generation from investments in non-fossil fuel-based energy technologies spurred by technological advancements, declining costs, state and Federal policies,

[63] U.S. Energy Information Administration (EIA). Monthly Energy Review and Short-Term Energy Outlook, March 2016. Accessed at *https://www.eia.gov/todayinenergy/detail.php?id=25392#:~:text=Natural%20gas%20generation%20first%20surpassed,generation%20has%20evolved%20over%20time*.

and most recently, the Infrastructure Investment and Jobs Act (IIJA) and the IRA. For example, the IIJA provides investments and other policies to help commercialize, demonstrate, and deploy technologies such as small modular nuclear reactors, long-duration energy storage, regional clean hydrogen hubs, advanced geothermal systems, and advanced distributed energy resources (DER) as well as more traditional wind and solar resources. The IRA provides tax and other incentives to directly spur deployment of clean energy technologies. Particularly relevant to this proposal, the incentives in the IRA,[64] which are discussed in detail later in this section of the preamble, support the expansion of technologies, such as carbon capture and storage (CCS) and hydrogen technologies, that reduce GHG emissions from fossil-fired units.

The ongoing transition of the power sector is illustrated by a comparison of data between 2010 and 2021. In 2010, approximately 70 percent of the electricity provided to the U.S. grid was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share. By 2021, fossil fuel net generation was approximately 60 percent, less than the share in 2010 despite an increase in total electricity demand. Moreover, the share of fossil generation supplied by coal-fired EGUs fell from 46 percent in 2010 to 23 percent in 2021 while the share supplied by natural gas-fired EGUs rose from 23 to 37 percent during the same period. In absolute terms, coal-fired generation declined by 51 percent while natural gas-fired generation increased by 64 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing gas-fired EGUs. The combination of

[64] U.S. Department of Energy (DOE). August 2022. *The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals.* Accessed at *https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf*.

wind and solar generation also grew from 2 percent of the electric power sector mix in 2010 to 12 percent in 2021.[65]

The broad trends throughout the power sector can also be seen in the number of commitments and announced plans of many EGU owners and operators across the industry to decarbonize—spanning all types of companies in all locations. Moreover, state governments, which traditionally regulate investment decisions regarding electricity generation, have implemented their own policies to reduce GHG emissions from power generation.

Additional analysis of the utility power sector, including projections of future power sector behavior and the impacts of these proposed rules, is discussed in more detail in section XIV of this preamble, in the accompanying RIA, and in the technical support document (TSD), titled *Power Sector Trends*. The latter two documents are available in the rulemaking docket. Consistent with analyses done by other energy modelers, the RIA and TSD demonstrate that the sector trend of moving away from coal-fired generation is likely to continue and that non-emitting technologies may eventually displace certain natural gas-fired combustion turbines.

2. Trends in Coal-fired Generation

Coal-fired steam generating units have historically been the nation's foremost source of electricity, but coal-fired generation has declined steadily since its peak approximately 20 years ago. Construction of new coal-fired steam generating units was at its highest between 1967 and 1986, with approximately 188 GW (or 9.4 GW per year) of capacity added to the grid during that 20-year period.[66] The peak capacity addition was 14 GW, which was added in 1980. These coal-

[65] U.S. Energy Information Administration (EIA). *Annual Energy Review*, table 8.2b Electricity net generation: electric power sector. See *https://www.eia.gov/totalenergy/data/annual/.*
[66] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA-860M, Inventory of Operating Generators and Inventory of Retired Generators, March 2022. See *https://www.eia.gov/electricity/data/eia860m/.*

fired steam generating units operated as base load units for decades, providing the portion of electricity loads that are continually present and typically operate throughout most hours of the year. However, beginning in 2005, the U.S. power sector—and especially the coal-fired fleet—began experiencing a period of transition that continues today. Many of the older coal-fired steam generating units built in the 1960s, 1970s, and 1980s have retired and/or have experienced significant reductions in net generation due to cost pressures and other factors. Some of these coal-fired steam generating units repowered with combustion turbines and natural gas.[67] And with no new coal-fired steam generating units commencing construction in more than a decade, much of the fleet that remains is aging, expensive to operate and maintain, and increasingly uncompetitive relative to other sources of generation in many parts of the country.

Since 2010, the power sector's total installed capacity[68] has increased by 144 GW (14 percent), while coal-fired steam generating unit capacity has declined by 107 GW. This reduction in coal-fired steam generating unit capacity was offset by an increase in total installed wind capacity of 93 GW, natural gas capacity of 84 GW, and an increase in solar capacity of 60 GW during the same period. Additionally, significant amounts of DER solar (33 GW) were also added. These trends accelerated during the shorter 2015–2021 period when the power sector's total capacity (1,183 GW) increased by 10 percent (109 GW). The largest change in capacity was driven by a reduction of 70 GW of coal capacity. This was offset by a net increase of 60 GW of

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[67] U.S. Energy Information Administration (EIA). Today in Energy. *More than 100 coal-fired plants have been replaced or converted to natural gas since 2011*. August 2020. See *https://www.eia.gov/todayinenergy/detail.php?id=44636.*

[68] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and CHP facilities classified as Independent Power Producers (IPP) and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural gas information reflects data for all generating units using natural gas as the primary fossil heat source unless otherwise stated. This includes combined cycle, simple cycle, steam, and miscellaneous (< 1 percent).

wind capacity, 52 GW of natural gas capacity, and 47 GW of solar capacity. Additionally, 23 GW of DER solar were also added from 2015 to 2021.

At the end of 2021, there were approximately 212 GW of coal-fired capacity remaining in the U.S. Although much of the fleet of coal-fired steam generating units has historically operated as base load, there can be notable differences in design and operation across various facilities. For example, coal-fired steam generating units smaller than 100 MW comprise 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity.[69] Moreover, average annual capacity factors for coal-fired steam generating units have declined from 67 to 49 percent since 2010,[70] indicating that a larger share of units are operating in non-base load fashion, which requires increased cycling and can lead to less efficient fuel use, increased emission rates, and increased operation and maintenance costs.

Older power plants also tend to become uneconomic over time as they become more costly to maintain and operate,[71] especially when competing for dispatch against newer and more efficient generating technologies that have lower operating costs. Some of these competing technologies are often encouraged through Federal and state policies, such as subsidies and mandates that can further reduce their costs relative to coal. The average coal-fired power plant that retired between 2015 and 2021 was more than 50 years old, and 65 percent of the remaining

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[69] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v6. October 2022. See *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*.
[70] U.S. Energy Information Administration (EIA). Electric Power Annual 2021, table 1.2.
[71] U.S. Energy Information Administration (EIA). U.S. coal plant retirements linked to plants with higher operating costs. December 2019. See *https://www.eia.gov/todayinenergy/detail.php?id=42155*.

fleet of coal-fired steam generating units will be 50 years old or more within a decade.[72] To further illustrate this trend, the existing coal-fired steam generating units older than 40 years represent 71 percent (154 GW)[73] of the total remaining capacity. In fact, more than half (118 GW) of the coal-fired steam generating units still operating have already announced retirement dates prior to 2040.[74] As discussed further in this section, the IRA will accelerate this trend.

The reduction in coal-fired generation by electric utilities is also evident in data for annual U.S. coal production, which reflects reductions in international demand as well. In 2008, annual coal production peaked at nearly 1,200 million short tons (MMst) followed by sharp declines in 2015 and 2020. In 2015, less than 800 MMst were produced, and in 2020, the total dropped to 535 MMst, the lowest output since 1965.

3. Trends in Natural Gas-fired Generation

In the lower 48 states, most combustion turbine EGUs burn natural gas, and some have the capability to fire distillate oil as backup for periods when natural gas is not available, such as when residential demand for natural gas is high during the winter. Areas of the country without access to natural gas often use distillate oil or some other locally available fuel. Combustion turbines have the capability to burn either gaseous or liquid fossil fuels, including but not limited to kerosene, naptha, synthetic gas, biogases, liquified natural gas (LNG), and hydrogen.

[72] eGRID 2020 (January 2022 release from EPA eGRID website). Represents data from generators that came online between 1950 and 2020 (inclusive); a 71-year period. Full eGRID data includes generators that came online as far back as 1915.
[73] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form-860M, Inventory of Operating Generators and Inventory of Retired Generators. August 2022. See *https://www.eia.gov/electricity/data/eia860m/*.
[74] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v6. October 2022. See *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*.

Natural gas consists primarily of methane and can be derived from multiple sources. After the raw gas is extracted from the ground, it is processed to remove impurities and to separate methane from other gases and natural gas liquids to produce pipeline quality gas.[75] This gas is sent to intermediate storage facilities prior to being piped through transmission feeder lines to a distribution network on its path to storage facilities or end users. During the past 20 years, advances in hydraulic fracturing (*i.e.*, fracking) and horizontal drilling techniques have opened new regions of the U.S. to gas exploration.

According to the U.S. Energy Information Administration (EIA), annual natural gas marketed production in the U.S. remained consistent at approximately 20 trillion cubic feet (Tcf) from the 1970s to the early 2000s. However, since 2005, annual natural gas marketed production has steadily increased and approached 35 Tcf in 2021, which is an average of approximately 94.6 billion cubic feet per day.[76] Thirty-four states produce natural gas with Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7 percent) accounting for approximately 70 percent of total production. Natural gas production exceeded consumption in the U.S. for the first time in 2017.

As the production of natural gas has increased, the annual average price has declined during the same period.[77] In 2008, U.S. natural gas prices peaked at $13.39 per million British thermal units ($/MMBtu) for residential customers. By 2020, the price was $10.45/MMBtu. The

[75] Center for Climate and Energy Solutions (C2ES). *Natural Gas*. See *https://www.c2es.org/content/natural-gas/*.
[76] U.S. Energy Information Administration (EIA). Natural gas explained. Where our natural gas comes from. See *https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php#:~:text=The%20United%20States%20now%20produces,the%20highest%20annual%20amount%20recorded*.
[77] U.S. Energy Information Administration (EIA). *Natural Gas Annual*, September 2021. See *https://www.eia.gov/energyexplained/natural-gas/prices.php*.

decrease in average annual natural gas prices can also been seen in city gate prices (*i.e.*, a point or measuring station where natural gas is transferred from long-distance pipelines to a local distribution company), which peaked in 2008 at $8.85/MMBtu. By 2020, city gate prices were $3.30/MMBtu. An equivalent $/MMBtu basis is a common way to compare natural gas and coal fuel prices. For example, the price of Henry Hub natural gas in July 2022 was $7.39/MMBtu while the spot price of Central Appalachian coal was $7.25/MMBtu for the same month. However, this method of fuel price comparison based on equivalent energy content does not reflect differences in energy conversion efficiency (*i.e.*, heat rate) and other factors among different types of generators. Because natural gas-fired combustion turbines are more efficient than coal-fired steam units, any fuel cost comparison should include an efficiency basis (dollar per megawatt-hour) to the equivalent energy content. For illustrative purposes, an EIA comparison based on this method showed that the Henry Hub natural gas price in July 2022 was $59.18/MWh and the price for Central Appalachian coal was $78.25/MWh for the same month.[78]

There has been significant expansion of the natural gas-fired EGU fleet since 2000, coinciding with efficiency improvements of combustion turbine technologies, increased availability of natural gas, increased demand for flexible generation to support the expanding capacity of renewable energy resources, and declining costs for all three elements. According to data from EIA, annual capacity additions for natural gas-fired EGUs peaked between 2000 and 2006, with more than 212 GW added to the grid during this period. Of this total, approximately

[78] U.S. Energy Information Administration (EIA). *Electric Monthly Update*. September 23. 2022. Report derived from Bloomberg Energy. EIA notes that the competition between coal and natural gas to produce electricity is complex, involving delivered prices and emission costs, the terms of fuel supply contracts, and the workings of fuel markets.

147 GW (70 percent) were combined cycle capacity and 65 GW were simple cycle capacity.[79] From 2007 to 2021, more than 125 GW of capacity were constructed and approximately 78 percent of that total were combined cycle EGUs. This figure represents an average of almost 4.2 GW of new combustion turbine generation capacity per year. In 2021, the net summer capacity of combustion turbine EGUs totaled 413 GW, with 281 GW being combined cycle generation and 132 GW being simple cycle generation.

This trend away from coal to natural gas is also reflected in comparisons of annual capacity factors, sizes, and ages of affected EGUs. For example, the annual average capacity factors for natural gas-fired units increased from 28 to 37 percent between 2010 and 2021. And compared with the fleet of coal-fired steam generating units, the natural gas fleet is generally smaller and newer. While 67 percent of the coal-fired steam generating unit fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit. In terms of the age of the generating units, nearly 50 percent of the natural gas capacity has been in service less than 15 years.[80]

As explained in greater detail later in this preamble and in the accompanying RIA, future capacity projections for natural gas-fired combustion turbines[81] differ from those highlighted in recent historical trends. The largest source of new generation is from renewable energy and most projections show that the total installed capacities of natural gas-fired combustion turbines are

[79] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA-860M, Inventory of Operating Generators and Inventory of Retired Generators, July 2022. See *https://www.eia.gov/electricity/data/eia860m/.*
[80] National Electric Energy Data System (NEEDS) v.6.
[81] U.S. Department of Energy (DOE). August 2022. *The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals.* Accessed at *https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf.*

likely to decline after 2030 in response to increased generation from renewables, energy storage, and other technologies. Nearly 80 percent of capacity additions in 2022 were from non-emitting generation resources including solar, wind, nuclear, and energy storage.[82] The IRA is likely to accelerate this trend.

4. Trends in Renewable Generation

Renewable sources of electric generation—especially solar and wind—have expanded in the U.S. during the past decade. This growth has coincided with a reduction in the costs of the technologies, supportive state and Federal policies, and increased consumer demand for low-GHG electricity. In 2021, renewable energy sources produced approximately 20 percent of the nation's net generation, led by wind (9.2 percent), hydroelectric (6.3 percent), solar (2.8 percent), and other sources such as geothermal and biomass (1.7 percent).[83]

The costs of renewable energy sources have fallen over time due to technological advances, improvements in performance, increased demand for clean energy, as well as local, state, and Federal incentives and tax credits. For example, the unsubsidized average levelized cost of wind energy from 1988 to 1999 was $106/MWh and has since declined to $32/MWh in 2021.[84] The average levelized cost of energy for utility-scale solar photovoltaics has fallen from $227/MWh in 2010 to $33/MWh in 2021.[85] And the National Renewable Energy Laboratory

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[82] U.S. Energy Information Administration (EIA). Today in Energy. *Solar power will account for nearly half of new U.S. electric generating capacity in 2022*. January 2022. See *https://www.eia.gov/todayinenergy/detail.php?id=50818*.
[83] U.S. Energy Information Administration (EIA). Monthly Energy Review, table 7.2B Electricity Net Generation: Electric Power Sector, May 2022. See *https://www.eia.gov/totalenergy/data/monthly/*.
[84] U.S. Department of Energy (DOE), Land-Based Wind Market Report: 2022 Edition, 2022. See *https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition*.
[85] Lawrence Berkeley National Laboratory (LBNL), Utility-Scale Solar Technical Brief, 2022 Edition, September 2022. See *https://emp.lbl.gov/utility-scale-solar*.

(NREL) has documented cost decreases of 64, 69, and 82 percent, respectively, for residential-, commercial-, and utility-scale solar installations since 2010.[86]

During the past 15 years, more than 122 GW of wind (primarily onshore) and 61 GW of solar capacity have been constructed, which represent a tripling of wind capacity and a 20-fold increase in solar capacity.[87] Prior to 2007, no more than 2.6 GW of new wind capacity was built in any year, and the wind capacity added from 2000 to 2006 averaged 1.2 GW per year. In 2007, the nation added 5.3 GW of total wind capacity and the annual average was 7.2 GW through 2019. Wind capacity additions peaked in the past 2 years at a total of nearly 29 GW. For solar, the pattern of expansion is similar. For example, from 2000 to 2006, a total of 11 MW of new solar capacity was constructed, and from 2007 to 2011, total capacity additions increased to 1.2 GW. However, from 2012 to 2019, more than 36 GW of solar capacity was built (an average of 4.5 GW per year). And in 2020 and 2021, new solar capacity totaled of 24 GW. In terms of the net operating share of summer capacity in 2021, wind produced 46 percent of all renewable energy while solar generated 21 percent. The remaining electricity generated from renewables included 28 percent from hydroelectric and 5 percent from other sources that include geothermal systems, biogases/biomethane from landfills, woody materials and other biomass, and municipal solid waste.

There are also emerging technologies that have demonstrated the ability to further support the development and integration of renewable energy. At the end of 2021, there were 331 large-scale battery storage systems operating in the U.S. with a combined capacity of 4.8

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[86] *https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html*.

[87] U.S. Energy Information Administration (EIA), Electric Generators Inventory, Form-860M, Inventory of Operating Generators and Inventory of Retired Generators, July 2022. See *https://www.eia.gov/electricity/data/eia860m/*.

GW (10.7 GWh).[88] In terms of small-scale battery storage, there were 781 MW of reported capacity in 2021, mostly in California.[89] Energy storage costs have declined 72 percent since 2015, and in 2019, the capital costs were $589/kWh.[90] Declining costs have led to additional capacity being installed at each facility, and this increases the duration of each system when operating at maximum output. With 20.8 GW of grid storage already announced for 2023–2025, EIA expects that capacity will more than triple from 7.8 GW in late 2022 to approximately 30 GW by the end of 2025.[91]

5. Trends in Nuclear Generation

The U.S. power sector continues to rely on nuclear sources of energy for a consistent portion of net generation. Since 1990, nuclear energy has provided about 20 percent of the nation's electricity, and 92 reactors were operating at 54 nuclear power plants in 28 states in 2022.[92]

It should be noted that despite the consistent output from nuclear power plants over time, the number of operating reactors is beginning to decline. The average retirement age for a nuclear reactor is 42 years and the average age of the remaining nuclear fleet is currently 40 years, although age is only one consideration for determining when a nuclear plant may retire.

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[88] U.S. Energy Information Administration (EIA). Annual Electric Generator Report, 2021 Form EIA-860. See *https://www.eia.gov/electricity/data/eia860/*.
[89] U.S. Energy Information Administration (EIA). Annual Electric Power Industry Report, 2021 Form EIA-861. See *https://www.eia.gov/electricity/data/eia861/*.
[90] U.S. Energy Information Administration (EIA). Annual Electric Generator Report, 2019 Form EIA-860. See *https://www.eia.gov/analysis/studies/electricity/batterystorage/*.
[91] U.S. Energy Information Administration (EIA). Today in Energy. *U.S. battery storage capacity will increase significantly by 2025*. December 2022. See *https://www.eia.gov/todayinenergy/detail.php?id=54939*.
[92] U.S. Energy Information Administration (EIA). *Electric Generators Inventory, Form-860M, Inventory of Operating Generators and Inventory of Retired Generators*. August 2022. See *https://www.eia.gov/electricity/data/eia860m/*.

For example, nuclear generating units at Dominion Generation's Surry plants applied to the Nuclear Regulatory Commission (NRC) for a second 20-year license renewal and were granted the extension to operate for an additional 20-year interval; extending the life of Surry, Units 1 and 2, well past the 40-year average. Others who have applied to the NRC for a second 20-year license renewal include Dominion Generation for North Anna Units 1 and 2; NextEra Energy for Point Beach Units 1 and 2; Duke Energy Carolinas for Oconee Units 1, 2, and 3; Florida Power & Light Company for St. Lucie Units 1 and 2; and Northern States Power Company – Minnesota for Monticello. If granted, these additional plants' licenses would also be extended well past the 40-year average. Recent state and federal policies, including the Department of Energy's $6 billion Civilian Nuclear Credit program enacted by IIJA and the 45U tax credit (discussed more below) are intended to forestall the closure of existing nuclear power plants that would otherwise close for economic reasons.

There is also interest in the next generation of nuclear technologies. Small modular nuclear reactors, which can provide both firm dispatchable power and load-following capabilities to balance greater volumes of intermittent renewable generation, could play a role in future energy generation. On January 19, 2023, the NRC issued a final rule certifying the first small modular reactor design. Expectations with respect to output from advanced nuclear generation vary, from negligible on the low end to as high as between 1,400 and 3,600 terawatt-hours per year (TWh/yr) by 2050.[93] According to one survey by the Nuclear Energy Institute, utilities are considering building more than 90 GW of small modular nuclear reactors.[94]

D. GHG Emissions from Fossil Fuel-fired EGUs

The principal GHGs that accumulate in the Earth's atmosphere above pre-industrial levels because of human activity are CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Of these, CO_2 is the most abundant, accounting for 80 percent of all GHGs present in the atmosphere. This abundance of CO_2 is largely due to the combustion of fossil fuels by the transportation, electricity, and industrial sectors.[95]

The amount of CO_2 emitted from fossil fuel-fired EGUs depends on the carbon content of the fuel and the size and efficiency of the EGU. Different fuels emit different amounts of CO_2 in relation to the energy they produce when combusted. The amount of CO_2 produced when a fuel is burned is a function of the carbon content of the fuel. The heat content, or the amount of energy produced when a fuel is burned, is mainly determined by the carbon and hydrogen content of the fuel. For example, in terms of pounds of CO_2 emitted per million British thermal units of energy produced, when combusted, natural gas is the lowest compared to other fossil

[93] Stein, A., Messinger, J., Wang, S., Lloyd, J., McBride, J., Franovich, R. (July 6, 2022). "*Advancing Nuclear Energy: Evaluating Deployment, Investment, and Impact in America's Clean Energy Future*." Breakthrough Institute. See *https://thebreakthrough.imgix.net/Advancing-Nuclear-Energy_v3-compressed.pdf*.
[94] Derr, E. (July 29, 2022). *Energy Studies and Models Show Advanced Nuclear as the Backbone of Our Carbon-Free Future*. Nuclear Energy Institute (NEI). See *https://www.nei.org/news/2022/studies-and-models-show-demand-for-adv-nuclear*.
[95] U.S. Environmental Protection Agency (EPA). Overview of greenhouse gas emissions. July 2021. See *https://www.epa.gov/ghgemissions/overview-greenhouse-gases#carbon-dioxide*.

fuels at 117 lb CO_2/MMBtu.[96] [97] The average for coal is 216 lb CO_2/MMBtu, but varies between 206 to 229 lb CO_2/MMBtu by type (*e.g.*, anthracite, lignite, subbituminous, and bituminous).[98] The value for petroleum products such as diesel fuel and heating oil is 161 lb CO_2/MMBtu.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks[99] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It presents total U.S. anthropogenic emissions and sinks[100] of GHGs, including CO_2 emissions, for the years 1990–2020.

According to the latest inventory, in 2020, total U.S. GHG emissions were 5,981 million metric tons of carbon dioxide equivalent (MMT CO_2e). The transportation sector (27.2 percent) was the largest contributor to total U.S. GHG emissions, followed by the power sector (24.8 percent) and industrial sources (23.8 percent). In terms of annual CO_2 emissions, the power sector was responsible for 30.5 percent (1,439 MMT CO_2e) of the nation's 2020 total.

[96] Natural gas is primarily CH_4, which has a higher hydrogen to carbon atomic ration, relative to other fuels, and thus, produces the least CO_2 per unit of heat released. In addition to a lower CO_2 emission rate on a lb/MMBtu basis, natural gas is generally converted to electricity more efficiently than coal. According to EIA, the 2020 emissions rate for coal and natural gas were 2.23 lb CO_2/kWh and 0.91 lb CO_2/kWh, respectively. See *www.eia.gov/tools/faqs/faq.php?id=74&t=11*.

[97] Values reflect the carbon content on a per unit of energy produced on a higher heating value (HHV) combustion basis and are not reflective of recovered useful energy from any particular technology.

[98] Energy Information Administration (EIA). *Carbon Dioxide Emissions Coefficients.* See *https://www.eia.gov/environment/emissions/co2_vol_mass.php*.

[99] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020*. See *https://cfpub.epa.gov/ghgdata/inventoryexplorer/#allsectors/allsectors/allgas/econsect/all*.

[100] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep-sea reservoirs of carbon dioxide.

CO_2 emissions from the power sector have declined by 40 percent since 2005 (when the power sector reached annual emissions of 2,400 MMT CO_2, its historical peak to date).[101] The reduction in CO_2 emissions can be attributed to the power sector's ongoing trends away from carbon-intensive coal-fired generation and toward more natural gas-fired and renewable sources. In 2005, CO_2 emissions from coal-fired EGUs alone measured 1,983 MMT.[102] This total dropped to 1,351 MMT in 2015 and reached 974 MMT in 2019, the first time since 1978 that coal-fired CO_2 emissions were below 1,000 MMT. In 2020, emissions of CO_2 from coal-fired EGUs measured 788 MMT before rebounding in 2021 to 909 MMT due to increased demand. By contrast, CO_2 emissions from natural gas-fired generation have almost doubled since 2005, increasing from 319 MMT to 613 MMT in 2021, and CO_2 emissions from petroleum products (*i.e.*, distillate fuel oil, petroleum coke, and residual fuel oil) declined from 98 MMT in 2005 to 18 MMT in 2021.

When the EPA finalized the Clean Power Plan (CPP) in October 2015, the Agency projected that, as a result of the CPP, the power sector would reduce its annual CO_2 emissions to 1,632 MMT by 2030, or 32 percent below 2005 levels (2,400 MMT).[103] Instead, even in the absence of Federal regulations for existing EGUs, annual CO_2 emissions from sources covered by the CPP had fallen to 1,540 MMT by the end of 2021, a nearly 36 percent reduction below 2005 levels. The power sector achieved a deeper level of reductions than forecast under the CPP

[101] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020*. See *https://cfpub.epa.gov/ghgdata/inventoryexplorer/#electricitygeneration/entiresector/allgas/category/all*.
[102] U.S. Energy Information Administration (EIA). Monthly Energy Review, table 11.6. September 2022. See *https://www.eia.gov/totalenergy/data/monthly/pdf/sec11.pdf*.
[103] See 80 FR 63662 (October 23, 2015). Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

and approximately a decade ahead of time. By the end of 2015, several months after the CPP was finalized, those sources already had achieved CO_2 emission levels of 1,900 MMT, or approximately 21 percent below 2005 levels. These trends have continued and demonstrate that states and utilities will continue to achieve additional CO_2 reductions. These changes have been influenced by both market pressures and policy reasons. For example, in addition to state GHG reduction programs there are renewable portfolio standards (RPS) and federal and state tax incentives. However, progress in emission reductions is not uniform across all states and so federal policies play an essential role. As discussed earlier in this section, the power sector remains a leading emitter of CO_2 in the U.S., and, despite the emission reductions since 2005, current CO_2 levels continue to endanger human health and welfare. Further, as sources in other sectors of the economy turn to electrification to decarbonize, future CO_2 reductions from fossil fuel-fired EGUs have the potential to take on added significance and increased benefits.

E. Drivers for Ongoing Change

1. Recent Legislation Impacting the Power Sector

On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act (IIJA)[104] (also known as the Bipartisan Infrastructure Law), which allocated more than $70 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-carbon fuels. Some of the IIJA programs[105] that will impact the utility power sector include: $16.5 billion to

[104] See *https://www.congress.gov/bill/117th-congress/house-bill/3684/text*.
[105] See *https://gfoaorg.cdn.prismic.io/gfoaorg/0727aa5a-308f-4ef0-addf-140fd43acfb5_BUILDING-A-BETTER-AMERICA-V2.pdf*.

build and upgrade the nation's electric grid; $6 billion in financial support for existing nuclear reactors that are at risk of closing and being replaced by high-emitting resources; and more than $700 million for upgrades to the existing hydroelectric fleet. The IIJA established the Carbon Dioxide Transportation Infrastructure Finance and Innovation Program to provide flexible Federal loans and grants for building carbon dioxide pipelines designed with excess capacity, enabling integrated carbon capture and geologic storage. The IIJA also allocated $21.5 billion to fund new programs to support the development, demonstration, and deployment of clean energy technologies, such as $8 billion for the development of regional clean hydrogen hubs. Other clean energy technologies with IIJA funding include carbon capture, geologic sequestration, direct air capture, grid-scale energy storage, and advanced nuclear reactors. States, tribes, local communities, utilities, and others are eligible to receive funding.

The IRA, which President Biden signed on August 16, 2022,[106] has the potential for even greater impacts on the electric power sector. With an estimated $369 billion in Energy Security and Climate Change programs over the next 10 years, covering grant funding and tax incentives, the IRA provides investment toward non GHG-emitting generation and away from the fossil fuel-fired units that are the subjects of these proposed regulations. For example, one of the conditions set by Congress for the expiration of the Clean Electricity Production Tax Credits of the IRA, found in section 13701, is a 75 percent reduction in GHG emissions from the power sector below 2022 levels. The IRA also contains the Low Emission Electricity Program (LEEP) with funding provided to the EPA with the objective to reduce GHG emissions from domestic electricity generation and use through promotion of incentives, tools to facilitate action, and use of CAA regulatory authority. In particular, CAA section 135, added by IRA section 60107,

[106] See *https://www.congress.gov/bill/117th-congress/house-bill/5376/text*.

requires the EPA to conduct an assessment of the GHG emission reductions expected to occur from changes in domestic electricity generation and use through fiscal year 2031 and, further, provides the EPA $18 million "to ensure that reductions in [GHG] emissions are achieved through use of the existing authorities of [the Clean Air Act], incorporating the assessment…." CAA section 135(a)(6).

The IRA's provisions also demonstrate an intent to support development and deployment of low-GHG emitting technologies in the power sector through a broad array of additional tax credits, loan guarantees, and public investment programs. These provisions are aimed at reducing emissions of GHGs from new and existing generating assets, with tax credits for carbon capture, utilization, and storage (CCUS) and clean hydrogen production providing a pathway for the use of coal and natural gas as part of a low-carbon electricity grid. Finally, with provisions such as the Methane Emissions Reduction Program, Congress demonstrated a focus on the importance of actions to address methane emissions from petroleum and natural gas systems.

To assist states and utilities in their decarbonizing efforts, and most germane to this proposed rulemaking, the IRA increased the tax credit incentives for capturing and storing CO_2, including from industrial sources, including coal-fired steam generating units and natural gas-fired stationary combustion turbines. The increase in credit values, found in section 13104 (which revises Internal Revenue Code (IRC) section 45Q), is 70 percent, equaling $85/metric ton for CO_2 captured and securely stored in geologic formations and $60/metric ton for CO_2 captured and utilized or securely stored secure incidental storage in conjunction with enhanced oil recovery (EOR).[107] The CCUS incentives include 12 years of credits that can be claimed at the higher credit value beginning in 2023 for qualifying projects. These incentives will significantly

[107] See *https://www.democrats.senate.gov/imo/media/doc/inflation_reduction_act_of_2022.pdf.*

cut costs and are expected to accelerate the adoption of CCS in the utility power and other industrial sectors. Specifically for the power sector, the IRA requires that a qualifying carbon capture facility have a CO_2 capture design capacity of not less than 75 percent of the baseline CO_2 production of the unit and that construction must begin before January 1, 2033. The magnitude of this incentive is driving investment and announcements, evidenced by the increased number of permit applications for geologic sequestration.

The new provisions in section 13204 (IRC section 45V) codify production tax credits for 'clean hydrogen' as defined in the provision. The value of the credits earned by a project is tiered (four different tiers) and depends on the estimated GHG emissions of the hydrogen production process from well-to-gate. The credits range from \$3/kg H_2 for 0.0 to 0.45 kilograms of CO_2-equivalent emitted per kilogram of low-GHG hydrogen produced (kg CO_2e/kg H_2) down to \$0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2 (assuming wage and apprenticeship requirements are met). Projects with GHG emissions greater than 4.0 kg CO_2e/kg H_2 are not eligible. According to the DOE, current costs for hydrogen produced from renewable energy are around \$5/kg H_2.[108]

The clean hydrogen production tax credit is expected to incentivize the production of low-GHG hydrogen and ultimately exert downward pressure on costs.[109] Low-cost and widely available low-GHG hydrogen has the potential to become a material decarbonization lever in the power sector as the use of low-GHG hydrogen in stationary combustion turbines reduces direct GHG emissions as hydrogen releases no CO_2 when combusted. The tiered eligibility

[108] U.S. Department of Energy (DOE). Hydrogen and Fuel Cell Technologies Office. Hydrogen Shot. See *https://www.energy.gov/eere/fuelcells/hydrogen-shot*.
[109] Larsen, J., King, B., Kolus, H., Dasari, N., Hiltbrand, G., Herndon, W. (August 12, 2022). *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act*. Rhodium Group. See *https://rhg.com/research/climate-clean-energy-inflation-reduction-act/*.

requirements for the clean hydrogen production tax credit also incentivize the lowest-GHG emissions production processes.

Both 45Q and 45V are eligible for additional provisions that increase the value and usability of the credits. Certain tax-exempt entities, such as electric co-ops, may use direct pay for the full 12 or 10 year lifetime of the credits to monetize the credits directly as cash refunds rather than through tax equity transactions. Tax-paying entities may elect to have direct payment of 45Q or 45V credits for five consecutive years. Tax-paying entities may also elect to transfer credits to unrelated taxpayers, enabling direct monetization of the credits again without relying on tax equity transactions.The production tax credit is not the only provision in the IRA designed to incentivize low-GHG hydrogen. Projects may also access the investment tax credit (ITC) under IRC section 48 and may apply under IRC section 48C as energy storage property. Projects may not, however, combine credits from IRC section 45V with credits in IRC sections 45Q, or 48C. Hydrogen production tax credits became available in January 2023 for eligible new projects. Entities that commence construction between 2023 and 2032 can claim credits for the first 10 years of production.

The magnitude of this incentive—combined with those in the IIJA such as the $8 billion for regional hydrogen hubs and $1.5 billion for electrolyzer advancement—should accelerate the production of low-GHG hydrogen for use in a broad range of applications across many sectors, including the utility power sector.

Many of the IRA tax credit incentives are directed toward non-fossil fuel-based electric generation. They are designed to lower costs and market barriers to bring new zero-emitting generation and energy storage capacity online, to retain existing zero-emitting generators, and the energy efficiency tax credits are designed to reduce electricity demand. These financial tools have been used historically and shown to be a principal driver, buttressed by state renewable and clean energy standards, for incentivizing renewable deployment.[110] [111]

For example, the IRA expanded and extended the existing section 13101 (IRC section 45) production tax credits for new solar, wind, geothermal, and other eligible renewable or low-GHG emissions energy sources. The production tax credit (PTC) provides credits in a 10-year stream for each MWh of clean energy produced. The IRA indexed the PTC on inflation, increasing the credit amount to $27.50/MWh. For context, the energy price in the nation's largest wholesale energy market, PJM,[112] is typically between $20/MWh and $90/MWh depending on timing, load, and transmission congestion.

In parallel, the existing investment tax credits in section 13101 (IRC section 48) were also expanded and extended in the IRA. Taxpayers must elect between the ITC and the PTC for each applicable project. The ITC enables taxpayers to recoup up to 30 percent of project costs for technologies such as solar, geothermal, fiberoptic solar, fuel cells, microturbines, small wind, offshore wind, combined heat and power (CHP), and waste energy recovery. The IRA expanded eligibility to include storage technologies like batteries or hydrogen production-related property, which is considered a form of energy storage, as well as some non-storage technologies.

The IRA also tied the availability of power sector tax credits explicitly to reductions of GHG emissions from the power sector. Section 13701 and 13702 enacted a technology-neutral production and investment tax credit respectively for projects placed in service after 2025, which

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[110] *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions,* National Renewable Energy Laboratory (NREL), February 2016.
[111] *A Retrospective Assessment of Clean Energy Investments in the Recovery Act*, February 2016, U.S. Executive Office of the President, Memorandum.
[112] PJM Interconnection LLC (PJM) is a regional transmission organization (RTO serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia).

have greenhouse gas emissions rates of zero or less. These credits are available until the phaseout is triggered when power sectors GHG emissions fall below 25% of 2022 levels. Following state practices, Congress also included a zero-emission nuclear power production credit in the IRA to ensure existing in-service nuclear generators are retained for their contribution to base load zero-carbon emitting electricity. When labor and apprenticeship requirements are met, the credit price is $15/MWh. The credit amount declines when power prices rise above $25/MWh. The program begins in 2024 with credit streams available for nine years. This PTC is complementary to the $6 billion for nuclear advancements the IIJA authorized and appropriated to the Department of Energy (DOE). New nuclear plants would be eligible for either the technology-neutral Clean Electricity Production or Investment Credit (IRC section 45Y and 48E).

In the evaluation of these proposed actions, many of the technologies that receive investment under recent Federal legislation are not directly considered, as the EPA has not evaluated new generation technologies entities could employ in its assessment of the BSER. As the discussion of that assessment will make clear later in this preamble, the EPA's inquiry has focused on "measures that improve the pollution performance of individual sources."[113] It is important to understand, however, that many utilities and other power producers may opt to move from higher cost and higher emitting generating assets to technologies that are both lower cost and lower emitting both for business reasons and as a response to the requirements in these proposed rulemakings.

The following section (section IV.E.2.) includes a review of integrated resource plans (IRPs) filed by public utilities that prioritize GHG reductions. These IRPs demonstrate that most power companies intend to meet their GHG reduction targets by retiring aging coal-fired steam

[113] *West Virginia v. EPA*, 142 S. Ct. 2587, 2615 (2022).

generating EGUs and replacing them with a combination of renewable resources, energy storage, other non-emitting technologies, and natural gas-fired combustion turbines. Many IRPs further demonstrate the realization of power companies that to meet their GHG reduction targets, their natural gas-fired assets will need to occupy a much smaller GHG footprint through a combination of hydrogen, CCS, and reduced utilization. The IRA is designed to encourage this trend. For example, in addition to the provisions outlined above, including the 10 percent bonus value applied in 'energy communities' that include fossil-related properties, the IRA created grant and loan funding sources for hard-to-abate energy assets. Section 22004 of the IRA authorizes $9.7 billion in financing for rural electric co-operatives and providers to invest in cleaner technologies to achieve GHG reductions across rural electric systems while buttressing resilience and reliability. Additionally, Section 50144 of the IRA, known as the Energy Infrastructure Reinvestment Financing provision, provides $5 billion for backing $250 billion in low-cost loans for utilities to repower, repurpose, or replace energy infrastructure that has ceased operations, or to enable operating energy infrastructure to reduce air pollution or greenhouse gas emissions, . The financing in this provision enables a utility to repurpose an existing fossil site, such as a retired coal-fired power plant, or add CCUS or hydrogen capability to an operating coal or natural gas fired power plant, and retain community jobs while reducing GHG emissions.

2. Commitments by Utilities to Reduce GHG Emissions

The broad trends away from coal-fired generation and toward lower-emitting generation are reflected in the recent actions and announced plans of many utilities across the industry. As highlighted later in this section, through planning documents, IRPs, filings with state and local public utility commissions, and news releases, many utilities have made public commitments to move toward cleaner energy generation. Many utilities and other power generators have announced plans to increase their renewable energy holdings and continue reducing GHG emissions, regardless of any potential Federal regulatory requirements. For example, 50 power producers that are members of the Edison Electric Institute (EEI) have announced CO_2 reduction goals, two-thirds of which include net-zero carbon emissions by 2050.[114] This trend is not unique to the largest owner-operators of coal-fired EGUs; smaller utilities, public power cooperatives, and municipal entities are also contributing to these changes.

Some of the largest electric utilities that have publicly announced near- and long-term GHG reduction commitments, many with emission reduction targets of at least 80 percent (relative to 2005 levels unless otherwise noted), include:

- Xcel Energy: 80 percent reduction in CO_2 emissions by 2030 and 100 percent carbon-free by 2050. This includes a commitment to close or repower all remaining coal-fired EGUs by 2030.[115]
- DTE Energy: 65 percent reduction in CO_2 emissions by 2028, 90 percent reduction by 2040, and net-zero carbon emissions by 2050.[116]

[114] See Comments of Edison Electric Institute to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Docket ID No. EPA-HQ-OAR-2022-0723, November 18, 2022 ("Fifty EEI members have announced forward-looking carbon reduction goals, two-third of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals.").

[115] Xcel Energy is based in Minnesota with operations in Colorado, Michigan, New Mexico, North Dakota, South Dakota, Texas, and Wisconsin. See *2018 Integrated Resource Plan* at *https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/2018-SPS-NM-Integrated-Resource-Plan.pdf*.

[116] DTE Energy is based in Michigan. See *Our Bold Goal for Michigan's Clean Energy Future* at *https://dtecleanenergy.com/*.

- Ameren Energy: 60 percent reduction in CO_2 by 2030, 85 percent reduction by 2040, and net-zero carbon emissions by 2045.[117]
- Consumers Energy: 60 percent reduction in CO_2 by 2025 and net-zero carbon emissions by 2040. This includes the retirement of all coal-fired units by 2025.[118]
- Southern Company: 50 percent reduction in CO_2 by 2030 (relative to 2007 levels) and net-zero carbon emissions by 2050.[119]
- Duke Energy: 70 percent reduction in CO_2 by 2030 and net-zero carbon emissions by 2050. All coal-fired units will retire by 2035.[120]
- Minnesota Power (Allete Inc.): 70 percent renewable energy by 2030, 80 percent reduction in CO_2 and coal-free by 2035, and 100 percent carbon-free by 2050.[121]
- First Energy: 30 percent reduction in CO_2 (relative to 2019 levels) and net-zero carbon emissions by 2050.[122]

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[117] Ameren is based in Illinois and Missouri. See *2022 Integrated Resource Plan* at *https://www.ameren.com/missouri/company/environment-and-sustainability/integrated-resource-plan*.
[118] Consumers Energy is based in Michigan. See *Integrated Resource Plan* at *https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/2021-Integrated-Resource-Plan.pdf*.
[119] Southern Company is based in Georgia with operations in Alabama and Mississippi. See *https://www.southerncompany.com/sustainability/net-zero-and-environmental-priorities/net-zero-transition.html*.
[120] Duke Energy is based in North Carolina with operations in South Carolina, Florida, Indiana, Ohio, and Kentucky. See *NC IRP Fact Sheet* at *https://p-scapi.duke-energy.com/-/media/pdfs/our-company/202296-nc-irp-fact-sheet.pdf*.
[121] Allete Energy is based in Minnesota with operations in Wisconsin and North Dakota. See *Integrated Resource Plan* at: *https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b70795F77-0000-C41E-A71C-FD089119967C%7d&documentTitle=20212-170583-01*.
[122] First Energy is based in Ohio with operations in Pennsylvania, West Virginia, and New Jersey. See *https://www.firstenergycorp.com/content/dam/environmental/files/climate-strategy.pdf*.

- American Electric Power: 80 percent reduction in CO_2 by 2030 and net-zero carbon emissions by 2045.[123]
- Alliant Energy: 50 percent reduction in CO_2 by 2030 and net-zero carbon emissions by 2050; will retire final coal-fired EGU by 2040.[124]
- Tennessee Valley Authority: 70 percent reduction in CO_2 by 2030, 80 percent reduction by 2035, and net-zero carbon emissions by 2050.[125]
- NextEra Energy: 70 percent reduction in CO_2 by 2025, 82 percent reduction by 2030, 87 percent reduction by 2035, 94 percent reduction by 2040, and carbon-free by 2045.[126]

The geographic footprint of zero or net-zero carbon commitments made by utilities, their parent companies, or in response to a state clean energy requirement, covers portions of 47 states.[127] These statements are often made as part of long-term planning processes with considerable stakeholder involvement, including regulators.

3. State Actions to Reduce Power Sector GHG Emissions

States across the country have taken the lead in efforts to reduce GHG emissions and accelerate the power sector's trend away from fossil fuel-fired generation. These actions include

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[123] American Electric Power (AEP) is based in Ohio with operations in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. See *Clean Energy Future* at *https://www.aep.com/about/ourstory/cleanenergy*.

[124] Alliant Energy has operations in Iowa and Wisconsin. See *Our Sustainable Energy Plan* at *https://www.alliantenergy.com/cleanenergy/ourenergyvision/poweringwhatsnext/sustainableenergyplan*.

[125] Tennessee Valley Authority (TVA) is based in Tennessee with operations in Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. See *https://www.tva.com/newsroom/press-releases/tva-charts-path-to-clean-energy-future*.

[126] NextEra Energy. See *https://newsroom.nexteraenergy.com/2022-06-14-NextEra-Energy-sets-industry-leading-Real-Zero-TM-goal-to-eliminate-carbon-emissions-from-its-operations,-leverage-low-cost-renewables-to-drive-energy-affordability-for-customers*.

[127] Smart Electric Power Alliance Utility Carbon Tracker. See *https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/*. Accessed January 12, 2023.

commitments that require utilities to expand renewable and clean energy production through the adoption of renewable portfolio standards (RPS) and clean energy standards (CES), as well as other measures tailored to decarbonize state power systems enacted in specific legislation.

As of 202312023, 30 states and the District of Columbia have enforceable RPS.[128] RPS require a certain percentage of electricity that utilities sell to come from eligible renewable sources like wind and solar rather than from fossil fuel-based sources like coal and natural gas. Fifteen states have RPS targets that are at or well above 50 percent. Eight of these states—California, Illinois, Massachusetts, Maryland, Minnesota, New Jersey, Nevada, and Oregon—have targets ranging from 50 percent to just below 70 percent. Four states—Maine, New Mexico, New York, and Vermont—have RPS targets greater than or equal to 70 percent but below 100 percent, and three states—Hawaii, Rhode Island, and Virginia plus the District of Columbia—have 100 percent RPS requirements. Most of these ambitious targets fall during the next decade. Ten states and the District of Columbia have final targets that mature between 2025 and 2033, while the remaining five states impose peak requirements between 2040 and 2050. Resources that are eligible under an RPS vary by state and are determined by the state's existing energy production and possibility for renewable energy development. For example, Colorado's RPS includes a range of resources such as solar, wind, emissions-neutral coal mine methane and other sources as qualifying renewable energy sources. Hawaii's includes, but is not limited to, solar, wind, and energy produced from falling water, ocean water, waves, and water currents. RPS in some other states include landfill gas, animal wastes, CHP, and energy efficiency.[129]

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[128] Lawrence Berkeley National Laboratory, *US Renewables Portfolio Standards 2021 Status Update: Early Release,* at 9 (2021), available at *https://emp.lbl.gov/publications/us-renewables-portfolio-standards-3* (last visited November 16, 2022).
[129] NCSL (2021). *State Renewable Portfolio Standards and Goals*. Accessed at *https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx*.

States are also shifting their generating fleets away from fossil fuel generating resources through the adoption of CES. A CES requires a certain percentage of retail electricity to come from sources that are defined as clean. Unlike an RPS, which defines eligible generation in terms of the renewable attributes of its energy source, CES eligibility is based on the GHG emission attributes of the generation itself, typically with a zero or net-zero carbon emissions requirement. Twenty-one states have adopted some form of clean energy requirement or goal with 17 of those states setting 100 percent targets. In nearly all cases, the CES applies in addition to the state's other RPS requirements. Seven states, including California, Colorado, Minnesota, New York, Washington, Oregon, and Arizona, have a zero or net-zero carbon emissions requirement with most target dates falling in 2040, 2045, or 2050. Two states—New Mexico and Massachusetts—have 80 percent clean energy requirements that must be met in 2045 and 2050, respectively. Ten additional states, including Connecticut, New Jersey, Nevada, Wisconsin, Illinois, Maine, North Carolina, Nebraska, Louisiana, and Michigan, have 100 percent clean energy goals with target dates falling in either 2040 or 2050. Like an RPS, CES resource eligibility can vary from state to state. One key difference between an RPS and a CES is the extent to which a CES can allow for resources like nuclear and CCS-enabled coal and natural gas, which are not renewable but have low or zero direct GHG emission attributes that make them CES eligible.

In addition, states across the U.S. have announced specific legislation aimed at reducing GHG emissions. In California, Senate Bill 32, passed in 2016, was a landmark legislation that requires California to reduce its overall GHG emissions to 1990 levels by 2020, 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050. Senate Bill 100, passed in 2018, requires California to procure 60 percent of all electricity from renewable sources by 2030 and plan for100 percent from carbon-free sources by 2045. Senate Bills 605 and 1383, passed in 2016, require a reduction in emissions of short-lived climate pollutants like methane by 40 to 50 percent below 2013 levels by 2030.[130] Achieving the established goal of carbon neutrality by 2045 requires emissions to be balanced by carbon sequestration, carbon capture, or other technologies. Senate Bill 905, passed in 2022 requires the California Air Resources Board to establish programs for permitting CCS projects.[131]

In New York, The Climate Leadership and Community Protection Act, passed in 2019, sets several climate targets. The most important goals include an 85 percent reduction in GHG emissions by 2050, 100 percent zero-emission electricity by 2040, and 70 percent renewable energy by 2030. Other targets include 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, and 6,000 MW of solar by 2025.[132]

Washington State's Climate Commitment Act sets a target of reducing GHG emissions by 95 percent by 2050. The state is required to reduce emissions to 1990 levels by 2020, 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040, and 95 percent below 1990 levels by 2050. This also includes achieving net-zero emissions by 2050.[133]

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[130] Berkeley Law. *California Climate Policy Dashboard*. Accessed at *https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard/#:~:text=Greenhouse%20Gas%20Emission%20Reduction,-Senate%20Bill%2032&text=Landmark%20legislation%20requiring%20California%20to,program)%20to%20achieve%20this%20goal*.

[131] Berkeley Law. *California Climate Policy Dashboard*. Accessed at *https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard/#:~:text=Greenhouse%20Gas%20Emission%20Reduction,-Senate%20Bill%2032&text=Landmark%20legislation%20requiring%20California%20to,program)%20to%20achieve%20this%20goal*.

[132] New York State. *Our Progress*. Accessed at *https://climate.ny.gov/Our-Progress#:~:text=Enshrined%20into%20law%20through%20the,wide%20carbon%20neutrality%20by%202050*.

[133] Department of Ecology Washington State. *Greenhouse Gases*. Accessed at *https://ecology.wa.gov/Air-Climate/Climate-change/Tracking-greenhouse-gases*.

In addition to the prevalence of state RPS and CES programs outlined above, several states developed regulatory programs to retain nuclear power plants to preserve the significant amount of zero-emission output the plants provide, especially as many merchant nuclear plants face downward economic pressures resulting from ultra-low natural gas spot prices combined with increasing NGCC capacity. Between 2016 and 2021, New York, New Jersey, Connecticut, and Illinois took action to retain their nuclear power stations by providing state-level financial incentives. Retention of nuclear power plants is another strategy that leading states have used to ensure an increasing market share for zero-emission electricity generation. As discussed earlier, the IRA included a zero-emission nuclear power production credit in section 13105, also referred to as IRC section 45U.[134]

In the past two years, state actions have generally increased their decarbonization ambitions. For example, legislation in Illinois and North Carolina requires a transition away from GHG-emitting generation. Illinois' Climate and Equitable Jobs Act, which became law on September 25, 2021, requires all private coal-fired or oil-fired power plants to reach zero carbon emissions by 2030, municipal coal-fired plants to reach zero carbon emissions by 2045, and natural gas-fired plants to reach zero carbon emissions by 2045.[135] On October 13, 2021, North Carolina passed House Bill 951 that required the North Carolina Utilities Commission to "take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050."[136]

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[134] See *http://uscode.house.gov/view.xhtml?req=(title:26%20section:45U%20edition:prelim)*.
[135] Office of Governor J.B. Pritzer, available at *https://www.illinois.gov/news/press-release.23893.html*.
[136] General Assembly of North Carolina, House Bill 951 (2021), available at *https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v5.pdf*.

F. Projections of Power Sector Trends

Projections for the U.S. power sector—based on the landscape of market forces in addition to the known actions of Congress, utilities, and states—have indicated that the ongoing transition will continue for specific fuel types and EGUs. The EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case (*i.e.*, the EPA's projections of the power sector, which includes representation of the IRA absent further regulation), provides projections out to 2050 on future outcomes of the electric power sector.

Since the passage of the IRA in August 2022, the EPA has engaged with many external partners, including other governmental entities, academia, non-governmental organizations (NGOs), and industry, to understand the impacts that the IRA will have on power sector GHG emissions. In addition to engaging in several workgroups, the EPA has contributed to two separate journal articles that include multi-model comparisons of IRA impacts across several state-of-the-art models of the U.S. energy system and electricity sector[137] [138] and participated in public events exploring modeling assumptions for the IRA.[139] The EPA plans to continue collaborating with stakeholders, conducting external engagements, and using information gathered to refine modeling of the IRA. As such, the EPA is soliciting comment on power sector modeling of the IRA, including the assumptions and potential impacts, including assumptions about growth in electric demand, rates at which renewable generation can be built, and cost and

[137] Bistline, *et al.* (2023). "Emissions and Energy System Impacts of the Inflation Reduction Act of 2022," Under Review.
[138] Bistline, *et al.* (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022," In Preparation.
[139] Resource for the Future (2023). "Future Generation: Exploring the New Baseline for Electricity in the Presence of the Inflation Reduction Act." See *https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-of-the-inflation-reduction-act/*.

performance assumptions about all relevant technologies, including carbon capture, renewables, energy storage and other generation technologies.

While much of the discussion below focuses on the EPA's post-IRA 2022 reference case, many other analyses show similar trends, and these trends are consistent with utility IRPs and public GHG reduction commitments, as well as state actions, both of which were described in the previous sections.

1. Projections for Coal-fired Generation

In the post-IRA 2022 reference case, coal-fired steam generating unit capacity is projected to fall from 210 GW in 2021[140] to 44 GW in 2035. Generation from coal-fired steam generating units is projected to also fall from 898 thousand GWh in 2021[141] to 120 thousand GWh by 2035. This change in generation reflects the anticipated continued decline in projected coal-fired steam generating unit capacity as well as a steady decline in annual operation of those EGUs that remain online, with capacity factors falling from approximately 41 percent in 2021 to 15 percent in 2035. By 2050, coal-fired steam generating unit capacity is projected to diminish further, with only 10 GW, or less than 5 percent of 2021 capacity (and approximately 3 percent of the 2010 capacity), still in operation across the continental U.S. These projections are driven by the eroding economic opportunities for coal-fired steam generating units to operate, the continued aging of the fleet of coal-fired steam generating units, and the continued availability and expansion of low-cost alternatives, like natural gas, renewable technologies, and energy storage.

[140] U.S. Energy Information Administration (EIA), Electric Power Annual, table 4.3. November 2022. See *https://www.eia.gov/electricity/annual/*.

[141] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. See *https://www.eia.gov/electricity/annual/*.

In 2020, there was a total of 1,439 million metric tonnes of CO_2 from the power sector with coal-fired sources contributing to over half of those emissions. In the post-IRA 2022 reference case, power sector related CO_2 emission are projected to fall to 608 million metric tonnes by 2035, of which 8 percent is projected to come from coal-fired sources in 2035.

2. Projections for Natural Gas-fired Generation

As described in the post-IRA 2022 reference case, natural gas-fired capacity is expected to continue to buildout during the next decade with 61 GW of new capacity projected to come online by 2035 and 309 GW of new capacity by 2050. By 2035, the new natural gas capacity is comprised of 24 GW of simple cycle combustion turbines and 37 GW of combined cycle combustion turbines. By 2050, most of the incremental new capacity is projected to come just from simple cycle combustion turbines. This also represents a higher rate of new simple cycle combustion turbine builds compared to the reference periods (*i.e.*, 2000–2006 and 2007–2021) discussed previously in this section. Some of the reasons for this continued growth in natural gas-fired capacity include anticipated sustained lower fuel costs and the flexibility offered by combustion turbines. Simple cycle combustion turbines operate at lower efficiencies but offer fast startup times to meet peaking load demands. In addition, combustion turbines, along with energy storage technologies, support the expansion of renewable electricity by meeting demand during peak periods and providing flexibility around the variability of renewable generation and electricity demand.

It should be noted that despite this increase in capacity, both overall generation and emissions from the natural gas-fired capacity are projected to decline. Generation from natural gas units is projected to fall from 1,579 thousand GWh in 2021[142] to 1,402 thousand GWh by 2035. Power sector related CO_2 emissions from natural gas-fired EGUs are projected to reach 527 million metric tons in 2035, 93 percent of which comes from NGCC sources.

The decline in generation and emissions is driven by a projected decline in NGCC capacity factors. In model projections, NGCC units have a capacity factor early in the projection period of 64 percent, but by 2035, capacity factor projections fall to 50 percent as many of these units switch from base load operation to more intermediate load operation to support the integration of variable renewable energy resources. Natural gas simple cycle combustion turbine capacity factors also fall, although since they are used primarily as a peaking resource and their capacity factors are already below 10 percent annually, their impact on generation and emissions changes are less notable.

Some of the reasons for this continued growth in natural gas-fired capacity include anticipated sustained lower fuel costs and the greater efficiency and flexibility offered by combustion turbines. Simple cycle combustion turbines operate at lower efficiencies but offer fast startup times to meet peaking load demands. In addition, combustion turbines, along with energy storage technologies, support the expansion of renewable electricity by meeting demand during peak periods and providing flexibility around the variability of renewable generation and electricity demand. In the longer term, as renewables and battery storage grow, they are anticipated to outcompete the need for natural gas-fired generation and the overall utilization of natural gas-fired capacity is expected to decline.

[142] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. See *https://www.eia.gov/electricity/annual/*.

3. Projections for Renewable Generation

The EIA's *Short-Term Energy Outlook* (STEO) suggests that the U.S. will continue its expansion of wind and solar renewable capacity with most of the growth in electricity capacity additions in the next 2 years to come from renewable energy sources.[143] The EIA projects utility-scale solar capacity to grow by approximately 29 GW in 2023 and by 35 GW in 2024 wind generating capacity to grow by 7 GW in 2023. and by 7.5 GW in 2024. These increases in new renewable capacity will continue to reduce the demand for fossil fuel-fired generation.

In the post-IRA 2022 reference case projections, that this short-term trend in renewable capacity is expected to continue. Non-hydroelectric utility-scale renewable capacity is projected to increase from 209 GW in 2021 to 668 GW by 2035 and then to 1,293 GW by 2050. This capacity growth is comprised mostly of wind and solar. The post-IRA 2022 reference case shows projections of 399 GW of wind capacity by 2035 and 748 GW by 2050. Utility-scale solar capacity has a similar trajectory with 263 GW by 2035 and 539 GW by 2050 and small-scale or distributed solar capacity (*e.g.*, rooftop solar) similarly increases from 33 GW in 2021 to 198 GW in 2050.[144] In total, non-hydroelectric utility-scale renewable generation is projected to produce 45 percent of electricity generation by 2035 in the post-IRA 2022 reference case.

4. Projections for Energy Storage

According to EIA, the capacity of battery energy storage is expected to increase by 10 times between 2019 and 2023, and more than 6 GW of additional battery storage capacity is

[143] U.S. Energy Information Administration (EIA). *Short-Term Energy Outlook*,March 2023. See *https://www.eia.gov/outlooks/steo/*.
[144] U.S. Energy Information Administration (EIA), Electric Power Annual, table 4.3. November 2022. See *https://www.eia.gov/electricity/annual/*.

planned to be co-located with solar generation.[145] The benefit of pairing energy storage systems with solar capacity deployment is that the batteries can recharge throughout the middle of the day when surplus energy is available. Then this stored energy can be discharged during peak hours, displacing fossil fuel-fired generation. This also reduces curtailment of renewable energy when generation exceeds demand.

The build out of energy storage is projected to continue in the long-term, enabling the integration of renewable technologies with lower emission consequences. The post-IRA 2022 reference case shows projections of 97 GW of energy storage to be available on the grid by 2035 and 152 GW by 2050.

5. Projections for Nuclear Energy

The post-IRA 2022 reference case shows a steady decline in nuclear generating capacity, dropping from 96 GW in 2021 to 84 GW or by 12 percent by 2035. In the short-term, capacity reductions are expected to be delayed in part due to programs passed as part of the IIJA and IRA. These acts, along with several state programs, support the continued use of existing nuclear facilities by providing payments that will likely keep reactors in affected regions profitable for the next 5–10 years. After 2035, the EPA projects nuclear capacity retirements to occur as EGUs begin to age out of operation, and by 2050, the nuclear fleet is projected to reduce by more than half, to 45 GW. However, breakthrough technologies like small modular reactors, if successful, could result in higher levels of nuclear capacity than discussed here. For example, output from

[145] U.S. Energy Information Administration (EIA). Preliminary Monthly Electric Generator Inventory, December 2020 Form EIA-860M. See *https://www.eia.gov/analysis/studies/electricity/batterstorage/*.

advanced nuclear generation could range from negligible to as high as 3,600 terawatt-hours per year (TWh/yr) by 2050.[146]

V. Statutory Background and Regulatory History for CAA Section 111

A. Statutory Authority to Regulate GHGs from EGUs under CAA Section 111

The EPA's authority for and obligation to issue these proposed rules is CAA section 111, which establishes mechanisms for controlling emissions of air pollutants from new and existing stationary sources. CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards.

1. Regulation of Emissions From New Sources

Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources (including modified and reconstructed sources) in the source category. Under CAA section 111(a)(2), a "new source" is defined as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source." Under CAA section 111(a)(3), a "stationary source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant." Under CAA section 111(a)(4),

[146] "Advancing Nuclear Energy Evaluating Deployment, Investment, and Impact in America's Clean Energy Future" Breakthrough Institute, July 6, 2022.

"modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. While this provision treats modified sources as new sources, EPA regulations also treat a source that undergoes "reconstruction" as a new source. Under the provisions in 40 CFR 60.15, "reconstruction" means the replacement of components of an existing facility such that: (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

The standards of performance for new sources are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." The term "standard of performance" in CAA 111(a)(1) makes clear that the EPA is to determine both the "best system of emission reduction … adequately demonstrated" (BSER) for the regulated sources in the source category and the "degree of emission limitation achievable through the application of the [BSER]." *West Virginia v. EPA*, 142 S. Ct. 2587, 2601 (2022). To determine the BSER, the EPA first identifies the "system[s] of emission reduction" that are "adequately demonstrated," and then determines the "best" of those systems, "taking into account" factors including "cost," "nonair quality health and environmental impact," and "energy requirements." The EPA then derives from that system an "achievable" "degree of emission limitation." The EPA must then, under CAA section 111(b)(1)(B), promulgate "standard[s] for emissions"—the NSPS—that reflect that level of stringency. CAA section 111(b)(5) precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources may select any measure or combination of measures that will achieve the standard.

2. Regulation of Emissions From Existing Sources

When the EPA establishes a standard for emissions of an air pollutant from new sources within a category, it must also, under CAA section 111(d), regulate emissions of that pollutant from *existing* sources within the same category, unless the pollutant is regulated under the National Ambient Air Quality Standards (NAAQS) program, under CAA sections 108–110, or the National Emission Standards for Hazardous Air Pollutants (NESHAP) program, under CAA section 112. See CAA section 111(d)(1)(A)(i) and (ii); *American Lung Ass'n v. EPA*, 985 F.3d 914, 988 (D.C. Cir. 2021).

CAA section 111(d) establishes a framework of "cooperative federalism for the regulation of existing sources." *American Lung Ass'n*, 985 F.3d at 931. CAA sections 111(d)(1)(A)-(B) require "[t]he Administrator … to prescribe regulations" that require "[e]ach state … to submit to [EPA] a plan … which establishes standards of performance for any existing stationary source for" the air pollutant at issue, and which "provides for the implementation and enforcement of such standards of performance." CAA section 111(a)(6) defines an "existing source" as "any stationary source other than a new source."

To meet these requirements, the EPA promulgates "emission guidelines" that identify the BSER and the degree of emission limitation achievable through the application of the BSER. Each state must then establish standards of performance for its sources that reflect that level of stringency. However, the states need not compel regulated sources to adopt the particular components of the BSER itself. The EPA's emission guidelines must also permit a state, "in applying a standard of performance to any particular source," to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." 42 U.S.C. 7411(d)(1). Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the source, in the same manner as the provisions of an approved state implementation plan (SIP) under the Act. If a state elects not to submit a plan or submits a plan that the EPA does not find "satisfactory," the EPA must promulgate a plan that establishes Federal standards of performance for the state's existing sources. CAA section 111(d)(2)(A).

3. EPA Review of Requirements

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years, review and, if appropriate, revise" new source performance standards. However, the Administrator need not review any such standard if the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an NSPS, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category. CAA section 111 does not by its terms require the EPA to review emission guidelines for existing sources, but the EPA retains the authority to do so.

B. History of EPA Regulation of Greenhouse Gases From Electricity Generating Units Under CAA Section 111 and Caselaw

The EPA has listed more than 60 stationary source categories under CAA section 111(b)(1)(A). See 40 CFR part 60, subparts Cb–OOOO. In 1971, the EPA listed fossil fuel-fired EGUs (which includes natural gas, petroleum, and coal) that use steam-generating boilers in a category under CAA section 111(b)(1)(A). See 36 FR 5931 (March 31, 1971) (listing "fossil fuel-fired steam generators of more than 250 million Btu per hour heat input"). In 1977, the EPA listed fossil fuel-fired combustion turbines, which can be used in EGUs, in a category under CAA section 111(b)(1)(A). See 42 FR 53657 (October 3, 1977) (listing "stationary gas turbines").

In 2015, the EPA promulgated two rules that addressed CO_2 emissions from fossil fuel-fired EGUs. The first promulgated standards of performance for new fossil fuel-fired EGUs. "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule," (80 FR 64510; October 23, 2015) (2015 NSPS). The second promulgated emission guidelines for existing sources. "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule," (80 FR 64662; October 23, 2015) (Clean Power Plan, or CPP).

1. 2015 NSPS

In 2015, the EPA promulgated an NSPS to limit emissions of GHGs, manifested as CO_2, from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units, *i.e.,* utility boilers and IGCC EGUs, and newly constructed and reconstructed stationary combustion turbine EGUs. These final standards are codified in 40 CFR part 60, subpart TTTT.

In promulgating the NSPS for newly constructed fossil fuel-fired steam generating units, the EPA determined the BSER to be a new, highly efficient, supercritical pulverized coal (SCPC) EGU that implements post-combustion partial CCS technology. The EPA concluded that CCS was adequately demonstrated (including being technically feasible) and widely available and could be implemented at reasonable cost. The EPA identified natural gas co-firing and IGCC technology (either with natural gas co-firing or implementing partial CCS) as alternative methods of compliance.

The 2015 NSPS included standards of performance for steam generating units that undergo a "reconstruction" as well as units that implement "large modifications," *(i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The 2015 NSPS did not establish standards of performance for steam generating units that undertake "small modifications" *(i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent), due to the limited information available to inform the analysis of a BSER and corresponding standard of performance.

The 2015 NSPS also finalized standards of performance for newly constructed and reconstructed stationary combustion turbine EGUs. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA finalized a standard based on efficient NGCC technology as the BSER. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines and for both base load and non-base load multi-fuel-fired stationary combustion turbines, the EPA finalized a heat input-based clean fuels standard. The EPA did not promulgate final standards of performance for modified stationary combustion turbines due to lack of information. These standards remain in effect today.

The EPA received six petitions for reconsideration of the 2015 NSPS. On May 6, 2016 (81 FR 27442), the EPA denied five of the petitions on the basis they did not satisfy the statutory conditions for reconsideration under CAA section 307(d)(7)(B), and deferred action on one petition that raised the issue of the treatment of biomass.

Multiple parties also filed petitions for judicial review of the 2015 NSPS in the D.C. Circuit. After briefing, the court granted the EPA's motion to hold the cases in abeyance while the Agency reviews the rule and considers whether to propose revisions to it.

In the 2015 NSPS, the EPA noted that it was authorized to regulate GHGs from the fossil fuel-fired EGU source categories because it had listed those source categories under CAA section 111(b)(1)(A). The EPA added that CAA section 111 did not require it to make a determination that GHGs from EGUs contribute significantly to dangerous air pollution (a pollutant-specific significant contribution finding), but in the alternative, the EPA did make that finding. It explained that "[greenhouse gas] air pollution may reasonably be anticipated to endanger public health or welfare," 80 FR 64,530 and emphasized that power plants are "by far the largest emitters" of greenhouse gases among stationary sources in the U.S. *Id.* at 64,522. In *American Lung Ass'n v. EPA*, 985 F.3d 977 (D.C. Cir. 2021), the court held that even if the EPA were required to determine that CO_2 from fossil fuel-fired EGUs contributes significantly to dangerous air pollution—and the court emphasized that it was not deciding that the EPA was required to make such a pollutant-specific determination—the determination in the alternative that the EPA made in the 2015 NSPS was not arbitrary and capricious and, accordingly, the EPA had a sufficient basis to regulate greenhouse gases from EGUs under CAA section 111(d) in the ACE Rule. The EPA is not reopening or soliciting comment on any of those determinations in the 2015 NSPS concerning its rational basis to regulate GHG emissions from EGUs or its alternative finding that GHG emissions from EGUs contribute significantly to dangerous air pollution.

2. 2018 Proposal to Revise the 2015 NSPS

In 2018, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units. "Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule," (83 FR 65424; December 20, 2018). The EPA proposed to revise the NSPS for newly constructed units, based on a revised BSER of a highly efficient SCPC, without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. The EPA never took further action to finalize that proposed rule, is not soliciting further comment on it in this proposal, and intends to withdraw it through a separate notice.

3. Clean Power Plan

With the promulgation of the 2015 NSPS, the EPA also incurred a statutory obligation under CAA section 111(d) to issue emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs and stationary combustion turbine EGUs, which the EPA initially fulfilled with the promulgation of the CPP. See 80 FR 64662 (October 23, 2015). The EPA first determined that the BSER included three types of measures: (1) improving heat rate (*i.e.*, the amount of fuel that must be burned to generate a unit of electricity) at coal-fired steam plants; (2) substituting increased generation from lower-emitting NGCC plants for generation from higher-emitting steam plants (which are primarily coal-fired); and (3) substituting increased generation from new renewable energy sources for generation from fossil fuel-fired steam plants and combustion turbines. See 80 FR 64667 (October 23, 2015). The latter two measures are known as "generation shifting" because they involve shifting electricity generation from higher-emitting sources to lower-emitting ones. See 80 FR 64728–29 (October 23, 2015).

The EPA based this BSER determination on a technical record that evaluated generation-shifting, including its cost-effectiveness, against the relevant statutory criteria for BSER and on a legal interpretation that the term "system" in CAA section 111(a)(1) is sufficiently broad to encompass shifting of generation from higher-emitting to lower-emitting sources. See 80 FR 64720 (October 23, 2015). The EPA then determined the "degree of emission limitation achievable through the application of the [BSER]," CAA section 111(a)(1), expressed as emission performance rates. See 80 FR 64667 (October 23, 2015). The EPA explained that a state would "have to ensure, through its plan, that the emission standards it establishes for its sources individually, in the aggregate, or in combination with other measures undertaken by the [S]tate, represent the equivalent of" those performance rates (80 FR 64667; October 23, 2015). Neither states nor sources were required to apply the specific measures identified in the BSER (80 FR 64667; October 23, 2015), and states could include trading or averaging programs in their state plans for compliance. See 80 FR 64840 (October 23, 2015).

Numerous states and private parties petitioned for review of the CPP before the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court stayed the rule pending review, *West Virginia v. EPA*, 577 U.S. 1126 (2016), and the D.C. Circuit held the litigation in abeyance, and ultimately dismissed it, as the EPA reassessed its position. *American Lung Ass'n*, 985 F.3d at 937.

4. The CPP Repeal and Affordable Clean Energy Rule

In 2019, the EPA repealed the CPP and replaced it with the ACE Rule. In contrast to its interpretation of CAA section 111 in the CPP, in the ACE Rule the EPA determined that the statutory "text and reasonable inferences from it" make "clear" that a "system" of emission reduction under CAA section 111(a)(1) "is limited to measures that can be applied to and at the level of the individual source," (84 FR 32529; July 8, 2019); that is, the system must be limited to control measures that could be applied "inside the fenceline" of each source to reduce emissions at each source. See 84 FR 32523–24 (July 8, 2019). Specifically, the ACE Rule argued that the requirements in CAA sections 111(d)(1), (a)(3), and (a)(6), that each state establish a standard of performance "for" "any existing source," defined, in general, as any "building … [or] facility," and the requirement in CAA section 111(a)(1) that the degree of emission limitation must be "achievable" through the "application" of the BSER, by their terms, impose this limitation. The EPA concluded that generation shifting is not such a control measure. See 84 FR 32546 (July 8, 2019). The EPA further determined that, absent "a clear statement from Congress," the term "'system of emission reduction'" should not be read to encompass "generation-shifting measures." See 84 FR 32529 (July 8, 2019). The EPA acknowledged, that "[m]arket-based forces ha[d] already led to significant generation shifting in the power sector," (84 FR 32532; July 8, 2019), and that there was "likely to be no difference between a world where the CPP is implemented and one where it is not." See 84 FR 32561 (July 8, 2019); the Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, 2-1 to 2-5.[147]

Second, the EPA promulgated in the ACE Rule a new set of emission guidelines for existing coal-fired steam-generating EGUs. See 84 FR 32532 (July 8, 2019). In light of "the legal

[147] See *https://www.epa.gov/sites/default/files/2019-06/documents/utilities_ria_final_cpp_repeal_and_ace_2019-06.pdf*.

interpretation adopted in the repeal of the CPP," (84 FR 32532; July 8, 2019)—which "limit[ed] 'standards of performance' to systems that can be applied at and to a stationary source," (84 FR 32534; July 8, 2019)—the EPA found the BSER to be heat rate improvements alone. See 84 FR 32535 (July 8, 2019). The EPA listed various technologies that could improve heat rate (84 FR 32536; July 8, 2019), and identified the "degree of emission limitation achievable" by "providing ranges of expected [emission] reductions associated with each of the technologies." See 84 FR 32537–38 (July 8, 2019).

The EPA also stated that, under the ACE Rule, compliance measures that the state plans could authorize the sources to implement "should correspond with the approach used to set the standard in the first place," (84 FR 32556; July 8, 2019), and therefore must "apply at and to an individual source and reduce emissions from that source." See 84 FR 32555–56 (July 8, 2019). The EPA concluded that various measures besides generation shifting—including averaging (*i.e.*, allowing multiple sources to average their emissions to meet an emission-reduction goal), and trading (*i.e.*, allowing sources to exchange emission credits or allowances)—did not meet that requirement. The EPA therefore barred states from using such measures in their plans. See 84 FR 32556 (July 8, 2019).

5. D.C. Circuit Decision in *American Lung Ass'n v. EPA* Concerning the CPP Repeal and ACE Rule

Numerous states and private parties petitioned for review of the CPP Repeal and ACE Rule. In 2021, the D.C. Circuit vacated the ACE Rule, including the CPP Repeal. *American Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021). The court held, among other things, that CAA section 111(d) does not limit the EPA, in determining the BSER, to inside-the-fenceline measures. The court noted that "the sole ground on which the EPA defends its abandonment of the [CPP] in favor of the ACE Rule is that the text of [CAA section 111] is clear and unambiguous in constraining the EPA to use only improvements at and to existing sources in its [BSER].” 985 F.3d at 944. The court found “nothing in the text, structure, history, or purpose of [CAA section 111] that compels the reading the EPA adopted.” 985 F.3d at 957. The court explained that contrary to the ACE Rule, the above-noted requirements in CAA section 111 that each state must establish a standard of performance “for” any existing “building … [or] facility,” mean that the state must establish standards applicable to each regulated stationary source; and the requirements that the degree of emission limitation must be achievable through the “application” of the BSER could be read to mean that the sources must be able to apply the system to reduce emissions across the source category. None of these requirements, the court further explained, can be read to mandate that the BSER is limited to some measure that each source can apply to its own facility to reduce its own emissions in a specified amount. 985 F.3d at 944–51. The court likewise rejected the view that the CPP’s use of generation-shifting implicated a “major question” requiring unambiguous authorization by Congress. 985 F.3d at 958–68.

Having rejected the CPP Repeal Rule’s view, also reflected in the ACE Rule, that CAA section 111 unambiguously requires that the BSER be “one that can be applied to and at the individual source,” the court also “reject[ed] the ACE Rule’s exclusion from [CAA section 111(d)] of compliance measures” that do not meet that requirement. 985 F.3d at 957. Thus, the court held that CAA section 111 does not preclude states from allowing trading or averaging. The court explained that the ACE Rule’s premise for its view that compliance measures are limited to inside-the-fenceline is that BSER measures are so limited, but the court further stated that this premise was invalid. The court added that in any event, CAA section 111(d) says nothing about the type of compliance measures states may adopt, regardless of what the EPA identifies as the BSER. *Id*. at 957–58.

The D.C. Circuit concluded that, because the EPA had relied on an "erroneous legal premise," both the CPP Repeal Rule and the ACE Rule should be vacated. 985 F.3d at 995. The court did not decide, however, "whether the approach of the ACE Rule is a permissible reading of the statute as a matter of agency discretion," 985 F.3d at 944, and instead "remanded to the EPA so that the Agency may 'consider the question afresh,'" 985 F.3d at 995 (citations omitted). The court also rejected the arguments that the EPA cannot regulate CO_2 emissions from coal-fired power plants under CAA section 111(d) at all because it had already regulated mercury emissions from coal-fired power plants under CAA section 112. 985 F.3d at 988.

Because the D.C. Circuit vacated the ACE Rule on the grounds noted above, it did not address the numerous other challenges to the ACE Rule, including the arguments by Petitioners that the heat rate improvement BSER was inadequate because of the limited amount of reductions it achieved and because the ACE Rule failed to include an appropriately specific degree of emission limitation.

Upon a motion from the EPA, the D.C. Circuit agreed to stay its mandate with respect to vacatur of the CPP Repeal, *American Lung Assn v. EPA*, No. 19-1140, Order (February 22, 2021), so that the CPP remained repealed. In its motion, the EPA explained that the CPP should remain repealed because the deadline for states to submit their plans under the CPP had long since passed. In addition, and most importantly, because of ongoing changes in electricity generation—in particular, retirements of coal-fired electricity generation—the emissions reductions that the CPP was projected to achieve had already been achieved by 2021. *American Lung Assn v. EPA*, No. 19-1140, Respondents' Motion for a Partial Stay of Issuance of the

Mandate (February 12, 2021). Therefore, following the D.C. Circuit's decision, no EPA rule under CAA section 111 to reduce GHGs from existing fossil fuel-fired EGUs remained in place, and the EPA proceeded with this new rulemaking.

6. U.S. Supreme Court Decision in *West Virginia v. EPA* Concerning the CPP

In 2022, the U.S. Supreme Court reversed the D.C. Circuit's vacatur of the ACE Rule's embedded repeal of the CPP. *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). The Supreme Court made clear that CAA section 111 authorizes the EPA to determine the BSER and the degree of emission limitation that state plans must achieve. *Id.* at 2601–02. However, the Supreme Court invalidated the CPP's generation-shifting BSER under the major questions doctrine. The Court characterized the generation-shifting BSER as "restructuring the Nation's overall mix of electricity generation," and held that the EPA's claim that CAA section 111 authorized it to promulgate generation shifting as the BSER was "not only unprecedented; it also effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind." *Id*. at 2612 (internal quotation marks, brackets, and citation omitted). The Court explained that the EPA, in prior rules under CAA section 111, had set emissions limits based on "measures that would reduce pollution by causing the regulated source to operate more cleanly." *Id*. at 2610. The Court noted with approval those "more traditional air pollution control measures," and gave as examples "fuel-switching" and "add-on controls," which, the Court observed, the EPA had considered in the CPP. *Id*. at 2611 (internal quotations marks and citation omitted). In contrast, the Court continued, generation-shifting was "unprecedented" because "[r]ather than focus on improving the performance of individual sources, it would improve the overall power system by lowering the carbon intensity of power generation. And it would do that by forcing a shift throughout the power grid from one type of energy source to another." *Id*. at

2611-12 (internal quotation marks, emphasis, and citation omitted). The Court also emphasized that the adoption of generation shifting was based on a "very different kind of policy judgment [than prior CAA section 111 rules]: that it would be 'best' if coal made up a much smaller share of national electricity generation." *Id*. at 2612. The Court recognized that a rule based on traditional measures "may end up causing an incidental loss of coal's market share," but emphasized that the CPP was "obvious[ly] differen[t]" because, with its generation-shifting BSER, it "simply announc[ed] what the market share of coal, natural gas, wind, and solar must be, and then require[ed] plants to reduce operations or subsidize their competitors to get there." *Id.* at 2613 n. 4. Beyond highlighting the novelty of generation shifting, the Court also emphasized "the magnitude and consequence" of the CPP. *Id.* at 2616. It noted "the magnitude of this unprecedented power over American industry," *id.* at 2612 (internal quotation marks and citation omitted), and added that the EPA's adoption of generation shifting "represent[ed] a transformative expansion in its regulatory authority." *Id*. at 2610 (internal quotation marks and citation omitted). The Court also viewed the CPP as promulgating "a program that … Congress had considered and rejected multiple times." *Id*. at 2614 (internal quotation marks and citation omitted). The Court explained that "[a]t bottom, the [CPP] essentially adopted a cap-and-trade scheme, or set of state cap-and-trade schemes, for carbon," and that Congress "has consistently rejected proposals to amend the Clean Air Act to create such a program." *Id.*

For these and related reasons, the Court viewed the CPP as raising a major question, and therefore, under the major questions doctrine, required "clear congressional authorization" as a basis. *Id*. (internal quotation marks and citation omitted). The EPA had defended generation shifting as qualifying as a "system of emission reduction" under CAA section 111(a)(1), but the

Court found that the term "system" is "a vague statutory grant [that] is not close to the sort of clear authorization required" under the doctrine, *id*., and, on that basis, invalidated the CPP.

The Court declined to address the D.C. Circuit's conclusion that the text of CAA section 111 did not limit the type of "system" the EPA could consider as the BSER to inside-the-fenceline measures. *See id.* at 2615 ("We have no occasion to decide whether the statutory phrase 'system of emission reduction' refers *exclusively* to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER." (emphasis in original)). Nor did the Court address the scope of the states' compliance flexibilities.

7. D.C. Circuit Order to Reinstate the ACE Rule

On October 27, 2022, the D.C. Circuit responded to the U.S. Supreme Court's reversal by recalling its mandate for the vacatur of the ACE Rule. *American Lung Ass'n v. EPA*, No. 19-1140, Order (October 27, 2022). Accordingly, at that time, the ACE Rule came back into effect. The court also revised its judgment to deny petitions for review challenging the CPP Repeal Rule, consistent with the *West Virginia* decision, so that the CPP remains repealed. The court took further action denying several of the petitions for review unaffected by the Supreme Court's decision in *West Virginia*, which means that certain parts of its 2021 decision in *American Lung Ass'n* remain valid. These parts include the holding that the EPA's prior regulation of mercury emissions from coal-fired electric power plants under CAA section 112 does not preclude the Agency from regulating CO_2 from coal-fired electric power plants under CAA section 111, and the holding, discussed above, that the 2015 NSPS included a valid significant contribution determination and therefore provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. The court's holding to invalidate amendments to the implementing regulations applicable to emission guidelines under CAA section 111(d) that extended the preexisting schedules for state and federal actions and sources' compliance, also remains valid. Based on the EPA's stated intention to replace the ACE Rule, the court stayed further proceedings with respect to the ACE Rule, including the various challenges that its BSER was flawed because it did not achieve sufficient emission reductions and failed to specify an appropriately specific degree of emission limitation.

C. Detailed Discussion of CAA Section 111 Requirements

This section discusses in more detail the key requirements of CAA section 111 for both new and existing sources that are relevant for these rulemakings.

1. Approach to the Source Category and Subcategorizing

CAA section 111 requires the EPA first to list stationary source categories that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare and then to regulate new sources within each such source category. CAA section 111(b)(2) grants the EPA discretion whether to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards," which we refer to as "subcategorizing." The D.C. Circuit has stated that whether and how to subcategorize is a decision for which the EPA is entitled to a "high degree of deference" because it entails "scientific judgement." *Lignite Energy Council v. EPA*, 198 F3d 930, 933 (D.C. Cir. 1999); *see Sierra Cub, v. Costle*, 657 F.2d 298, 318-19 (D.C. Cir. 1981).

CAA section 111(d)(1) is silent as to whether the EPA may subcategorize. The EPA interprets this provision to authorize the Agency to exercise discretion as to whether and, if so, how to subcategorize, for the following reasons. CAA section 111(d)(1) provides a broad grant of authority to the EPA, directing it to "prescribe regulations which shall establish a procedure…under which each State shall submit to the Administrator a plan [with standards of performance for existing sources.]" The EPA promulgates emission guidelines under this provision directing the states to regulate existing sources. The Supreme Court has recognized the breadth of authority that CAA section 111(d) grants the EPA:

> Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d). The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, "the best system of emission reduction ... that has been adequately demonstrated for [existing covered] facilities."

West Virginia v. EPA, 142 S. Ct. at 2601–02 (citations omitted).. That this broad authority under CAA section 111(d) includes subcategorization follows from the fact that these provisions authorize the EPA to determine the BSER. Subcategorizing is a mechanism for determining different controls to be the BSER for different sets of sources. This is clear from CAA section 111(b)(2) itself, which authorizes the EPA to subcategorize new sources "for the purpose of establishing … standards." In addition, the EPA's longstanding implementing regulations under CAA section 111(d) provide that the Administrator will specify different emission guidelines or compliance times or both "for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or [based on] similar factors."[148]

The EPA's authority to "distinguish among classes, types, and sizes within categories," as provided under CAA section 111(b)(2), generally allows the Agency to place types of sources into subcategories when they have characteristics that are relevant to the controls they can apply to reduce their emissions. This is consistent with the commonly understood meaning of the term "type" in CAA section 111(b)(2): "a particular kind, class, or group," or "qualities common to a

[148] 40 CFR 60.22(b)(5), 60.22a(b)(5).

number of individuals that distinguish them as an identifiable class." See *https://www.merriam-webster.com/dictionary/type*. That is, subcategorization is appropriate for a set of sources that have qualities in common that are relevant for determining what controls are appropriate for those sources. And where the qualities in common are *not* relevant for determining what controls are appropriate, subcategorization is not allowed. This view is consistent with the D.C. Circuit's interpretation of CAA section 112(d)(1), which is a subcategorization provision that is identical to CAA section 111(b)(2). In *NRDC v. EPA*, 489 F.3d 1364, 1375–76 (D.C. Cir. 2007), the court upheld the EPA's decision under CAA section 112(d)(1) *not* to subcategorize sources subject to control requirements under CAA section 112(d)(3), known as the maximum achievable control technology (MACT) floor, on the basis of costs. That was because the EPA is not authorized to consider costs in setting the MACT floor. *See Chem. Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 131 (1985) (Court interprets similar provision under the Clean Water Act to grant the EPA broad discretion).

The EPA has developed subcategories in numerous rulemakings under CAA section 111 since it began promulgating them in the 1970s. These rulemakings have included subcategories on the basis of the size of the sources, see 40 CFR 60.40b(b)(1)-(2) (subcategorizing certain coal-fired steam generating units on the basis of heat input capacity); the types of fuel combusted, *see Sierra Cub, v. EPA*, 657 F.2d 298, 318-19 (D.C. Cir. 1981) (upholding a rulemaking that established different NSPS "for utility plants that burn coal of varying sulfur content"), 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (subdividing new combustion turbines on the basis of type of fuel combusted); the types of equipment used to produce products, see 81 FR 35824 (June 3, 2016) (promulgating separate NSPS for many types of oil and gas sources, such as centrifugal compressors, pneumatic controllers, and well sites);

types of manufacturing processes used to produce product, see 42 FR 12022 (March 1, 1977) (announcing availability of final guideline document for control of atmospheric fluoride emissions from existing phosphate fertilizer plants) and "Final Guideline Document: Control of Fluoride Emissions From Existing Phosphate Fertilizer Plants, EPA-450/2-77-005 1-7 to 1-9, including table 1-2 (applying different control requirements for different manufacturing operations for phosphate fertilizer); levels of utilization of the sources, see 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (dividing new natural gas-fired combustion turbines into the subcategories of base load and non-base load); and geographic location of the sources, see 71 FR 38482 (July 6, 2006) (SO_2 NSPS for stationary combustion turbines subcategories turbines on the basis of whether they are located in, for example, a continental area, a noncontinental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska), *see also Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981) (stating that the EPA could create different subcategories for sources in the eastern and western U.S. for requirements that depend on water-intensive controls). As these references indicate, the EPA has subcategorized many times in rulemaking under CAA sections 111(b) and 111(d) and based on a wide variety of physical, locational, and operational characteristics.

Regardless of whether the EPA subcategorizes within a source category for purposes of determining the BSER and the emission performance level for the emission guideline, a state retains certain flexibility in assigning standards of performance to its affected EGUs. The statutory framework for CAA section 111(d) emission guidelines, and the flexibilities available to states within that framework, are discussed below.

2. Key Elements of Determining a Standard of Performance

Congress first included the definition of "standard of performance" when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. The current text reads: "The term 'standard of performance' means a standard for emission of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[150] The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since 1973,[151] and has developed a body of case law that interprets the term "standard of performance," as discussed throughout this preamble.

The basis for standards of performance, whether promulgated by the EPA under CAA section 111(b) or established by the states under CAA section 111(d), is that the EPA determines the "degree of emission limitation" that is "achievable" by the sources by application of a "system of emission reduction" that the EPA determines is "adequately demonstrated," "taking into account" the factors of "cost … nonair quality health and environmental impact and energy requirements," and that the EPA determines to be the "best." The D.C. Circuit has stated that in determining the "best" system, the EPA must also take into account "the amount of air pollution"[152] reduced and the role of "technological innovation."[153] The court has emphasized

[150] 42 U.S.C. § 7411(a)(1).
[151] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981); *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999); *Portland Cement Ass'n v. EPA*, 665 F.3d 177 (D.C. Cir. 2011); *American Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021), *rev'd in part*, *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). *See also Delaware v. EPA*, No. 13-1093 (D.C. Cir. May 1, 2015).
[152] *See Sierra Club v. Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).
[153] *See Sierra Club v. Costle,* 657 F.2d at 347.

that the EPA has discretion in weighing those various factors.[154] [155]

Our overall approach to determining the BSER and degree of emission limitation achievable, which incorporates the various elements, is as follows: First, we identify "system[s] of emission reduction" that have been "adequately demonstrated" for a particular source category. Second, we determine the "best" of these systems after evaluating the amount of reductions, costs, any nonair health and environmental impacts, and energy requirements. And third, we determine an achievable emission limit based on application of the BSER.[156] For a CAA section 111(b) rule, we determine the emissions standard—that is, the standard of performance—that reflects the achievable emission limit. For a CAA section 111(d) rule, the states have the obligation of establishing standards of performance for the affected sources that reflect the degree of emission limitation that the EPA has determined.

The remainder of this subsection discusses the various elements in our general analytical approach.

[154] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

[155] Although CAA section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the "adequately demonstrated" determination, the D.C. Circuit's case law may be read to treat them as part of the "best" determination. *See Sierra Club v. Costle,* 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority "when determining the best technological system to weigh cost, energy, and environmental impacts"). Nevertheless, it does not appear that those two approaches would lead to different outcomes. *See, e.g.*, *Lignite Energy Council v. EPA*, 198 F.3d at 933 (rejecting challenge to the EPA's cost assessment of the "best demonstrated system"). Regardless of whether the factors are part of the "adequately demonstrated" determination or the "best" determination, our analysis and outcome would be the same.

[156] See*, e.g.*, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49490, 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

a. System of Emission Reduction

The CAA does not define the phrase "system of emission reduction." In *American Lung Ass'n v. EPA,* the D.C. Circuit stated that "[t]he ordinary meaning of the[] term[]" reflect[s] an intentional effort to confer the flexibility necessary for effective regulation appropriate to the context," 985 F.3d at 947 (internal quotation marks omitted), although the court further noted that other requirements "significantly rein[] in" the controls the EPA may select, and the court cited the requirements, discussed below, to consider "cost," "nonair quality health and environmental impact," and "energy requirements," and to ensure that the system is "adequately demonstrated." Id. at 962. In *West Virginia v. EPA,* the Supreme Court applied the major questions doctrine and held that the term "system" does not provide the requisite clear authorization to support the CPP's BSER, which the Court described as "carbon emissions caps based on a generation shifting approach." 142 S. Ct. at 2614.

b. "Adequately Demonstrated"

Under CAA section 111(a)(1), in order for a "system of emission reduction" to serve as the basis for an "achievable" emission limitation, the Administrator must determine that the system is "adequately demonstrated." This means, according to the D.C. Circuit, that the system is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[157] It does not mean that the system "must be in actual routine use somewhere."[158] Rather, the court has said, "[t]he Administrator may make a

[157] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974).
[158] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."[159] Similarly, the EPA may "hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible."[160] Ultimately, the analysis "is partially dependent on 'lead time,'" that is, "the time in which the technology will have to be available."[161] It should be emphasized that the EPA may treat a set of control measures as "adequately demonstrated" regardless of whether the measures are in widespread commercial use. For example, the D.C. Circuit upheld the EPA's determination that selective catalytic reduction (SCR) was adequately demonstrated to reduce NOx emissions from coal-fired industrial boilers, even though it was a "new technology." The court explained that "section 111 'looks toward what may fairly be projected for the regulated future, rather than the state of the art at present.'" *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (citing *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973)). The Court added that the EPA may determine that control measures are "adequately demonstrated" through a "reasonable extrapolation of [control measure's] performance in other industries." Id.

c. Costs

Under CAA section 111(a)(1), the EPA is required to take into account "the cost of achieving" the required emission reductions. As described in the January 2014 proposal for the 2015 NSPS,[162] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of

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[159] Ibid.
[160] *Sierra Club v. Costle*, 657 F.2d 298, 364 (1981).
[161] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).
[162] See 79 FR 1430, 1464 (January 8, 2014).

which would be "exorbitant,"[163] "greater than the industry could bear and survive,"[164] "excessive,"[165] or "unreasonable."[166] These formulations appear to be synonymous, and for convenience, in these rulemakings, we will use reasonableness as the standard, so that a control technology may be considered the "best system of emission reduction ... adequately demonstrated" if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.[167]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In several cases, the court upheld standards that entailed significant costs, consistent with Congress's view that "the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business."[168] *See Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 440

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[163] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).
[164] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).
[165] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).
[166] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).
[167] These cost formulations are consistent with the legislative history of CAA section 111. The 1977 House Committee Report noted:

> In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

> The implicit consideration of economic factors in determining whether technology is "available" should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91-1196 at 16.
[168] 1977 House Committee Report at 184.

(D.C. Cir. 1973);[169] *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club v. Costle*, 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the "cost of the new controls ... is substantial").[170]

d. Non-air Quality Health and Environmental Impact and Energy Requirements

Under CAA section 111(a)(1), the EPA is required to take into account "any nonair quality health and environmental impact and energy requirements" in determining the BSER. Non-air quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls, or requirements of the air pollution control equipment for water. *Portland Cement Ass'n v. Ruckelshaus*, 465 F.2d 375, 387–88 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974). Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.

e. Sector or Nationwide Component of Factors In Determining the BSER

Another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[171] The D.C. Circuit based this interpretation—which it made in the 1981 *Sierra Club v. Costle* case regarding the NSPS for new power plants—on a review of the legislative history, stating,

[T]he Reports from both Houses on the Senate and House bills illustrate very

[169] The costs for these standards were described in the rulemakings. See 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).
[170] Indeed, in upholding the EPA's consideration of costs under other provisions requiring consideration of cost, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n v. EPA*, 870 F.2d 177, 251 (5th Cir. 1989); *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries v. EPA,* 615 F.2d 794, 808 (9th Cir. 1980).
[171] See 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club v. Costle*, 657 F.2d at 351).

> clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[172]

The court has upheld EPA rules that the EPA "justified ... in terms of the policies of the Act," including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties.... By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[173]

The EPA interprets this caselaw to authorize it to assess the impacts of the controls it is considering as the BSER, including their costs and implications for the energy system, on a sector-wide, regional, or national basis, as appropriate. For example, the EPA may assess whether controls it is considering would create risks to the reliability of the electricity system in a particular area or nationwide and, if they would, to reject those controls as the BSER.

f. "Best"

In determining which adequately demonstrated system of emission reduction is the "best," the D.C. Circuit has made clear that the EPA has broad discretion. Specifically, in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), the court explained that "section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,"[174] and emphasized

[172] *Sierra Club v. Costle*, 657 F.2d at 331 (citations omitted) (citing legislative history).
[173] *Sierra Club v. Costle*, 657 F.2d at 327-28 (quoting 44 FR 33583-33584; June 11, 1979). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club v. Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. See 79 FR 1430, 1466 (January 8, 2014).
[174] *Sierra Club v. Costle*, 657 F.2d at 319.

that "[t]he text gives the EPA broad discretion to weigh different factors in setting the standard."[175] In *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999), the court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them…. EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant…. EPA [has] considerable discretion under section 111.[176]

Moreover, the D.C. Circuit has also read "best" to authorize the EPA to consider factors in addition to the ones enumerated in CAA section 111(a)(1), that further the goals of the statute. *See Portland Cement Ass'n v. Ruckelshaus* 486 F.2d 375, 385 & n.42 (D.C. Cir. 1973) (prior to enactment of the 1977 CAA Amendments that added a reference to non-air quality environmental impacts, court states that the EPA must consider "counter-productive environmental effects" in determining BSER); *Sierra Club v. Costle*, 657 F.2d 298, 326, 346-47 (D.C. Cir. 1981) (EPA should consider the amount of emission reductions and technology advancement in determining BSER).

g. Amount of Emissions Reductions

Although the definition of "standard of performance" does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved

[175] *Sierra Club v. Costle*, 657 F.2d at 321; *see also New York v. Reilly*, 969 F.2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, "the Administrator is free to exercise [her] discretion" in promulgating an NSPS).

[176] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). *See New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992) ("Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area."); *see also NRDC v. EPA*, 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because "neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decisionmaking.").

as factors the EPA must consider in determining the "best system of emission reduction," that consideration is implicit in the plain language—the EPA must choose the *best* system of *emission reduction*. Indeed, consistent with this plain language and the purpose of CAA section 111, the D.C. Circuit has stated that the EPA must consider the quantity of emissions at issue. *See Sierra Club v. Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) ("we can think of no sensible interpretation of the statutory words "best ... system" which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling … emissions").[177] The fact that the purpose of a "system of emission reduction" is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the court's view that in determining whether a "system of emission reduction" is the "best," the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term "system of emission reduction" or the term "best" may reasonably be read to allow that discretion.

h. Expanded Use and Development of Technology

The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the "best system of emission reduction." *See Sierra Club v. Costle*, 657 F.2d at 346–47. The court has grounded its reading in the statutory

[177] *Sierra Club v. Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of "standard of performance," which revised the phrase "best system of emission reduction" to read, "best technological system of continuous emission reduction." As noted above, the 1990 CAAA deleted "technological" and "continuous" and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club v. Costle* to require consideration of the amount of air emissions remains valid for the 1990 CAAA phrase "best system of emission reduction."

text.[178] In addition, the court's interpretation finds firm support in the legislative history.[179] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) the development of technology that may be treated as the "best system of emission reduction … adequately demonstrated;" under CAA section 111(a)(1);[180] (ii) the expanded use of the best demonstrated technology;[181] and (iii) the development of emerging technology.[182] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it because technological innovation may be considered an element of the term "best," particularly in light of Congress's emphasis on technological innovation.

i. Achievability of the Degree of Emission Limitation

For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish "standards of performance," which are standards for emissions that reflect the degree of

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[178] *Sierra Club v. Costle*, 657 F.2d at 346 ("Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.").

[179] See S. Rep. No. 91-1196 at 16 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources"); S. Rep. No. 95-127 at 17 (1977) (cited in *Sierra Club v. Costle*, 657 F.2d at 346 n. 174) ("The section 111 Standards of Performance ... sought to assure the use of available technology and to stimulate the development of new technology").

[180] *See Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must "look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present").

[181] See 1970 Senate Committee Report No. 91-1196 at 15 ("The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems").

[182] *See Sierra Club v. Costle*, 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

emission limitation that is "achievable" through the application of the BSER. According to the D.C. Circuit, a standard of performance is "achievable" if a technology can reasonably be projected to be available to an individual source at the time it is constructed that will allow it to meet the standard.[183] Moreover, according to the court, "[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."[184] To be achievable, a standard "must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance."[185] To show a standard is achievable, the EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[186]

Although the D.C. Circuit established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance, the same standards for achievability should apply under CAA section 111(d). For existing sources, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include

[183] *Sierra Club v. Costle*, 657 F.2d 298, 364, n. 276 (D.C. Cir. 1981).
[184] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974).
[185] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).
[186] *Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the "'feedstock, operation, size and age' of the source." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to "generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

"standards of performance." As the Supreme Court has recognized, this provision requires the EPA to promulgate emission guidelines that determine the BSER for a source category and then identify the degree of emission limitation achievable by application of the BSER. *See West Virginia v. EPA*, 142 S. Ct. 2587, 2601-02 (2022).[187]

The EPA has promulgated emission guidelines on the basis that the existing sources can achieve the degree of emission limitation described herein, even though the state retains discretion to apply standards of performance to individual sources that are more or less stringent. Note further that this requirement that the emission limitation be "achievable" based on the "best system of emission reduction ... adequately demonstrated" indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible.

3. EPA Promulgation of Emission Guidelines for States to Establish Standards of Performance

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a CAA section 110-like procedure under which states submit state plans that establish "standards of performance" for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under CAA section 111(b), and that implement and enforce those standards of performance. The term "standard of performance" is defined under CAA section 111(a)(1), quoted above. Thus, CAA sections 111(a)(1) and (d)(1) collectively require the EPA to determine the BSER for the existing sources and, based on the BSER, to establish emission guidelines that identify the minimum amount of emission limitation that a state, in its state plan, must impose on its existing sources through standards of performance. Consistent with these CAA requirements, the EPA's regulations require that the EPA's guidelines reflect--

> the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction

[187] 40 CFR 60.21(e), 60.21a(e).

> and any non-air quality health and environmental impact and energy requirements) the Administrator has determined has been adequately demonstrated from designated facilities.[188]

Following the EPA's promulgation of emission guidelines, each state must determine the standards of performance for its existing sources, which the EPA's regulations call "designated facilities."[189] While the EPA specifies in emission guidelines the degree of emission limitation achievable through application of the best system of emission reduction, which it may express as a presumptive standard of performance, a state retains discretion in applying such a presumptive standard of performance to any particular designated facility. CAA section 111(d)(1) requires the EPA's regulations to "permit the State in applying a standard of performance to any particular source ... to take into consideration, among other factors, the remaining useful life of the ... source...." Consistent with this statutory direction, the EPA's regulations provide requirements for states that wish to apply standards of performance that deviate from an emission guideline. In December 2022, the EPA proposed to clarify these requirements, including the three circumstances under which states can invoke a particular source's remaining useful life and other factors (RULOF), to apply a less stringent standard of performance. These proposed clarifications provided:

> The State may apply a standard of performance to a particular source that is less stringent than otherwise required by an applicable emission guideline, taking into consideration remaining useful life and other factors, provided that the State demonstrates with respect to each such facility (or class of such facilities) that it cannot reasonably apply the best system of emission reduction to achieve the degree of emission limitation determined by the EPA, based on:
>
> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
> (2) Physical impossibility or technical infeasibility of installing necessary control equipment; or
> (3) Other circumstances specific to the facilities (or class of facilities) that

[188] 40 CFR 60.21a(e).
[189] 40 CFR 60.21a(b), 60.24a(b).

> are fundamentally different from the information considered in the determination of the best system of emission reduction in the emission guidelines.

87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed 40 CFR 60.24a(e)).[190] In addition, under CAA sections 111(d) and 116, the state is authorized to establish a standard of performance for any particular source that is more stringent than the presumptive standards contained in the EPA's emission guidelines.[191] Thus, for any particular source, a state may apply a standard of performance that is either more stringent or less stringent than the presumptive standards of performance in the emission guidelines. The state must include the standards of performance in their state plans and submit the plans to the EPA for review.[192] Under CAA section 111(d)(2)(A), the EPA approves state plans that are determined to be "satisfactory."

VI. Stakeholder Engagement

Prior to proposing these actions, the EPA conducted outreach to a broad range of stakeholders. The EPA also opened a non-regulatory pre-proposal docket to solicit public input

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[190] The EPA intends to finalize the December 2022 proposed revisions to the CAA section 111 implementation regulations in 40 CFR part 60, subpart Ba, including any changes made in response to public comments, prior to promulgating these emission guidelines. Thus, 40 CFR part 60, subpart Ba, as revised, would apply to these emission guidelines.

[191] See 40 CFR 60.24a(f). The EPA's December 2022 proposed revisions to 40 CFR part 60, subpart Ba reflect its current interpretation that the EPA has the authority to review and approve plans that include standards of performance that are more stringent than the presumptive standards in the EPA's emission guidelines, thus making those more stringent requirements federally enforceable. 87 FR 79204 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed 40 CFR 60.24a(m), (n)). In addition, CAA section 116 authorizes the state to set standards of performance for all of its sources that, together, are more stringent than the EPA's emission guidelines.

[192] 40 CFR 60.23a. In January 2021, the D.C. Circuit Court of Appeals vacated the three-year deadline for state plan submissions of a final emission guideline in 40 CFR 60.23a(a)(1). The EPA's December 2022 proposed revisions to subpart Ba would revise 60.23a to, *inter alia*, provide for a fifteen-month submission deadline. 87 FR 79182 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed 40 CFR 60.23a(a)).

on the Agency's efforts to reduce GHG emissions from new and existing EGUs.[193] For additional details on stakeholder engagement, see the memorandum in the docket titled *Stakeholder Outreach*.

The EPA conducted two rounds of outreach to gather input for these proposals. In the first round of outreach, in early 2022, the EPA sought input in a variety of formats and settings from states, tribal nations, and a broad range of stakeholders on the state of the power sector and how the Agency's regulatory actions affect those trends. This outreach included state energy and environmental regulators; tribal air regulators; power companies and trade associations representing investor-owned utilities, rural electric cooperatives, and municipal power agencies; environmental justice and community organizations; and labor, environmental, and public health organizations. A second round of outreach took place in August and September 2022, and focused on seeking input specific to this rulemaking. The EPA asked to hear perspectives, priorities, and feedback around five guiding questions, and encouraged public input to the nonregulatory docket (Docket ID No. EPA-HQ-OAR-2022-0723) on these questions as well.

The EPA also regularly interacts with other Federal agencies and departments whose activities intersect with the power sector, and in the course of developing these proposed rules the Agency conducted multiple discussions with these agencies to benefit from their expertise and to explore the potential interaction of these proposed rules with their independent missions and initiatives. Among other things, these discussions focused on the impacts of proposed investments in energy technology by the Department of Energy and Department of Treasury on the technical and economic analyses underlying this proposal. In addition, the EPA evaluated

[193] Docket ID No. EPA-HQ-OAR-2022-0723.

structures in these proposals to address reliability considerations with the Department of Energy and Federal Energy Regulatory Commission.

VII. Proposed Requirements for New and Reconstructed Stationary Combustion Turbine EGUs and Rationale for Proposed Requirements

A. Overview

This section discusses and proposes requirements for new and reconstructed stationary combustion turbine EGUs. The EPA is proposing that those requirements will be part of a new 40 CFR part 60, subpart TTTTa. The EPA explains in section VII.B the two basic turbine technologies in use in the power sector and covered by 40 CFR part 60, subpart TTTT, simple cycle turbines and combined cycle turbines. It further explains how these technologies are used in the three general categories of low load turbines, intermediate load turbines, and base load turbines. Section VII.C provides an overview of how stationary combustion turbine EGUs have been previously regulated and how the EPA recently took comment on a proposed whitepaper on GHG mitigation options for stationary combustion turbines. Section VII.D discusses the EPA's decision to revisit the standards for turbines as part of the statutorily required 8-year review. Section VII.E discusses changes that the EPA is proposing in both applicability and subcategories in the new proposed 40 CFR part 60, subpart TTTTa as compared to those codified in 40 CFR part 60, subpart TTTT. Most notably, for natural gas-fired combustion turbines, the EPA is proposing three subcategories, a low load subcategory, an intermediate load subcategory, and a base load subcategory.

Section VII.F discusses the EPA's determination of the BSER for each of the subcategories of turbines. For low load combustion turbines, the EPA continues to believe that use of clean fuels is the appropriate BSER. For intermediate load turbines, the EPA believes that co-firing low-GHG hydrogen is an appropriate component of the BSER beginning in 2035, when the EPA projects there will be enough low-GHG hydrogen at a reasonable price to supply all of the combustion turbines that would need to use it. For this reason, the EPA is proposing a two-component BSER for intermediate load combustion turbines, and a two-phase standard of performance, in which the first phase is based on highly efficient generation (based on the performance of a highly efficient simple cycle turbine) and the second phase is based on co-firing 30 percent (by volume) low-GHG hydrogen, along with continued use of highly efficient generation.

For base load turbines, while the EPA believes CCS is available and of reasonable cost today, the EPA proposes that a two-component BSER and a two-phase standard of performance is also appropriate based on consideration of the manufacturing and installation capabilities within the larger EGU category and other industries and considerations of projected operation of combustion turbines in the future. For base load turbines, the EPA is proposing that the first phase is based on highly efficient generation (based on the performance of a highly efficient combined cycle unit) and the second phase is based on the use of either CCS with 90 percent CO_2 capture or co-firing with 30 percent (by volume) low-GHG hydrogen, depending on the subcategory, along with continued use of highly efficient generation. For both intermediate load and base load turbines, the standards corresponding to both components of the BSER would apply to all new and reconstructed sources that commence construction or reconstruction after the publication date of this proposal. The EPA occasionally refers to these standards of performance as the phase-1 or phase-2 standards.

B. Combustion Turbine Technology

For purposes of 40 CFR part 60, subparts TTTT and TTTTa, stationary combustion turbines include both simple cycle and combined cycle EGUs. Simple cycle turbines operate in the Brayton thermodynamic cycle and include three primary components: a multistage compressor, a combustion chamber (*i.e.*, combustor), and a turbine. The compressor is used to supply large volumes of high-pressure air to the combustion chamber. The combustion chamber converts fuel to heat and expands the now heated, compressed air to create shaft work. The shaft work drives an electric generator to produce electricity. Combustion turbines that recover their high-temperature exhaust—instead of venting it directly to the atmosphere—are combined cycle EGUs and can obtain additional useful electric output. A combined cycle EGU includes a heat recovery steam generator (HRSG) operating in the Rankine thermodynamic cycle. The HRSG receives the high-temperature exhaust and converts the heat to mechanical energy by producing steam that is then fed into a steam turbine that, in turn, drives a second electric generator. As the thermal efficiency of a stationary combustion turbine EGU is increased, less fuel is burned to produce the same amount of electricity, with a corresponding decrease in fuel costs and lower emissions of CO_2 and, generally, of other air pollutants. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process.

Combustion turbines serve various roles in the power sector. Some combustion turbines operate at low annual capacity factors and are available to provide temporary power during periods of high load demand. These turbines are often referred to as “peaking units.” Some combustion turbines operate at intermediate annual capacity factors and are often referred to as cycling or load-following units. Other combustion turbines operate at high annual capacity factors to serve base load demand and are often referred to as base load units. In this proposal, the EPA refers to these types of combustion turbines as low load, intermediate load, and base load, respectively.

Low load combustion turbines provide reserve capacity, support grid reliability, and generally provide power during periods of peak electric demand. As such, the units may operate at or near their full capacity, but only for short periods, as needed. Because these units only operate occasionally, capital expenses are a major factor in the cost of electricity, and often, the lowest capital cost (and generally least efficient) simple cycle EGUs are used only during periods of peak electric demand. This is because even though their capital cost is low they are inefficient and require more fuel per MWh produced and, thus, their operating costs tend to be higher. Because of the higher operating costs, they are generally some of the last units in the dispatch order. Important characteristics for low load combustion turbines include their low capital costs, their ability to start and quickly ramp to full load, and their ability to operate at partial loads while maintaining acceptable emission rates and efficiencies. The ability to start and quickly attain full load is important to maximize revenue during periods of peak electric prices and to meet sudden shifts in demand. Simple cycle combustion turbines typically fill this role even though they are less efficient and have higher fuel costs per kilowatt hour (kWh) than combined cycle EGUs, which due to their higher efficiencies, often operate at higher capacity factors, including at base load.

Highly efficient simple cycle turbines and fast-start combined cycle turbines both offer different advantages and disadvantages when operating at intermediate loads. One of the roles of these intermediate, or load-following, EGUs is to provide dispatchable backup power to support variable renewable generating sources. A developer’s decision of whether to build a simple cycle combustion turbine or a combined cycle combustion turbine to serve intermediate load demand would be based on several factors related to the intended operation of the unit. These factors include how frequently the unit is expected to cycle between starts and stops, the predominant load level at which the unit is expected to operate, and whether this level of operation is expected to remain consistent or is expected to vary over the lifetime of the unit. While the owner/operator of an individual combustion turbine controls whether and how that unit will operate over time, they do not necessarily control the precise timing of dispatch for the unit in any given day or hour. Such short-term dispatch decisions are often made by regional grid operators that determine, on a moment-to-moment basis, which available individual units should operate to balance supply and demand and other requirements in an optimal manner., based on operating costs, price bids, and/or operational characteristics. However, operating permits for simple cycle turbines often contain restrictions on the annual hours of operation which owners/operators incorporate into longer term operating plans and short-term dispatch decisions.

Intermediate load combustion turbines vary their generation, especially during transition periods between low and high electric demand. Both high-efficiency simple cycle combustion turbines and fast-start combined cycle combustion turbines can fill this cycling role. While the ability to start and quickly ramp is important, efficiency is also an important characteristic. These combustion turbines have higher capital costs than low load combustion turbines but are less expensive to operate.

Base load combustion turbines are designed to operate for extended periods at high loads with infrequent starts and stops. Quick start capability and low capital costs are less important than low operating costs. High-efficiency combined cycle combustion turbines typically fill the role of base load combustion turbines.

The increase in generation from variable renewable energy sources during the past decade has impacted the way in which firm dispatchable generating resources operate. For example, the electric output from wind and solar generating sources fluctuates daily and seasonally due to increases and decreases in the wind speed or solar intensity. Due to this intermittent nature of wind and solar, firm dispatchable electric generating units need to be available to ensure the reliability of the electric grid. This requires technologies such as dispatchable power plants to start and stop and change load more frequently than was previously needed. Important characteristics of combustion turbines that provide firm backup capacity are the ability to start and stop quickly and the ability to quickly change loads. Natural gas-fired combustion turbines are much more flexible than coal-fired utility boilers in this regard and have played an important role in ensuring electric supply and demand are in balance during the past decade.

As discussed in section IV.F.2 of this preamble and in the accompanying RIA, the post-IRA 2022 reference case projects that natural gas-fired combustion turbines will continue to play an important role in maintaining grid reliability. However, that role is projected to evolve as additional renewable and non-renewable carbon-free generation and energy storage technologies are added to the grid. Energy storage technologies would have a greater ability to store energy during periods when generation from renewable resources is high relative to demand and provide electricity to the grid during other periods. This could reduce the need for fossil fuel-fired firm dispatchable power plants to start and stop as frequently. Consequently, in the future, natural gas-fired stationary combustion turbine EGUs may run at more stable operation and, thus, more efficiently (*i.e.*, at higher duty cycles and for longer periods of operation per start). The EPA is soliciting comment on whether this a likely scenario.

C. Overview of Regulation of Stationary Combustion Turbines for GHGs

As explained earlier in this preamble, the EPA originally regulated stationary combustion turbine EGUs for emissions of GHGs in 2015 under 40 CFR part 60, subpart TTTT. In 40 CFR part 60, subpart TTTT, the EPA created three subcategories, two for natural gas-fired combustion turbines and one for multi-fuel-fired combustion turbines. For natural gas-fired turbines, the EPA created a subcategory for base load turbines and a separate subcategory for non-base load turbines. Base load turbines were defined as combustion turbines with electric sales greater than a site-specific electric sales threshold that is based on the design efficiency of the combustion turbine. Non-base load turbines were defined as combustion turbines with a capacity factor less than or equal to the site-specific electric sales threshold. For base load turbines, the EPA set a standard of 1,000 lb CO_2/MWh-gross based on efficient combined cycle turbine technology and for non-base load and multi-fuel-fired turbines, the EPA set a standard based on the use of clean fuels that varied from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending upon whether the turbine burned primarily natural gas or other clean fuels.

On April 21, 2022, the EPA issued an informational draft white paper, titled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*.[194] The draft document included discussion of the basic types of available stationary combustion turbines as well as factors that influence GHG emission rates from these sources. The technology discussion in the draft white paper included information on an array of new and existing control technologies and potential reduction measures for GHG emissions. These reduction measures included: the GHG reduction potential of various efficiency

[194] See *https://www.epa.gov/stationary-sources-air-pollution/white-paper-available-and-emerging-technologies-reducing*.

improvements; technologies capable of firing or co-firing alternative fuels such as hydrogen; the ongoing advancement of CCS projects with NGCC units; and, the co-location of technologies that do not emit onsite GHG emissions with EGUs, such as onsite renewables or short-duration energy storage.

The EPA provided an opportunity for the public to comment on this white paper to inform its approach to this proposed rulemaking. More than 30 groups or individuals provided public comments on the topics and technologies discussed in the draft white paper. Commenters included representatives from utilities, technology providers, trade associations, states, regulatory agencies, environmental groups, and public health advocates. The information provided in the public comments was beneficial in enabling the EPA to review the current NSPS for new stationary combustion turbines and to develop the proposed revisions described in this preamble.

D. Eight-Year Review of NSPS

CAA section 111(b)(1)(B) requires the Administrator to "at least every 8 years, review and, if appropriate, revise [the NSPS] …" The provision further provides that "the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such [NSPS]."

The EPA promulgated the NSPS for GHG emissions for stationary combustion turbines in 2015. Announcements and modeling projections show companies are building new fossil fuel-fired combustion turbines and plan to continue building additional capacity. Because the emissions from this capacity have the potential to be large and these units are likely to have long lives (25 years or more), the EPA believes it is important to consider options to reduce emissions from these new units. In addition, the EPA is aware of developments concerning the types of control measures that may be available to reduce GHG emissions from new stationary combustion turbines. Accordingly, the EPA is proceeding to review and is proposing updated NSPS for newly constructed and reconstructed fossil fuel-fired stationary combustion turbines.

E. Applicability Requirements and Subcategorization

This section describes the proposed amendments to the specific applicability criteria for non-fossil fuel-fired combustion turbines, industrial combustion turbines, CHP combustion turbines, and combustion turbines not connected to a natural gas pipeline and the proposed amendments to the subcategories based on the level of electric sales. The EPA is also proposing certain changes to the applicability requirements for stationary combustion turbines affected by this proposal as compared to those for sources affected by the 2015 NSPS. The proposed changes are described below and include the elimination of the multi-fuel-fired subcategory, further binning non-base load combustion turbines into low and intermediate load subcategories, and lowering the electric sales threshold for base load combustion turbines.

1. Applicability Requirements

In general, the EPA refers to fossil fuel-fired EGUs that would be subject to a CAA section 111 NSPS as "affected" EGUs or units. An EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.*, a utility boiler or IGCC unit) or stationary combustion turbine (in either simple cycle or combined cycle configuration). To be considered an affected EGU under the current NSPS at 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must: (i) be capable of combusting more than 250 million British thermal units per hour (MMBtu/h) (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (ii) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.*, for sale to the grid).[195] However, 40 CFR part 60, subpart TTTT includes applicability exemptions for certain EGUs, including: (1) non-fossil fuel-fired units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) CHP units that are subject to a federally enforceable permit limiting annual net electric sales to no more than either the unit's design efficiency multiplied by its potential electric output, or 219,000 megawatt-hours (MWh), whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.*, those that are not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.*, limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (6) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (7) certain projects under development, as discussed below.

a. Revisions to 40 CFR Part 60, Subpart TTTT

The EPA is proposing to amend 40 CFR 60.5508 and 60.5509 to reflect that 40 CFR part 60, subpart TTTT will remain applicable to steam generating EGUs and IGCC units constructed after January 8, 2014 or reconstructed after June 18, 2014. The EPA is also proposing that stationary combustion turbines that commenced construction after January 8, 2014 or reconstruction after June 18, 2014 and before [**INSERT DATE OF PUBLICATION IN**

[195] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the "base load rating criterion." Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

FEDERAL REGISTER] that meet the relevant applicability criteria would be subject to 40 CFR part 60, subpart TTTT. Upon promulgation of 40 CFR part 60, subpart TTTTa, stationary combustion turbines that commence construction or reconstruction after [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**] and meet the relevant applicability criteria will be subject to 40 CFR part 60, subpart TTTTa.

b. Revisions to 40 CFR Part 60, Subpart TTTT that would also be included in 40 CFR Part 60, Subpart TTTTa

The EPA is proposing that 40 CFR part 60, subpart TTTT and 40 CFR part 60, subpart TTTTa use similar regulatory text except where specifically stated. This section describes proposed amendments that would be included in both subparts.

i. Applicability to Non-fossil Fuel-fired EGUs

The current non-fossil applicability exemption in 40 CFR part 60, subpart TTTT is based strictly on the combustion of non-fossil fuels (*e.g.*, biomass). To be considered a non-fossil fuel-fired EGU, the EGU must both (1) be capable of combusting more than 50 percent non-fossil fuel and (2) be subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less. The current language does not take heat input from non-combustion sources (*e.g.*, solar thermal) into account. Certain solar thermal installations have natural gas backup burners larger than 250 MMBtu/h. As currently written, these solar thermal installations would not be eligible to be considered non-fossil units because they are not capable of deriving more than 50 percent of their heat input from the combustion of non-fossil fuels. Therefore, solar thermal installations that include backup burners could meet the applicability criteria of 40 CFR part 60, subpart TTTT even if the burners are limited to an annual capacity factor of 10 percent or less. These EGUs would readily comply with the emissions standard, but the reporting and recordkeeping would increase costs for these EGUs.

The EPA is proposing several amendments to align the applicability criteria with the original intent to cover only fossil fuel-fired EGUs. This would ensure that solar thermal EGUs with natural gas backup burners, like other types of non-fossil fuel-fired units in which most of their energy is derived from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subparts TTTT or TTTTa. Amending the applicability language to include heat input derived from non-combustion sources would allow these facilities to avoid the requirements of 40 CFR part 60, subparts TTTT or TTTTa by limiting the use of the natural gas burners to less than 10 percent of the capacity factor of the backup burners. Specifically, the EPA is proposing to amend the definition of non-fossil fuel-fired EGUs from EGUs capable of "combusting 50 percent or more non-fossil fuel" to EGUs capable of "*deriving* 50 percent or more *of the heat input from* non-fossil fuel *at the base load rating.*" (emphasis added). The definition of base load rating would also be amended to include the heat input from non-combustion sources (*e.g.*, solar thermal).

The proposed amended non-fossil fuel applicability language changing "combusting" to "deriving" will ensure that 40 CFR part 60, subparts TTTT and TTTTa cover the fossil fuel-fired EGUs, properly understood, that the original rule was intended to cover, while minimizing unnecessary costs to EGUs fueled primarily by steam generated without combustion (*e.g.*, through the use of solar thermal). The corresponding change in the base load rating to include the heat input from non-combustion sources is necessary to determine the relative heat input from fossil fuel and non-fossil fuel sources.

ii. Industrial EGUs

(A) Applicability to Industrial EGUs

In simple terms, the current applicability provisions in 40 CFR part 60, subpart TTTT require that an EGU be capable of combusting more than 250 MMBtu/h of fossil fuel and be capable of selling 25 MW to a utility distribution system to be subject to 40 CFR part 60, subpart TTTT. These applicability provisions exclude industrial EGUs. However, the definition of an EGU also includes "integrated equipment that provides electricity or useful thermal output." This language facilitates the integration of non-emitting generation and avoids energy inputs from non-affected facilities being used in the emission calculation without also considering the emissions of those facilities (*e.g.*, an auxiliary boiler providing steam to a primary boiler). This language could result in certain large processes being included as part of the EGU and meeting the applicability criteria. For example, the high-temperature exhaust from an industrial process (*e.g.*, calcining kilns, dryer, metals processing, or carbon black production facilities) that consumes fossil fuel could be sent to a HRSG to produce electricity. If the industrial process is more than 250 MMBtu/h heat input and the electric sales exceed the applicability criteria, then the unit could be subject to 40 CFR part 60, subparts TTTT or TTTTa. This is potentially problematic for multiple reasons. First, it is difficult to determine the useful output of the EGU (*i.e.*, HRSG) since part of the useful output is included in the industrial process. In addition, the fossil fuel that is combusted might have a relatively high CO_2 emissions rate on a lb/MMBtu basis, making it problematic to meet the emissions standard. Finally, the compliance costs associated with 40 CFR part 60, subparts TTTT or TTTTa could discourage the development of environmentally beneficial projects.

To avoid these outcomes, the EPA is proposing to amend the applicability provision that exempts EGUs where greater than 50 percent of the heat input is derived from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.[196] Projects of this type provide significant environmental benefit with little if any additional emissions. Including these types of projects would result in regulatory burden without any associated environmental benefit and would discourage project development, leading to overall increases in GHG emissions.

(B) Industrial EGUs Electric Sales Threshold Permit Requirement

The current electric sales applicability exemption in 40 CFR part 60, subpart TTTT for non-CHP steam generating units includes the provision that EGUs have "*always been subject to a federally enforceable permit* limiting annual net electric sales to one-third or less of their potential electric output (*e.g.*, limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less" (emphasis added). The justification for this restriction includes that the 40 CFR part 60, subpart Da applicability language includes "constructed for the purpose of …" and the Agency concluded that the intent was defined by permit conditions (80 FR 64544; October 23, 2015). This applicability criterion is important for determining applicability with both the new source CAA section 111(b) requirements and if existing steam generating units are subject to the existing source CAA section 111(d) requirements. For steam generating units that commenced construction after September 18, 1978, the applicability of 40 CFR part 60, subpart Da, would be relatively clear by what criteria pollutant NSPS is applicable to the facility. However, for steam generating units that commenced

[196] Auxiliary equipment such as boilers or combustion turbines that provide heat or electricity to the primary EGU (including to any control equipment) would still be considered integrated equipment and included as part of the affected facility.

construction prior to September 18, 1978, or where the owner/operator determined that criteria pollutant NSPS applicability was not critical to the project (*e.g.*, emission controls were sufficient to comply with either the EGU or industrial boiler criteria pollutant NSPS), owners/operators might not have requested an electric sales permit restriction be included in the operating permit. Under the current applicability language, some onsite EGUs could be covered by the existing source CAA section 111(d) requirements even if they have never sold electricity to the grid. To avoid covering these industrial EGUs, the EPA is proposing to amend the electric sales exemption in 40 CFR part 60, subparts TTTT and TTTTa to read, "annual net-electric sales *have never exceeded one-third of its potential electric output or 219,000 MWh, whichever is greater, and is"* (the *"always been"* would be deleted) subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.*, limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less" (emphasis added). EGUs that reduce current generation would continue to be covered as long as they sold more than one-third of their potential electric output at some time in the past. The proposed revisions would simply make it possible for an owner/operator of an existing industrial EGU to provide evidence to the Administrator that the facility has never sold electricity in excess of the electricity sales threshold and to modify their permit to limit sales in the future. Without the amendment, owners/operators of any non-CHP industrial EGU capable of selling 25 MW would be subject to the existing source CAA section 111(d) requirements even if they have never sold any electricity. Therefore, the EPA is proposing the exemption to eliminate the requirement that existing industrial EGUs must have always been subject to a permit restriction limiting net electric sales.

iii. Determination of the Design Efficiency

The design efficiency (*i.e.*, the efficiency of converting thermal energy to useful energy output) of a combustion turbine is used to determine the electric sales applicability threshold and is relevant to both new and existing EGUs.[197] The sales criteria are based in part on the individual EGU design efficiency. Three methods for determining the design efficiency are currently provided in 40 CFR part 60, subpart TTTT.[198] Since the 2015 NSPS was finalized, the EPA has become aware that owners/operators of certain existing EGUs do not have records of the original design efficiency. These units are not able to readily determine whether they meet the applicability criteria and are therefore subject to the CAA section 111(d) requirements for existing sources in the same way that 111(b) sources would be able to determine if the facility meets the applicability criteria. Many of these EGUs are CHP units and it is likely they do not meet the applicability criteria. However, the language in the 2015 NSPS would require them to conduct additional testing to demonstrate this. The requirement would result in burden to the regulated community without any environmental benefit. The electricity generating market has changed, in some cases dramatically, during the lifetime of existing EGUs, especially concerning ownership. As a result of acquisitions and mergers, original EGU design efficiency documentation as well as performance guarantee results that affirmed the design efficiency, may no longer exist. Moreover, such documentation and results may not be relevant for current EGU efficiencies, as changes to original EGU configurations, upon which the original design

[197] While the EPA could specifically allow different methods to determine the design efficiency in the 111(d) existing source emission guidelines, the Agency is proposing to align the criteria for regulatory clarity.
[198] 40 CFR part 60, subpart TTTT currently lists ASME PTC 22 Gas Turbines, ASME PTC 46 Overall Plant Performance, and ISO 2314 Gas turbines acceptance tests as approved methods to determine the design efficiency.

efficiencies were based, render those original design efficiencies moot, meaning that there would be little reason to maintain former design efficiency documentation since it would not comport with the efficiency associated with current EGU configurations. As the three specified methods would rely on documentation from the original EGU configuration performance guarantee testing, and results from that documentation may no longer exist or be relevant, it is appropriate to allow other means to demonstrate EGU design efficiency. To reduce compliance burden, the EPA is proposing in 40 CFR part 60, subparts TTTT and TTTTa to allow alternative methods as approved by the Administrator on a case-by-case basis. Owners/operators of EGUs would petition the Administrator in writing to use an alternate method to determine the design efficiency. The Administrator's discretion is intentionally left broad and could extend to other American Society of Mechanical Engineers (ASME) or International Organization for Standardization (ISO) methods as well as to operating data to demonstrate the design efficiency of the EGU. The EPA is also proposing to change the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTT from "no" to "yes" and that the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTTa is "yes." This would allow the Administrator to approve alternatives to the test methods specified in 40 CFR part 60, subparts TTTT and TTTTa.

c. Applicability for 40 CFR Part 60, subpart TTTTa

This section describes proposed amendments that would only be incorporated into 40 CFR part 60, subpart TTTTa and would differ from the requirements in 40 CFR part 60, subpart TTTT.

i. Proposed Applicability

Section 111 of the CAA defines a new or modified source for purposes of a given NSPS as any stationary source that commences construction or modification after the publication of the proposed regulation. Thus, any standards of performance the Agency finalizes as part of this rulemaking will apply to EGUs that commence construction or reconstruction after the date of this proposal. (EGUs that commenced construction after the date of the proposal for the 2015 NSPS and by the date of this proposal will remain subject to the standards of performance promulgated in the 2015 NSPS). A modification is any physical change in, or change in the method of operation of, an existing source that increases the amount of any air pollutant emitted to which a standard applies.[199] The NSPS General Provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a reconstruction.[200]

The EPA is proposing the same applicability requirements in 40 CFR part 60, subpart TTTTa as the applicability requirements in 40 CFR part 60, subpart TTTT. The stationary combustion turbine must meet the following applicability criteria: The stationary combustion turbine must: (i) be capable of combusting more than 250 million British thermal units per hour (MMBtu/h) (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (ii) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.*, for sale to the grid).[201] In addition, the EPA is proposing in 40 CFR part 60, subpart TTTTa to include applicability exemptions for stationary combustion turbines that are: (1) capable of deriving 50 percent or more of the heat input from

[199] 40 CFR 60.2.
[200] 40 CFR 60.15(a).
[201] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the "base load rating criterion." Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

non-fossil fuel at the base load rating and subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less; (2) combined heat and power units subject to a federally enforceable permit condition limiting annual net-electric sales to no more than 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (3) serving a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity is 25 MW or less; (4) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (5) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (6) deriving greater than 50 percent of heat input from an industrial process that does not produce any electrical or mechanical output that is used outside the affected stationary combustion turbine.

The EPA is proposing to apply the same requirements to combustion turbines in non-continental areas (*i.e.*, Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA is proposing for comparable units in the contiguous 48 states. However, new units in non-continental and non-contiguous areas may operate on small, isolated electric grids, may operate differently from units in the contiguous 48 states, and may have limited access to certain components of the proposed BSER due to their uniquely isolated geography or infrastructure. Therefore, the EPA is soliciting comment on whether combustion turbines in non-continental and non-contiguous areas should be subject to different requirements.

ii. Applicability to CHP units

For 40 CFR part 60, subpart TTTT, owner/operators of CHP units calculate net electric sales and net energy output using an approach that includes “at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output." It is unlikely that a CHP unit with a relatively low electric output (*i.e.*, less than 20.0 percent) would meet the applicability criteria. However, if a CHP unit with less than 20.0 percent of the total output consisting of electricity were to meet the applicability criteria, the net electric sales and net energy output would be calculated the same as for a traditional non-CHP EGU. Even so, it is not clear that these CHP units would have less environmental benefit per unit of electricity produced than more traditional CHP units. For 40 CFR part 60, subpart TTTTa, the EPA is proposing to eliminate the restriction that CHP units produce at least 20.0 percent electrical or mechanical output to qualify for the CHP-specific method for calculating net electric sales and net energy output.

In the 2015 NSPS, the EPA did not issue standards of performance for certain types of sources—including industrial CHP units and CHPs that are subject to a federally enforceable permit limiting annual net electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater. For CHP units, the approach in 40 CFR part 60, subpart TTTT for determining net electric sales for applicability purposes allows the owner/operator to subtract the purchased power of the thermal host facility. The intent of the approach is to determine applicability similarly for third-party developers and CHP units owned by the thermal host facility.[202] However, as written in 40 CFR part 60, subpart TTTT, each third-party CHP unit would subtract the entire electricity use of the thermal host

[202] For contractual reasons, many developers of CHP units sell all the generated electricity to the electricity distribution grid even though in actuality a significant portion of the generated electricity is used onsite. Owners/operators of both the CHP unit and thermal host can subtract the site purchased power when determining net electric sales. Third party developers that do not own the thermal host can also subtract the purchased power of the thermal host when determining net electric sales for applicability purposes.

facility when determining its net electric sales. It is clearly not the intent of the provision to allow multiple third-party developers that serve the same thermal host to all subtract the purchased power of the thermal host facility when determining net electric sales. This would result in counting the purchased power multiple times. In addition, it is not the intent of the provision to allow a CHP developer to provide a trivial amount of useful thermal output to multiple thermal hosts and then subtract all the thermal hosts' purchased power when determining net electric sales for applicability purposes. The proposed approach in 40 CFR part 60, subpart TTTTa would set a limit to the amount of thermal host purchased power that a third-party CHP developer can subtract for electric sales when determining net electric sales equivalent to the percentage of useful thermal output provided to the host facility by the specific CHP unit. This approach would eliminate both circumvention of the intended applicability by sales of trivial amounts of useful thermal output and double counting of thermal host-purchased power.

Finally, to avoid potential double counting of electric sales, the EPA is proposing that for CHP units determining net electric sales, purchased power of the host facility would be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility.

iii. Non-natural Gas Stationary Combustion Turbines

There is currently an exemption in 40 CFR part 60, subpart TTTT for stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.*, those that are not connected to a natural gas pipeline). While combustion turbines not connected to a natural gas pipeline meet the general applicability of 40 CFR part 60, subpart TTTT, these units are not subject to any of the requirements. The EPA is proposing requirements for new and reconstructed combustion turbines that are not capable of combusting natural gas. As described in the standards of performance section, the Agency is proposing that owners/operators of combustion turbines burning fuels with a higher heat input emission rate than natural gas would adjust the natural gas-fired emissions rate by the ratio of the heat input-based emission rates. The overall result is that new stationary combustion turbines combusting fuels with higher GHG emissions rates than natural gas on a lb CO_2/MMBtu basis would have to maintain the same efficiency compared to a natural gas-fired combustion turbine and comply with an emissions standard based on the identified BSER. Therefore, the EPA is not including in 40 CFR part 60, subpart TTTTa, the exemption for stationary combustion turbines that are not physically capable of combusting natural gas.

2. Subcategories

Stationary combustion turbines are defined in the 2015 NSPS to include both simple cycle and combined cycle EGUs. In addition, 40 CFR part 60, subpart TTTT includes three subcategories for combustion turbines—natural gas-fired base load EGUs, natural gas-fired non-base load EGUs, and multi-fuel-fired EGUs. Base load EGUs are those that sell electricity in excess of the site-specific electric sales threshold to an electric distribution network on both a 12-operating-month and 3-year rolling average basis. Non-base load EGUs are those that sell electricity at or less than the site-specific electric sales threshold to an electric distribution network on both a 12-operating-month and 3-year rolling average basis. Multi-fuel-fired EGUs combust 10 percent or more (by heat input) of fuels not meeting the definition of natural gas on a 12-operating-month rolling average basis.

a. Legal Basis for Subcategorization

As noted in section V.C.1., CAA section 111(b)(2) provides that the EPA “may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing … standards [of performance].” The D.C. Circuit has held that the EPA has broad discretion in determining whether and how to subcategorize under CAA section 111(b)(2). *Lignite Energy Council v. EPA*, 198 F3d 930, 933 (D.C. Cir. 1999). As also noted in section V.C.1., in prior CAA section 111 rules, the EPA has subcategorized on numerous bases, including, among other things, fuel type and extent of utilization.

b. Electric Sales Subcategorization (Low, Intermediate, and Base Load Combustion Turbines)

As noted earlier, in the 2015 NSPS, the EPA established separate standards for natural gas-fired base load and non-base load stationary combustion turbines. The electric sales threshold distinguishing the two subcategories is based on the design efficiency of individual combustion turbines. A stationary combustion turbine qualifies as a non-base load turbine, and is thus subject to a less stringent standard of performance, if it has net electric sales equal to or less than the design efficiency of the turbine (not to exceed 50 percent) multiplied by the potential electric output (80 FR 64601; October 23, 2015). If the net electric sales exceed that level, then the combustion turbine is in the base load combustion subcategory and is subject to a more stringent standard of performance. For additional discussion on this approach, see the 2015 NSPS (80 FR 64609–12; October 23, 2015). The 2015 NSPS non-base load subcategory is broad and includes combustion turbines that assure grid reliability by providing electricity during periods of peak electric demand. These peaking turbines tend to have low annual capacity factors and sell a small amount of their potential electric output. The non-base load subcategory in the 2015 NSPS also includes combustion turbines that operate at intermediate annual capacity factors but are not considered base load EGUs. These intermediate load EGUs provide a variety of services, including providing dispatchable power to support intermittent generation from renewable sources of electricity. The need for this service has been expanding as the amount of electricity from variable renewable sources continues to grow. In the 2015 NSPS, the EPA determined the BSER for the non-base load subcategory to be the use of clean fuels (*e.g.*, natural gas and Nos. 1 and 2 fuel oils). In 2015, the EPA explained that efficient generation did not qualify as the BSER due in part to the challenge of determining an achievable output-based CO_2 emissions rate for all combustion turbines in this subcategory.

In this action, the EPA is proposing changes to the subcategories in 40 CFR part 60, subpart TTTTa that will be applicable to sources that commence construction or reconstruction after the date of this proposed rulemaking. First, the Agency is proposing the definition of design efficiency so that the heat input calculation of an EGU is based on the higher heating value (HHV) of the fuel instead of the lower heating value (LHV), as explained immediately below. It is important to note that this would have the effect of lowering the electric sales threshold. In addition, the EPA is proposing to further divide the non-base load subcategory into separate intermediate and low load subcategories.

i. Higher Heating Value as the Basis for Calculation of the Design Efficiency

The *heat rate* is the amount of energy used by an EGU to generate one kWh of electricity and is often provided in units of Btu/kWh. As the thermal efficiency of a combustion turbine EGU is increased, less fuel is burned per kWh generated and there is a corresponding decrease in emissions of CO_2 and other air pollutants. The electric energy output as a fraction of the fuel energy input expressed as a percentage is a common practice for reporting the unit's efficiency. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process. Lower heat rates are associated with more efficient power generating plants.

Efficiency can be calculated using the HHV or the LHV of the fuel. The HHV is the heating value directly determined by calorimetric measurement of the fuel in the laboratory. The LHV is calculated using a formula to account for the moisture in the combustion gas (*i.e.*, subtracting the energy required to vaporize the water in the flue gas) and is a lower value than the HHV. Consequently, the HHV efficiency for a given EGU is always lower than the corresponding LHV efficiency because the reported heat input for the HHV is larger. For U.S. pipeline natural gas, the HHV heating value is approximately 10 percent higher than the corresponding LHV heating value and varies slightly based on the actual constituent composition of the natural gas.[203] While the EPA default is to reference all technologies on a HHV basis,[204] manufacturers of combustion turbines typically use the LHV to express the efficiency of combustion turbines.[205]

Similarly, the electric energy output for an EGU can be expressed as either of two measured values. One value relates to the amount of total electric power generated by the EGU, or *gross* output. However, a portion of this electricity must be used by the EGU facility to operate the unit, including compressors, pumps, fans, electric motors, and pollution control equipment. This within-facility electrical demand, often referred to as the parasitic load or auxiliary load, reduces the amount of power that can be delivered to the transmission grid for

[203] The HHV of natural gas is 1.108 times the LHV of natural gas. Therefore, the HHV efficiency is equal to the LHV efficiency divided by 1.108. For example, an EGU with a LHV efficiency of 59.4 percent is equal to a HHV efficiency of 53.6 percent. The HHV/LHV ratio is dependent on the composition of the natural gas (*i.e.*, the percentage of each chemical species (*e.g.*, methane, ethane, propane, *etc.*)) within the pipeline and will slightly move the ratio.
[204] Natural gas is also sold on a HHV basis.
[205] European plants tend to report thermal efficiency based on the LHV of the fuel rather than the HHV for both combustion turbines and steam generating EGUs. In the U.S., boiler efficiency is typically reported on a HHV basis.

distribution and sale to customers. Consequently, electric energy output may also be expressed in terms of *net* output, which reflects the EGU gross output minus its parasitic load.[206]

When using efficiency to compare the effectiveness of different combustion turbine EGU configurations and the applicable GHG emissions control technologies, it is important to ensure that all efficiencies are calculated using the same type of heating value (*i.e.*, HHV or LHV) and the same basis of electric energy output (*i.e.*, MWh-gross or MWh-net). Most emissions data are available on a gross output basis and the EPA is proposing output-based standards based on gross output. However, to recognize the superior environmental benefit of minimizing auxiliary loads, the Agency is proposing to include optional equivalent standards on a net output basis.

ii. Lowering the Threshold Between the Base Load and Non-Base Load Subcategories

The subpart TTTT distinction between a base load and non-base load combustion turbine is determined by the unit's actual electric sales relative to its potential electric sales, assuming the EGU is operated continuously (*i.e*., percent electric sales). Specifically, stationary combustion turbines qualify as non-base load, and thus for a less stringent standard of performance, if they have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). Because the electric sales threshold is based in part on the design efficiency of the EGU, more efficient combustion turbine EGUs can sell a higher percentage of their potential electric output while remaining in the non-base load subcategory. This approach both recognizes the

[206] It is important to note that net output values reflect the net output delivered to the electric grid and not the net output delivered to the end user. Electricity is lost as it is transmitted from the point of generation to the end user and these "line loses" increase the farther the power is transmitted. 40 CFR part 60, subpart TTTT provides a way to account for the environmental benefit of reduced line losses by crediting CHP EGUs, which are typically located close to large electric load centers. See 40 CFR 60.5540(a)(5)(i) and the definitions of gross energy output and net energy output in 40 CFR 60.5580.

environmental benefit of combustion turbines with higher design efficiencies and provides flexibility to the regulated community. In the 2015 NSPS, it was unclear how often high-efficiency simple cycle EGUs would be called upon to support increased generation from variable renewable generating resources. Therefore, the Agency determined it was appropriate to provide maximum flexibility to the regulated community. To do this, the Agency based the numeric value of the design efficiency, which is used to calculate the electric sales threshold, on the LHV efficiency. This had the impact of allowing combustion turbines to sell a greater share of their potential electric output while remaining in the non-base load subcategory.

For the reasons noted below, the EPA is proposing in 40 CFR part 60, subpart TTTTa that the design efficiency to be based on the HHV efficiency instead of LHV efficiency. The EPA is also proposing to eliminate the restriction of 50 percent limit on the design efficiency used to determine the electric sales threshold. By basing the electric sales threshold on the HHV design efficiency, the restriction is no longer necessary. If this restriction were maintained, it would reduce the regulatory incentive for manufacturers to invest in programs to develop higher efficiency combustion turbines. The EPA is also proposing to eliminate the 33 percent minimum design efficiency in the calculation of the potential electric output. The EPA is unaware of any new combustion turbines with design efficiencies of less than 33 percent; and this will likely have no cost or emissions impact. However, this provides assurance that new combustion turbines will maximize design efficiencies. Because of this relationship between the electric sales threshold and the design efficiency of an individual EGU, the proposed definition of design efficiency would have the effect of lowering the electric sales threshold between the base load and non-base load subcategories. For combined cycle EGUs, the current base load electric sales threshold is 55 percent.[207] Proposing the definition of the design efficiency to be based on HHV would make the base load electric sales threshold for combined cycle EGUs between 46 and 55 percent.[208] The current electric sales threshold for simple cycle turbines (*i.e.*, non-base load) peaks in a range of 40 to 49 percent of potential electric sales. Under the proposed definition, simple cycle turbines would be able to sell no more than between 33 and 40 percent of their potential electric output without moving into the base load subcategory. A design efficiency definition based on the HHV will have the effect of decreasing the electric sales threshold in relative terms by 19 percent and absolute terms by 7 to 9 percent.[209] The EPA is soliciting comment on whether the intermediate/base load electric sales threshold should be reduced further. The EPA is considering a range that would lower the base load electric sales threshold for simple cycle combustion turbines to between 29 to 35 percent (depending on the design efficiency) and to between 40 to 49 percent for combined cycle combustion turbines (depending on the design efficiency). This would be equivalent to reducing the design efficiency by 6 percent (*e.g.*, multiplying by 0.94) when determining the electric sales threshold.

The EPA determined that proposing to lower the electric sales threshold is appropriate for new combustion turbines because, as will be discussed later, the first component of BSER for both intermediate load and base load turbines is based on highly efficient generation. Combined

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[207] While the design efficiency is capped at 50 percent on a LHV basis, the base load rating (maximum heat input of the combustion turbine) is on a HHV basis. This mixture of LHV and HHV results in the electric sales threshold being 11 percent higher than the design efficiency. The design efficiency of all new combined cycle EGUs exceed 50 percent on a LHV basis.

[208] The electric sales threshold for combined cycle EGUs with the highest design efficiencies would remain at 55 percent.

[209] The design efficiency appears twice in the equation used to determine the electric sales threshold. Amending the design efficiency to use the HHV numeric value results in a larger reduction in the electric sales threshold than the difference between the HHV and LHV design efficiency.

cycle units are significantly more efficient than simple cycle turbines; and therefore, in general, the EPA should be focusing its determination of the BSER for base load units on that more efficient technology. In the 2015 NSPS, the EPA used a higher sales threshold because of the argument that less efficient simple cycle turbine technology served a unique role that could not be served by more efficient combined cycle technology. At the time, the EPA determined that a BSER based exclusively on that more efficient technology could exclude the building of simple cycle turbines that are needed to maintain electric reliability. With improvements to the ramp rates for combined cycle units and with integrated renewable/energy storage projects becoming more common, these less efficient simple cycle turbines are no longer the only technology that can serve this purpose. Further, as EGUs operate more, they have more hours of steady state operation relative to hours of startup/cycling. Amending the electric sales threshold would result in GHG reductions by assuring that the most efficient generating and lowest emitting combustion turbine technology is used for each subcategory. Therefore, the proposed change to calculate the design efficiency on a HHV basis will result in additional emission reductions at reasonable costs.

Based on EIA 2022 model plants, combined cycle EGUs have a lower levelized cost of electricity (LCOE) at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the proposed base load electric threshold of 40 percent for simple cycle turbines because it would be cost effective for owners/operators of simple cycle turbines to add heat recovery if they elected to operate their unit as a base load unit Furthermore, based on an analysis of monthly emission rates, recently constructed combined cycle EGUs maintain a 12-operating-month emissions rates at 12-operating-month capacity factors of less than 55 percent (the base load electric sales threshold in subpart TTTT) relative to operation at higher capacity factors. Therefore, the base load subcategory operating range could be expanded in subpart TTTTa without impacting the stringency of the numeric standard. However, at 12-operating-month capacity factors of less than approximately 50 percent, emission rates of combined cycle EGUs increase relative to operation at a higher capacity factor. It takes longer for a HRSG to begin producing steam that can be used to generate additional electricity than the time it takes a combustion engine to reach full power. Under operating conditions with a significant number of starts and stops, typical of intermediate and especially low load combustion turbines, there may not be enough time for the HRSG to generate steam that can be used for additional electrical generation. To maximize overall efficiency, combined cycle EGUs often use combustion turbine engines that are less efficient than the most efficient simple cycle combustion turbine engines. Under operating conditions with frequent starts and stops where the HRSG does not have sufficient time to begin generating additional electricity, a combined cycle EGU may be no more efficient than a highly efficient simple cycle EGU. Above capacity factors of approximately 40 percent, the average run time per start for combined cycle EGUs tends to increase significantly and the HRSG would be available to contribute additional electric generation. For more information on the impact of capacity factors on the emission rates of combined cycle EGUs see the TSD titled *Efficient Generation at Combustion Turbine Electric Generating Units*.

After the 2015 NSPS was finalized, some stakeholders expressed concerns about the approach for distinguishing between base load and non-base load turbines. They posited a scenario in which increased utilization of wind and solar resources, combined with low natural gas prices, would create the need for certain types of simple cycle turbines to operate for longer time periods than had been contemplated when the 2015 NSPS was being developed.

Specifically, stakeholders have claimed that in some regional electricity markets with large amounts of variable renewable generation, some of the most efficient new simple cycle turbines—aeroderivative turbines—could be called on to operate at capacity factors greater than their design efficiency. However, if those new simple cycle turbines were to operate at those higher capacity factors, they would become subject to the more stringent standard of performance for base load turbines. As a result, according to these stakeholders, the new aeroderivative turbines would have to curtail their generation and instead, less-efficient existing turbines would be called upon to run by the regional grid operators, which would result in overall higher emissions. The EPA evaluated the operation of simple cycle turbines in areas of the country with relatively large amounts of variable renewable generation and did not find a strong correlation between the percentage of generation from the renewable sources and the 12-operating-month capacity factors of simple cycle turbines. In addition, the vast majority of simple cycle turbines that commenced operation between 2010 and 2016 (the most recent simple cycle combustion turbines not subject to 40 CFR part 60, subpart TTTT) have operated well below the base load electric sales threshold in 40 CRF part 60, subpart TTTT. Therefore, the Agency does not believe that the concerns expressed by stakeholders necessitates any revisions to the regulatory scheme. In fact, as noted above, the EPA is proposing that the electric sales threshold can be lowered without impairing the availability of simple cycle turbines where needed, including to support the integration of variable generation. The EPA believes that the proposed threshold is not overly restrictive since a simple cycle turbine could operate on average for more than 8 hours a day,

iii. Low and Intermediate Load Subcategories

The EPA is proposing in 40 CFR part 60, subpart TTTTa to create a low load subcategory to include combustion turbines that operate only during periods of peak electric demand (*i.e.*, peaking units), to assure grid reliability, which would be separate from the intermediate load subcategory. The EPA evaluated the operation of recently constructed simple cycle turbines to understand how they operate and to determine at what electric sales level or capacity factor their emissions rate is relatively steady. (Note that for purposes of this discussion, we use the terms "electric sales" and "capacity factor" interchangeably.) Peaking units only operate for short periods of time and potentially at relatively low duty cycles.[210] This type of operation reduces the efficiency and increases the emissions rate, regardless of the design efficiency of the combustion turbine or how it is maintained. For this reason, it is difficult to establish a reasonable output-based emissions standard for peaking units.

To determine the electric sales threshold—that is, to distinguish between the intermediate load and low load subcategories—the EPA evaluated capacity factor electric sales thresholds of 10 percent, 15 percent, 20 percent, and 25 percent. The EPA found the 10 percent level problematic for two reasons. First, simple cycle combustion turbines operating at that level or lower have highly variable emission rates, and therefore it would be difficult for the EPA to establish a meaningful output-based emissions standard. In addition, only one-third of simple cycle turbines that have commenced operation since 2015 have maintained 12-operating-month capacity factors of less than 10 percent. Therefore, setting the threshold at this level would bring

[210] The duty cycle is the average operating capacity factor. For example, if an EGU operates at 75 percent of the fully rated capacity, the duty cycle would be 75 percent regardless of how often the EGU actually operates. The capacity factor is a measure of much an EGU is operated relative to how much it could potentially have been operated.

most new simple cycle turbines into the intermediate load subcategory, which would subject them to a more stringent emission rate which is only achievable for simple cycle combustion turbines operating at higher capacity factors. This could create a situation where simple cycle turbines might not be able to comply with the intermediate load emissions standard while operating at the low end of the intermediate load capacity factor subcategorization criteria.

Importantly, based on the EPA's review of hourly emissions data, above a 15 percent capacity factor, GHG emission rates begin to stabilize, see the TSD titled *Simple Cycle Stationary Combustion Turbine EGUs*, which is available in the rulemaking docket. At higher capacity factors, more time is typically spent at steady state operation rather than ramping up and down; and, emission rates tend to be lower while in steady state operation. Approximately 60 percent of recently constructed simple cycle turbines have maintained 12-operating-month capacity factors of 15 percent or less while two-thirds of recently constructed simple cycle turbines have operated at capacity factors of 20 percent or less; and, the emission rates clearly stabilize for simple cycle turbines operating at capacity factors of greater than 20 percent. Nearly 80 percent of recently constructed simple cycle turbines maintain maximum 12-operating-month capacity factors of 25 percent or less. Based on this information, the EPA is proposing the low load electric sales threshold—again, the dividing line to distinguish between the intermediate- and low-load subcategories—to be 20 percent and is soliciting comment on a range of 15 to 25 percent. The EPA is also soliciting comment on whether the low load electric sales threshold should be determined by a site-specific threshold based on three quarters of the design efficiency of the combustion turbine.[211] Under this approach, simple cycle combustion turbines selling less than 18 to 22 percent of their potential electric output (depending on the design efficiency) would still be considered low load combustion turbines. This "sliding scale" electric sales threshold approach is similar to the approach the EPA used in the 2015 NSPS to recognize the environmental benefit of installing the most efficient combustion turbines for low load applications. Using this approach, combined cycle EGUs would be able to sell between 26 to 31 percent of their potential electric output while still being considered low load combustion turbines.

Placing low load and intermediate load combustion turbines into separate subcategories is consistent with how these units are operated and how emissions from these units can be quantified and controlled. Consistent with the 2015 NSPS, the BSER analysis for base load combustion turbine EGUs assumes the use of combined cycle technology and the BSER analysis for intermediate and low load combustion turbine EGUs assumes the use of simple cycle technology. However, the Agency notes that combined cycle EGUs can elect to operate at lower levels of electric sales and be classified as intermediate or peaking EGUs. In this case, owners/operators of combined cycle EGUs would be required to comply with the emission standards for intermediate or peaking EGUs.

c. Multi-fuel-fired Combustion Turbines

40 CFR part 60, subpart TTTT subcategorizes multi-fuel-fired combustion turbines as EGUs that combust 10 percent or more of fuels not meeting the definition of natural gas on a 12-

[211] The calculation used to determine the electric sales threshold includes both the design efficiency and the base load rating. Since the base load rating stays the same when adjusting the numeric value of the design efficiency for applicability purposes, adjustments to the design efficiency has twice the impact. Specifically, using three questers of the design efficiency reduces the electric sales threshold by half.

operating-month rolling average basis. The BSER for this subcategory is the use of clean fuels with a corresponding heat input-based standard of performance of 120 to 160 lb CO_2/MMBtu, depending on the fuel, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines.[212] Clean fuels for these units include natural gas, ethylene, propane, naphtha, jet fuel kerosene, Nos. 1 and 2 fuel oils, biodiesel, and landfill gas. The definition of natural gas in 40 CFR part 60, subpart TTTT includes fuel that maintains a gaseous state at ISO conditions, is composed of 70 percent by volume or more methane, and has a heating value of between 35 and 41 megajoules (MJ) per dry standard cubic meter (dscm, m^3) (950 and 1,100 British thermal units (Btu) per dry standard cubic foot). Natural gas typically contains 95 percent methane and has a heating value of 1,050 Btu/lb.[213] A potential issue with the multi-fuel subcategory is that owners/operators of simple cycle turbines can elect to burn 10 percent non-natural gas fuels, such as Nos. 1 or 2 fuel oil, and thereby remain in that subcategory, regardless of their electric sales. As a result, they would remain subject to the less stringent standard that applies to multi-fuel-fired sources, the clean fuels standard. This could allow less efficient combustion turbine designs to operate as base load units without having to improve efficiency and could allow EGUs to avoid the need for efficient design or best operating and maintenance practices. These potential circumventions would result in higher GHG emissions.

To avoid these concerns, the EPA is proposing to eliminate the multi-fuel subcategory for low, intermediate, and base load combustion turbines in 40 CFR part 60, subpart TTTTa. This

[212] Combustion turbines co-firing natural gas with other fuels must determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas. See 80 FR 64616 (October 23, 2015).

[213] Note that 40 CFR part 60, subpart TTTT combustion turbines co-firing 25 percent hydrogen by volume could be subcategorized as multi-fuel-fired EGUs because the percent methane by volume could fall below 70 percent, the heating value could fall below 35 MJ/Sm3, and 10 percent of the heat input could be coming from a fuel not meeting the definition of natural gas.

would mean that new multi-fuel-fired turbines that commence construction or reconstruction after the date of this proposal will fall within a particular subcategory depending on their level of electric sales. The EPA also proposes that the performance standards for each subcategory be adjusted appropriately for multi-fuel-fired turbines to reflect the application of the BSER for the subcategories to turbines burning fuels with higher GHG emission rates than natural gas. To be consistent with the definition of clean fuels in the 2015 Rule, the maximum allowable heat input-based emissions rate would be 160 lb CO_2/MMBtu. For example, an emissions standard based on efficient generation would be 33 percent higher for a fuel oil-fired combustion turbine compared to a natural gas-fired combustion turbine. This would assure that the BSER, in this case efficient generation, is applied, while at the same time accounting for the use of multiple fuels. As explained in section VII.F, in the second phase of the NSPS, the EPA is proposing to further subcategorize base load combustion turbines based on whether the combustion turbine is combusting hydrogen. During the first phase of the NSPS, all base load combustion turbines would be in a single subcategory. Table 1 summarizes the proposed electric sales subcategories for combustion turbines.

Table 1—Proposed Sales Thresholds for Subcategories of Combustion Turbine EGUs

Subcategory	**Electric Sales Threshold (Percent of potential electric sales)**
Low Load	≤ 20 percent
Intermediate Load	> 20 percent and ≤ site-specific value determined based on the design efficiency of the affected facility • Between ~ 33 to 40 percent for simple cycle combustion turbines • Between ~ 45 to 55 percent for combined cycle combustion turbines
Base Load	> Site-specific value determined based on the design efficiency of the affected facility • Between ~ 33 to 40 percent for simple cycle combustion turbines • Between ~ 45 to 55 percent for combined cycle combustion turbines

F. Determination of the Best System of Emission Reduction (BSER) for New and Reconstructed Stationary Combustion Turbines

In this section, the EPA describes the controls it is proposing for the BSER for each of the subcategories of new and reconstructed combustion turbines that commence construction after the date of this proposal, and explains its basis for proposing those controls, and not others, as the BSER. The controls that the EPA is evaluating primarily include combusting non-hydrogen clean fuels (*e.g.*, natural gas and distillate oil), using highly efficient generation, using CCS, and co-firing with low-GHG hydrogen. For the low-load subcategory, the EPA is proposing the use of clean fuels as the BSER. For the intermediate load and base load subcategories, the EPA is proposing an approach under which the BSER is a set of controls that apply in two components, and that form the basis of standards of performance that apply in two phases. That is, affected facilities—which are facilities that commence construction or modification after the date of this proposed rulemaking—must meet the first phase of the standard of performance, which is based on the application of the first component of the BSER, highly efficient generation, by the date the rule is finalized; and then meet the second and more stringent phase of the standard of performance, which is based on application of the second component of the BSER, CCS or co-firing low-GHG hydrogen, along with continued application highly efficient generation, by 2035. This approach reflects the EPA's view that the BSER for the intermediate load and base load subcategories should reflect the deeper reductions in GHG emissions that can be achieved by implementing CCS and co-firing low-GHG hydrogen, but recognizes that building the infrastructure required to support wider spread use of CCS and low-GHG hydrogen in the power sector will take place on a multi-year time scale. Accordingly, newly constructed or reconstructed facilities must be aware of their need to ramp towards a more stringent phase of the standards, which reflects application of the more stringent controls in the BSER, by 2035.

Specifically, with respect to the first phase of the standards of performance, for both the intermediate load and base load subcategories, the EPA is proposing that the BSER includes constructing highly efficient generating technology—combined cycle technology for the base load subcategories and simple cycle technology for the intermediate load subcategory—as well as operating and maintaining it efficiently. The EPA sometimes refers to highly efficient generating technology in combination with the best operating and maintenance practices as highly efficient generation.

The affected sources must meet standards based on this efficient generating technology upon the effective date of the final rule. With respect to the second phase of the standards of performance, for base load combustion turbines not combusting at least 10 percent hydrogen by heat input, the BSER includes the use of CCS. Therefore, these sources would be required to meet emission standards by 2035 that reflect application of both components of the BSER – highly efficient generation and CCS – and thus are more stringent. For base load combustion turbines combusting at least 10 percent hydrogen and for intermediate load combustion turbines, the BSER includes co-firing 30 percent by volume (12 percent by heat input) low-GHG hydrogen. Therefore, these sources would be required to meet standards by 2035 that reflect the application of both components of the BSER – in this case, highly efficient generation and co-firing 30 percent low-GHG hydrogen – and, that are, again, more stringent. Table 2 summarizes the proposed BSER for combustion turbine EGUs that commence construction or reconstruction after publication of this proposal.

Table 2—Proposed BSER for Combustion Turbine EGUs

Subcategory	**Fuel**	**1st Component BSER**	**2nd Component BSER**
Low Load	All Fuels	Clean Fuels	Clean Fuels
Intermediate Load	All Fuels	Highly Efficient Generation	Low-GHG Hydrogen Co-firing
Base Load	Not combusting at least 10 percent hydrogen	Highly Efficient Generation	CCS
	Combusting at least 10 percent hydrogen		Low-GHG Hydrogen Co-firing

The EPA is also proposing standards of performance based on those BSER for each subcategory, as discussed in section VII.G.

1. BSER for Low Load Subcategory

This section describes the proposed BSER for the low load (*i.e.*, peaking) subcategory, which is the use of clean fuels. For this proposed rule, the Agency proposes to determine that the use of clean fuels, which the EPA determined to be the BSER for the non-base load subcategory in the 2015 NSPS, is the BSER for this subcategory in both phases of the standards of performance proposed in this action. As explained above, the EPA is proposing to narrow the definition of the low load subcategory by lowering the electric sales threshold (as compared to the electric sales threshold for non-base load combustion turbines in the 2015 NSPS), so that turbines with higher electric sales would be placed in the proposed intermediate load subcategory and therefore be subject to a more stringent standards based on the more stringent component of the BSER.

a. Background: The Non-base Load Subcategory in the 2015 NSPS

The 2015 NSPS defined non-base load natural gas-fired EGUs as stationary combustion turbines that (1) burn more than 90 percent natural gas and (2) have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). These are calculated on 12-operating-month and 3-year rolling average bases. The EPA also determined in the 2015 NSPS that the BSER for newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines is the use of clean fuels. Id. at 64515. These clean fuels are primarily natural gas with a small allowance for distillate oil (*i.e.*, Nos. 1 and 2 fuel oils), which have been widely used in stationary combustion turbine EGUs for decades.

The EPA also determined in the 2015 NSPS that the standard of performance for sources in this subcategory is a heat input-based standard of 120 lb CO_2/MMBtu. The EPA established this clean-fuels BSER for this subcategory because the variability in the operation in non-base load combustion turbines and the challenges involved in determining a uniform output-based standard that all new and reconstructed non-base load units could achieve.

Specifically, in the 2015 NSPS, the EPA recognized that a BSER for the non-base load subcategory based on clean fuels results in limited GHG reductions, but further recognized that an output-based emissions standard could not reasonably be applied to the subcategory. The EPA explained that a combustion turbine operating at a low capacity factor could operate with multiple starts and stops, and that its emission rate would be highly dependent on how it was operated and not its design efficiency. Moreover, combustion turbines with low annual capacity factors typically operated differently from each other, and therefore had different emission rates. The EPA recognized that, as a result, it would not be possible to determine a standard of performance that could reasonably apply to all combustion turbines in the subcategory. For that reason, the EPA further recognized, efficient design[214] and operation would not qualify as the

[214] Important characteristics for minimizing emissions from low load combustion turbines include the ability to operate efficiently while operating at part load conditions and the ability to rapidly achieve maximum efficiency to minimize periods of operation at lower efficiencies. These characteristics do not always align with higher design efficiencies that are determined under steady state full load conditions.

BSER; rather, the BSER should be clean fuels and the associated standard of performance should be based on heat input. Since the 2015 NSPS, all newly constructed simple cycle turbines have been non-base load units and thus have become subject to this standard of performance.

b. Proposed BSER

Consistent with the rationale of the 2015 NSPS, the EPA proposes that the use of clean fuels meets the BSER requirements for the low load subcategory. Use of clean fuels is technically feasible for combustion turbines. Natural gas comprises the majority of the heat input for simple cycle turbines and is the lowest cost fossil fuel. In the 2015 NSPS, the EPA determined that natural gas comprised 96 percent of the heat input for simple cycle turbines. See 80 FR 64616 (October 23, 2015). Therefore, a BSER based on the use of natural gas and/or distillate oil would have minimal, if any, costs to regulated entities. The use of clean fuels would not have any significant adverse energy requirements or non-air quality or environmental impacts, as the EPA determined in the 2015 NSPS. Id. at 64616. In addition, the use of clean fuels would result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil, as the EPA also explained in the 2015 NSPS. Id. Although the use of clean fuels would not advance technology, in light of the other reasons described here, the EPA proposes that the use of natural gas, Nos. 1 and 2 fuel oils, and other fuels[215] currently specified in 40 CFR part 60, subpart TTTT, qualify as the BSER for new and reconstructed combustion turbine EGUs in the low load subcategory. The EPA is also proposing to add hydrogen to the list of clean fuels in subpart TTTT and low-GHG hydrogen to the list of clean

[215]The BSER for multi-fuel-fired combustion turbines subject to 40 CFR part 60, subpart TTTT is also the use of clean fuels. Since the EPA is proposing to eliminate the multi-fuel-fired subcategory the use of any of all clean fuels would demonstrate compliance with the low load subcategory.

fuels in subpart TTTTa. The addition of hydrogen (and fuels derived from hydrogen) to subpart TTTT will simplify the recordkeeping and reporting requirements for non-base load combustion turbines that elect to burn hydrogen regardless of how it is derived. In contrast, the EPA would add a definition of low-GHG hydrogen in subpart TTTTa. As described in section VII.F, a component of the BSER for certain subcategories in subpart TTTTa is based on the use of low-GHG hydrogen. An owner/operator of a subpart TTTTa affected combustion turbine that combusts hydrogen not meeting the definition of low-GHG hydrogen would be in violation of the subpart TTTTa requirements.

For the reasons discussed in the 2015 NSPS and noted above, efficient design and operation cannot qualify as the BSER for the low load subcategory. The EPA is not proposing high-efficiency simple cycle or combined cycle turbine design and operation as the BSER for the low load subcategory because they are not cost-effective and would not necessarily result in emission reductions. High efficiency combustion turbines have higher initial costs compared to lower efficiency combustion turbines. The cost of combustion turbine engines is dependent upon many factors, but the EPA estimates that the capital cost of a high efficiency simple cycle turbine is 5 percent more than that for a comparable lower efficiency simple cycle turbine. Assuming all other costs are the same and that the high efficiency simple cycle turbine uses 6 percent less fuel, it would not be cost-effective to use a high efficiency simple cycle turbine until the combustion turbine is operated at a 12-operating month capacity factor of approximately 20 percent. At lower capacity factors, the CO_2 abatement costs on both a \$/ton and \$/MW basis increase rapidly.[216] Further, the emission rate of a low load combustion turbines is highly dependent upon

[216] The cost effectiveness calculation is highly dependent upon assumption on the increase in capital costs, the decrease in heat rate, and the price of natural gas.

the way the combustion turbine is operated. If the combustion turbine is frequently operated at part load conditions with frequent starts and stops, a combustion turbine with a high design efficiency, which is determined at full load steady state conditions, would not necessarily emit at a lower GHG rate than a combustion turbine with a lower design efficiency.

The EPA expects that units in the low-load subcategory will be simple cycle turbines. The capital cost of a combined cycle EGU is approximately 250 percent that of a comparable sized simple cycle EGU and would not be recovered by reduced fuel costs if operated as low load units. Furthermore, low load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation for the HRSG to begin generating steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

The EPA is not proposing the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines. As described in the section discussing the second component of BSER for the intermediate load subcategory, the EPA is not determining that CCS is the BSER for simple cycle combustion turbines based on the Agency's assessment that CCS is not cost-effective for such combustion turbines when operated at intermediate load. This rationale is even more applicable for low load combustion turbines, for that reason the Agency proposes to conclude that CCS does not qualify as the BSER for this subcategory of sources. The EPA is not proposing hydrogen co-firing as the BSER for low load combustion turbines because not all new combustion turbines can necessarily co-fire higher percentages of hydrogen and limiting the models that are available for new low load combustion turbine installations could result in increased cost to the regulated community. In addition, at the relatively infrequent levels of utilization that characterize the low load subcategory, a hydrogen co-firing BSER would not result in significant GHG reductions. Based on simple cycle turbines that recently commenced operation, the average 12-operating month capacity factor of low load combustion turbines would be less than 8 percent. Further, the majority of fuel use, and potential GHG reduction, from simple cycle combustion turbines would be from intermediate load combustion turbines.

2. BSER for Base Load and Intermediate Load Subcategories—First Component

This section describes the first component of the EPA's proposed BSER for newly constructed and reconstructed combustion turbines in the base load and intermediate load subcategories. For combustion turbines in the intermediate load subcategory, this first component of the BSER is the use of high-efficiency simple cycle turbine technology in combination with the best operating and maintenance practices. For combustion turbines in the base load subcategory, the first component of the BSER is the use of high-efficiency combined cycle technology in combination with the best operating and maintenance practices.

a. Clean Fuels

The EPA is not proposing clean fuels as the BSER for intermediate load or base load EGUs because it would achieve few emission reductions, compared to highly efficient generation.

b. Highly Efficient Generation

The use of highly efficient generating technology in combination with the best operating and maintenance practices has been demonstrated by multiple facilities for decades. Notably, over time, as technologies have improved, what is considered highly efficient has changed as well. Highly efficient generating technology is available and offered by multiple vendors for both simple cycle and combined cycle combustion turbines. Both types of turbines can also employ best operating and maintenance practices, which include routine operating and maintenance practices that minimize fuel use.

For simple cycle combustion turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. These improved designs allow for improved operating efficiencies and reduced emission rates. Design efficiencies of simple cycle combustion turbines range from 33 to 40 percent. Best operating practices for simple cycle combustion turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures.

For combined cycle turbines, high efficiency technology uses a highly efficient combustion turbine engine matched with a high-efficiency HRSG. The most efficient combined cycle EGUs use HRSG with three different steam pressures and incorporate a steam reheat cycle to maximize the efficiency of the Rankine cycle. It is not necessarily practical for owner/operators of combined cycle facilities using a turbine engine with an exhaust temperature below 593 °C or a steam turbine engine smaller than 60 MW to incorporate a steam reheat cycle. Smaller combustion turbine engines, less than those rated at approximately 2,000 MMBtu/h, tend to have lower exhaust temperatures and are paired with steam turbines of 60 MW or less. These smaller combined cycle units are limited to using triple-pressure steam without a reheat cycle. This reduces the overall efficiency of the combined cycle unit by approximately 2 percent. Therefore the EPA is proposing less stringent emission standards for smaller combined cycle EGUs with base load ratings of less than 2,000 MMBtu/h relative to those for larger combined cycle combustion turbine EGUs . High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

New technologies are available for new simple and combined cycle EGUs that could reduce emissions beyond what is currently being achieved by the best performing EGUs. For example, pressure gain combustion in the turbine engine would increase the efficiency of both simple and combined cycle EGUs. For combined cycle EGUs, the HRSG could be designed to utilize supercritical steam conditions or to utilize supercritical CO_2 as the working fluid instead of water; useful thermal output could be recovered from a compressor intercooler and boiler blowdown; and fuel preheating could be implemented. For additional information on these and other technologies that could reduce the emissions rate of new combustion turbines, see the TSD titled *Efficient Generation at Combustion Turbine Electric Generating Units*, which is available in the rulemaking docket. The EPA is soliciting comment on whether these technologies should be incorporated into a standard of performance based on an efficient generation BSER. To the extent commenters support the inclusion of emission reductions from the use of these technologies, the EPA requests that cost information and potential emission reductions be included.

i. Adequately Demonstrated

The EPA proposes that highly efficient simple cycle and combined cycle designs are adequately demonstrated because highly efficient simple cycle EGUs and highly efficient combined cycle EGUs have been demonstrated by multiple facilities for decades, the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way that the combustion turbine is operated or maintained, and the levels of efficiency that the EPA is proposing have been achieved by many recently constructed turbines.

Approximately 14 percent of simple cycle and combined cycle combustion turbines that have commenced operation since 2015 have maintained emission rates below the proposed standards, demonstrating that the efficient generation technology described in this BSER is commercially available and that the emission standards the EPA is proposing are achievable.

ii. Costs

In general, advanced generation technologies enhance operational efficiency compared to lower efficiency designs. Such technologies present little incremental capital cost compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs that offset at least a portion of the increase in capital costs.

For the intermediate load subcategory, the EPA proposes that the costs of high-efficiency simple cycle combustion turbines are reasonable. As described in the subcategory section, the cost of combustion turbine engines is dependent upon many factors, but the EPA estimates that that the capital cost of a high efficiency simple cycle turbine is 5 percent more than a comparable lower efficiency simple cycle turbine. Assuming all other costs are the same and that the high efficiency simple cycle turbine uses 6 percent less fuel, high efficiency simple cycle combustion turbines have a lower LCOE compared to standard efficiency simple cycle combustion turbine at 12-operating month capacity factor of approximately 20 percent. Therefore, a BSER based on the use of high efficiency simple cycle combustion turbines for intermediate load combustion turbines would have minimal, if any, overall compliance costs since the capital costs would be recovered through reduced fuel costs. The EPA considered, but is not proposing combined cycle unit design for combustion turbines in the intermediate subcategory because the capital cost of a combined cycle EGU is approximately 250 percent that of a comparable sized simple cycle EGU and because the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate-load EGUs is unclear. The higher capital costs of these units would not be recovered by reduced fuel costs if operated as non-base load units. Furthermore, intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

For the base load subcategory, the EPA proposes that the cost of high-efficiency combined cycle EGUs is reasonable. While the capital costs of a higher efficiency combined cycle EGUs are 1.9 percent higher than standard efficiency combined cycle EGUs, fuel use is 2.6 percent lower.[217] The reduction in fuel costs outweigh the capital costs at capacity factors of 40 percent or greater. Therefore, a BSER based on the use of high efficiency combined cycle combustion turbines for base load combustion turbines would have minimal, if any, overall compliance costs since the capital costs would be recovered through reduced fuel costs. For additional information on costs see the TSD *Efficient Generation at Combustion Turbine Electric Generating Units*, which is available in the rulemaking docket.

iii. Non-air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient simple cycle and combined cycle generation reduces all non-air quality health and environmental impacts and energy requirements as compared to use of less efficient generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result,

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[217] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022), available at: *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf*.

emissions are reduced for all pollutants. The use of highly efficient simple cycle turbines, compared to the use of less efficient simple cycle turbines, reduces all pollutants. Similarly, the use of high efficiency combined combustion turbines, compared to the use of less efficient combine cycle turbines, reduces all pollutants. By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed base load and intermediate load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA estimated the potential emission reductions associated with a standard that reflects the application of highly efficient generation as BSER for the intermediate load and base load subcategories. As discussed in section VII.G., the EPA determined that the standards of performance reflecting this BSER are 1,150 lb CO_2/MWh-gross for intermediate load and 770 lb CO_2/MWh-gross for large base load combustion turbines.

For the intermediate load subcategory, the EPA determined that the average achievable emissions rate of recently constructed high-efficiency simple cycle turbines operating at intermediate load is 1,230 lb CO_2/MWh-gross. This is 6.5 percent higher than the proposed intermediate load standard of 1,150 lb CO_2/MWh-gross. Therefore, the EPA estimates that the proposed standard of performance based on the application of the proposed BSER for intermediate load combustion turbines would reduce the GHG emissions from those sources by 6.5 percent.

For the base load subcategory, the average achievable emissions rate[218] of large (base load ratings of 2,000 MMBtu/h or more) NGCC combustion turbines that commenced operation since 2015 was 810 lb CO_2/MWh-gross. This is 5 percent higher than the proposed standard of 770 lb CO_2/MWh-gross for large base load combustion turbines. The only small, combined cycle combustion turbine (base load rating of less than 2,000 MMBtu/h) reporting emissions that commenced operation since 2015 had a reported annual emissions rate of 870 lb CO_2/MWh-gross, 4 percent higher than the proposed standard for small base load combustion turbines. Therefore, the EPA estimates that the proposed standards would require owners/operators to construct and maintain highly efficient combined cycle combustion turbines that would result in reductions in emissions of approximately 5 percent for new large stationary combustion EGUs and 4 percent for new small stationary combustion EGUs.

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient generation technology as the BSER in promoting the development and implementation of improved control technology. This technology is more efficient than the average new generation technology and determining it to be a component of the BSER will advance its penetration throughout the industry. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the first component of the BSER.

[218] The EPA is defining the achievable emissions rate as either the maximum 12-operating month or the 99th percent confidence 12-operating month emissions rate.

c. Low-GHG Hydrogen and CCS

For reasons discussed in section VII.F.3.b.v. (CCS) and VII.F.3.c.vi, the EPA is not proposing either co-firing low-GHG hydrogen or CCS as the first component of the BSER for intermediate load or base load EGUs.

d. Proposed BSER

The EPA proposes that highly efficient generating technology in combination with the best operating and maintenance practices is the first component BSER for base load and intermediate load combustion turbines and the phase 1 standards of performance are based on the application of that technology. Specifically, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices is the first component of the BSER for intermediate load combustion turbines. The use of highly efficient combined cycle technology in combination with best operating and maintenance practices is the first component of the BSER for base load combustion turbines.

Highly efficient generation qualifies as a component of the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA would consider highly efficient generation to be a component of the BSER for base load and intermediate load combustion turbines even without taking this factor into account.

3. BSER for Base Load And Intermediate Load Subcategories—Second Component

This section describes the proposed second component of the BSER for base load and intermediate load combustion turbines, which would be reflected in the second phase standards of performance that apply beginning in 2035. The proposed second component of the BSER for base load combustion turbines that are not combusting at least 10 percent hydrogen is the use of CCS. The second component of the BSER for base load combustion turbines that are combusting at least 10 percent hydrogen and for intermediate load combustion turbines is co-firing 30 percent by volume low-GHG hydrogen.

a. Authority to Promulgate a Two-part BSER and Standard of Performance

The EPA's proposed approach of promulgating standards of performance that apply in two phases, based on determining the BSER to be a set of controls with two components, is consistent with CAA section 111(b). That provision authorizes the EPA to promulgate "standards of performance," CAA section 111(b)(1)(B), defined, in the singular, as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER]." CAA section 111(a)(1). The provision further provides, "[s]tandards of performance … shall become effective upon promulgation." In this rulemaking, the EPA is proposing to determine that the BSER is a set of controls that, depending on the subcategory, include either highly efficient generation and use of CCS or highly efficient generation and co-firing low-GHG hydrogen. The EPA is further proposing that affected sources can apply the first component of the BSER (highly efficient generation) by the effective date of the final rule and can apply both the first and second components of the BSER (highly efficient generation in combination with either CCS or co-firing low GHG hydrogen) beginning in 2035. Accordingly, the EPA is proposing a standard of performance that reflects the application of this two-component BSER and that takes the form of emission standards that affected sources must comply with in two phases. Affected sources must comply with the first phase standards that are based on the application of the first component of the BSER (highly efficient generation) upon initial startup of the facility. The second phase (more stringent) standards are based on the application of both the first and second components of the BSER (highly efficient generation in combination with either use of CCS or co-firing low-GHG hydrogen) by 2035. In this manner, this two-phase standard of performance "become[s] effective upon promulgation," CAA section 111(b)(1)(B), although, as just noted, sources are not required to comply with the second and more stringent phase until 2035.

D.C. Circuit caselaw supports the proposition that CAA section 111(b) authorizes the EPA to determine that controls qualify as the BSER—including meeting the "adequately demonstrated" criterion—even if the controls require some amount of "lead time," defined as "the time in which the technology will have to be available."[219] Consistent with this caselaw, the phased implementation of the standards of performance in this rule is intended to ensure facilities have sufficient lead time for planning and implementation of the use of CCS or low GHG-hydrogen-based controls necessary to comply with the second phase of the standards, and are therefore achievable.

The EPA has promulgated several prior rulemakings under CAA section 111(b) that have similarly provided the regulated sector with lead time to accommodate the availability of technology, which also serve as precedent for the two-phase implementation approach proposed in this rule. See 81 FR 59332 (August 29, 2016) (establishing standards for municipal solid waste landfills with 30-month compliance timeframe for installation of control device, with interim milestones); 80 FR 13672, 13676 (March 16, 2015) (establishing stepped compliance approach to wood heaters standards to permit manufacturers lead time to develop, test, field

[219] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

evaluate and certify current technologies to meet Step 2 emission limits); 78 FR 58416, 58420 (September 23, 2013) (establishing multi-phased compliance deadlines for revised storage vessel standards to permit sufficient time for production of necessary supply of control devices and for trained personnel to perform installation); 70 FR 28606, 28617 (March 18, 2005) (establishing two-phase caps for mercury emission standards from new and existing coal-fired electric utility steam generating units based on timeframe when additional control technologies were projected to be adequately demonstrated).[220] *Cf.* 80 FR 64662, 64743 (October 23, 2015) (establishing interim compliance period to phase in final power sector GHG standards to allow time for planning and investment necessary for implementation activities).[221] In each action, the standards and compliance timelines were effective upon the final rule, with affected facilities required to comply consistent with the phased compliance deadline specified in each action.

It should be noted that the two-phased implementation of the standards of performance that the EPA is proposing in this rule, like the delayed or multi-phased standards in prior rules just described, is distinct from the promulgation of revised standards of performance under the 8-year review provision of CAA section 111(b)(1)(B). As discussed in section VII.F, the EPA has determined that the proposed BSER—highly efficient generation and use of CCS or highly efficient generation and co-firing low-GHG hydrogen—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being proposed. Thus, the second phase of the standard of performance, if finalized, would apply to affected facilities that commence construction after the date of this proposal. In contrast, when the EPA later reviews and (if appropriate) revises a standard of performance under the 8-year review provision, then affected

[220] *Cf. New Jersey v. EPA*, 517 F.3d 574, 583-584 (D.C. Cir. 2008) (vacating rule on other grounds).
[221] *Cf. West Virginia v. EPA*, 142 S. Ct. 2587 (2022) (vacating rule on other grounds).

sources that commence construction after the date of that proposal of the revised standard of performance would be subject to that standard, but not sources that commenced construction earlier.

Similarly, the two-phased implementation of the standard of performance that the EPA is proposing in this rule is also distinct from the promulgation of emission guidelines for existing sources under CAA section 111(d). Emission guidelines only apply to existing sources, which are defined in CAA section 111(a)(6) as “any stationary source other than a new source.” Because new sources are defined relative to the proposal of standards pursuant to CAA section 111(b)(1)(B), standards of performance adopted pursuant to emission guidelines will only apply to sources constructed before the date of these proposed standards of performance for new sources.

b. BSER for Base Load Subcategory Not Combusting At Least 10 percent Hydrogen—Second Component

This section describes the second component of the BSER for the base load subcategory not combusting at least 10 percent (by heat input) hydrogen. This subcategory is expected to include highly efficient combined cycle combustion turbines that primarily combust fossil fuels, and therefore have high levels of CO_2 in the exhaust.

The EPA is proposing the use of CCS as the second component of the BSER for these combustion turbines. A detailed discussion of CCS follows. It should be noted that the EPA is also proposing use of CCS as the BSER for existing long-term coal-fired steam generating units (*i.e.*, coal-fired utility boilers), as discussed in section X.D of this preamble. Many aspects of CCS and considerations are common to both new combined cycle combustion turbines and existing long-term steam generating units, and the following discussion details those common aspects and considerations.

i. Clean Fuels

The EPA is not proposing clean fuels as the second component of the BSER for base load combustion turbines not combusting at least 10 percent hydrogen because it would achieve few emission reductions, compared to highly efficient generation in combination with the use of CCS.

ii. Highly Efficient Generation

For the reasons described above, the EPA is proposing that highly efficient generation technology in combination with best operating and maintenance practices continues to be a component of the BSER in that is reflected in the second phase of the standards of performance for base load combustion turbine EGUs not combusting at least 10 percent hydrogen. Highly efficient generation reduces fuel use and the amount of CO_2 that must be captured by a CCS system. Since less flue gas needs to be treated, smaller carbon capture equipment may be used—potentially reducing capital, fixed, and operating costs.

iii. CCS

In this section of the preamble, the EPA provides a description of the components of CCS and evaluates it against the criteria to qualify as the BSER. CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system, such as a combustion turbine or a utility boiler. This technology is referred to as "post-combustion capture" because CO_2 is a product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure and are moved through the flue gas duct system by fans. The concentration of CO_2 in most fossil fuel combustion flue gas streams is somewhat dilute. Most post-combustion capture systems utilize liquid solvents—most commonly amine-based solvents—that separate the CO_2 from the flue gas in CO_2 scrubber systems through the use of chemical absorption (or chemisorption). In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent. The CO_2-rich solvent is then regenerated by heating the solvent to release the captured CO_2. The high purity CO_2 is then compressed and transported, generally through pipelines, to a site for geologic sequestration, or storage (*i.e.,* the long-term containment of CO_2 in subsurface geologic formations). These sequestration/storage sites are widely available across the nation, and the EPA has developed a comprehensive regulatory structure to oversee geological sequestration projects and assure their safety and effectiveness. See 80 FR 64549 (October 23, 2015).

(A) Adequately Demonstrated

For new base load combustion turbines, the EPA proposes that CCS with a 90 percent capture rate, beginning in 2035, meets the BSER criteria. This amount of CCS is feasible and has been adequately demonstrated. The use of CCS at this level can be implemented at reasonable cost because it allows affected sources to maximize the benefits of the IRC section 45Q tax credit, and sources can maintain it over time by capturing a higher percentage at certain times in order to offset a lower capture rate at other times due to, for example, the need to undertake maintenance or due to unplanned capture system outages.

The EPA previously determined "partial CCS" to be a component of the BSER (in combination with the use of a highly efficient supercritical utility boiler) for new coal-fired steam generating units as part of the 2015 NSPS (80 FR 64538; October 23, 2015). As described in that action, numerous projects demonstrate the feasibility and effectiveness of CCS technology. Additional projects since publication of that rule provide confirmation. According to the International Energy Agency's CCS database as of 2022 the CCS sector captures and stores 49.5 Million tons of CO_2 each year.

In the 2015 NSPS, the EPA considered coal-fired industrial projects that had installed at least some components of CCS technology. In doing so, the EPA recognized that some of those projects had received assistance in the form of grants, loan guarantees, and federal tax credits for investment in "clean coal technology," under provisions of the Energy Policy Act of 2005 ("EPAct05"). See 80 FR 64541–42 (October 23, 2015). (The EPA refers to projects that received assistance under that legislation as "EPAct05-assisted projects.") The EPA further recognized that the EPAct05 included provisions that constrained how the EPA could rely on EPAct05 projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111.[222] The EPA went on to provide a legal interpretation of those constraints. Under that legal interpretation, "these provisions [in the EPAct05] … preclude the EPA from relying solely

[222] The relevant EPAct05 provisions include the following: Section 402(i) of the EPAct05, codified at 42 U.S.C. 15962(a), provides as follows:
"No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . ."
IRC section 48A(g), as added by EPAct05 1307(b), provides as follows:
"No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . ."
Section 421(a) states:
"No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [*sic*] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title."

on the experience of facilities that received [EPAct05] assistance, but [do] not … preclude the EPA from relying on the experience of such facilities in conjunction with other information."[223] Id. at 64541–42. In the present action, the EPA is applying the same legal interpretation and is not reopening it for comment.

(1) CO_2 Capture Technology

The EPA is proposing that the CO_2 capture component of CCS has been adequately demonstrated and is technically feasible based on the demonstration of the technology at existing coal-fired steam generating units and industrial sources in addition to combustion turbines. While the EPA would propose that the CO_2 capture component of CCS is adequately demonstrated on those bases alone, this determination is further corroborated by EPAct05-assisted projects.

Various technologies may be used to capture CO_2, the details of which are described in the TSD titled *GHG Mitigation Measures – 111(d)*, which is available in the rulemaking docket. For post-combustion capture, these technologies include solvent-based methods (*e.g.*, amines, chilled ammonia), solid sorbent-based methods, membrane filtration, pressure-swing adsorption, and cryogenic methods.[224] Lastly, oxy-combustion uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a higher concentration of CO_2 in the flue gas, as opposed to combustion with

[223] In the 2015 NSPS, the EPA adopted several other legal interpretations of these EPAct05 provisions as well, which it is not reopening in this rule. See 80 FR 64541 (October 23, 2015).

[224] For pre-combustion capture (as is applicable to an IGCC unit), syngas produced by gasification passes through a water-gas shift catalyst to produce a gas stream with a higher concentration of hydrogen and CO_2. The higher CO_2 concentration relative to conventional combustion flue gas reduces the demands (power, heating, and cooling) of the subsequent CO_2 capture process (*e.g.*, solid sorbent-based or solvent-based capture), the treated hydrogen can then be combusted in the unit.

oxygen in air which contains 80 percent nitrogen. The CO_2 can then be separated by the aforementioned CO_2 capture methods. Of the available capture technologies, solvent-based processes have been the most widely demonstrated at commercial scale for post-combustion capture, and are applicable to use with either combustion turbines or steam generating units.

Solvent-based capture processes usually use an amine (*e.g.*, monoethanolamine, MEA). Carbon capture occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with the CO_2 but will also react with potential contaminants in the flue gas, including SO_2. After absorption, the CO_2-rich amine solution passes to the solvent regeneration column, while the treated gas passes through a water and/or acid wash column to limit emission of amines or other byproducts. In the solvent regeneration column, the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported offsite, usually by pipeline. The amine solution from the regenerating column is cooled and sent back to the absorption column, and any spent solvent is replenished with new solvent.

(2) Capture Demonstrations at Coal-fired Steam Generating Units and Industrial Processes

The function, design, and operation of post-combustion CO_2 capture equipment is similar, although not identical, for both steam generating units and combustion turbines. As a result, application of CO_2 capture at existing coal-fired steam generating units helps demonstrate the adequacy of the CO_2 capture component of CCS.

SaskPower's Boundary Dam Unit 3, a 110 MW lignite-fired unit in Saskatchewan, Canada, has demonstrated CO_2 capture rates of 90 percent using an amine-based post-combustion capture system retrofitted to the existing steam generating unit. The capture plant, which began operation in 2014, was the first full-scale CO_2 capture system retrofit on an existing coal-fired power plant. It uses the amine-based Shell CANSOLV process, with integrated heat and power from the steam generating unit.[225] While successfully demonstrating the commercial-scale feasibility of 90 percent capture rates, the plant has also provided valuable lessons learned for the next generation of capture plants. A feasibility study for SaskPower's Shand Power Station indicated achievable capture rates of 97 percent, even at lower loads.[226]

For all industrial processes, operational availability (the percent of time a unit operates relative to its planned operation) is usually less than 100 percent due to unplanned maintenance and other factors. As a first-of-a-kind commercial-scale project, Boundary Dam Unit 3 experienced some additional challenges with availability during its initial years of operation, due to the fouling of heat exchangers and issues with its CO_2 compressor.[227] However, identifying and correcting those problems has improved the operational availability of the capture system. The facility has reported greater than 90 percent capture system availability in the second and third quarters of 2022.[228] Currently, newly constructed and retrofit CO_2 capture systems are anticipated to have operational availability of around 90 percent, on the same order of that is

[225] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility–The Journey to Achieving Reliability*. Accessed at *https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191*.
[226] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. Accessed at *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf*.
[227] S&P Global Market Intelligence (January 6, 2022). *Only still-operating carbon capture project battled technical issues in 2021.* Accessed at *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/only-still-operating-carbon-capture-project-battled-technical-issues-in-2021-68302671*.
[228] SaskPower (October 18, 2022). *BD3 Status Update: Q3 2022*. Accessed at *https://www.saskpower.com/about-us/our-company/blog/2022/bd3-status-update-q3-2022*.

expected at coal-fired steam generating units. The EPA is soliciting comment on information relevant to the expected operational availability of new and retrofit CO_2 capture systems.

Several other projects have successfully demonstrated the capture component of CCS at electricity generating plants and other industrial facilities, some of which were previously noted in the discussion in the 2015 NSPS (80 FR 64548–54; October 23, 2015). Amine-based carbon capture has been demonstrated at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) coal-fired power plants, with the captured CO_2 being sold for use in the food processing industry.[229] At the 180-MW Warrior Run plant, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. AES's 320-MW coal-fired Shady Point plant captured CO_2 from an approximate 5 percent slipstream (about 66,000 metric tons of CO_2 per year) from 2001 through around 2019.[230] These facilities, which have operated for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

The capture component of CCS has also been demonstrated at other industrial processes. Since 1978, the Searles Valley Minerals soda ash plant in Trona, California, has used an amine-based system to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of a coal-fired industrial power plant that generates steam and power for onsite use. The captured CO_2 is used for the carbonation of brine in the process of producing soda ash.[231]

[229] Dooley, J. J., et al. (2009). "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." U.S. DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830.
[230] Shady Point Plant (River Valley) was sold to Oklahoma Gas and Electric in 2019. *https://www.oklahoman.com/story/business/columns/2019/05/23/oklahoma-gas-and-electric-acquires-aes-shady-point-after-federal-approval/60454346007/.*
[231] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.

The Quest CO_2 capture facility in Alberta, Canada, uses amine-based CO_2 capture retrofitted to three existing steam methane reformers at the Scotford Upgrader facility (operated by Shell Canada Energy) to capture and sequester approximately 80 percent of the CO_2 in the produced syngas.[232] The Quest facility has been operating since 2015 and captures approximately 1 million metric tons of CO_2 per year.

(3) Capture Demonstrations at Combustion Turbines

While most demonstrations of CCS have been for applications other than combustion turbines, CCS has been successfully applied to an existing combined cycle EGU and several other projects are in development. Examples of the use of CCS on combined cycle EGUs include the Bellingham Energy Center in south central Massachusetts and the proposed Peterhead Power Station in Scotland. The Bellingham plant used Fluor's Econamine FG Plus[SM] capture system and demonstrated the commercial viability of carbon capture on a combined cycle combustion turbine EGU using first-generation technology. The 40-MW slipstream capture facility operated from 1991 to 2005 and captured 85 to 95 percent of the CO_2 in the slipstream for use in the food industry.[233] In Scotland, the proposed 900-MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million tonnes of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast might serve as

[232] Quest Carbon Capture and Storage Project Annual Summary Report, Alberta Department of Energy: 2021. *https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2021*.

[233] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Accessed at *https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems*.

a destination for the captured CO_2.[234] Moreover, an 1,800-MW NGCC EGU that will be constructed in West Virginia and will utilize CCS has been announced. The project is planned to begin operation later this decade, and its feasibility was partially credited to the expanded IRC section 45Q tax credit for sequestered CO_2 provided through the IRA.[235]

In addition, there are several planned projects using the NET Power Cycle.[236] The NET Power Cycle is a proprietary process for producing electricity that combusts a fuel with purified oxygen and uses supercritical CO_2 as the working fluid instead of water/steam. This cycle is designed to achieve thermal efficiencies of up to 59 percent.[237] Potential advantages of this cycle are that it emits no NO_X and produces a stream of high-purity CO_2[238] that can be delivered by pipeline to a storage or sequestration site without extensive processing. A 50-MW (thermal) test facility in La Porte, Texas was completed in 2018 and was synchronized to the grid in 2021. There are several announced commercial projects proposing to use the NET Power Cycle. These include the 280-MW Broadwing Clean Energy Complex in Illinois, the 280-MW Coyote Clean Power Project on the Southern Ute Indian Reservation in Colorado, a 300-MW project located near Occidental's Permian Basin operations close to Odessa, Texas, and several international projects. Commercial operation of the facility near Odessa, Texas is expected in 2026.

[234] Buli, N. (2021, May 10). SSE, Equinor plan new gas power plant with carbon capture in Scotland. *Reuters*. Retrieved October 14, 2021, https://www.reuters.com/business/sustainable-business/sse-equinor-plan-new-gas-power-plant-with-carbon-capture-scotland-2021-05-11/.

[235] Competitive Power Ventures (2022). *Multi-Billion Dollar Combined Cycle Natural Gas Power Station with Carbon Capture Announced in West Virginia.* Press Release. September 16, 2022. Accessed at *https://www.cpv.com/2022/09/16/multi-billion-dollar-combined cycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.*

[236] *https://netpower.com/technology/*. The Net Power Cycle was formerly referred to as the Allam-Fetvedt cycle.

[237] Yellen, D. (2020, May 25). Allam Cycle carbon capture gas plants: 11 percent more efficient, all CO_2 captured. *Energy Post*. *https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.*

[238] This allows for capture of over 97 percent of the CO_2 emissions. *www.netpower.com*

Currently available post-combustion amine-based carbon capture systems require that the flue gas be cooled prior to entering the carbon capture equipment. This holds true for the exhaust from a combustion turbine. The most energy efficient way to do this is to use a HSRG—which, as explained above, is an integral component of a combined cycle turbine system—to generate additional useful output. Because simple cycle combustion turbines do not incorporate a HRSG, the Agency is limiting consideration of the use of CCS as a potential component of the BSER only to combined cycle combustion turbine EGUs.

(4) EPAct05-assisted CO_2 Capture Projects

While the EPA is proposing that the capture component of CCS is adequately demonstrated based solely on the other demonstrations of CO_2 capture discussed in this preamble, adequate demonstration of CO_2 capture technology is further corroborated by CO_2 capture projects assisted by grants, loan guarantees, and Federal tax credits for “clean coal technology” authorized by the EPAct05. 80 FR 64541–42 (October 23, 2015).

Petra Nova is a 240 MW-equivalent capture facility that is the first at-scale application of carbon capture at a coal-fired power plant in the U.S. The system is located at the W.A. Parish Generating Station in Thompsons, Texas, and began operation in 2017, successfully capturing and sequestering CO_2 for several years. Although the system was put into reserve shutdown (*i.e.*, idled) in May 2020, citing the poor economics of utilizing captured CO_2 for enhanced oil recovery (EOR) at that time, there are reports of plans to restart the capture system.[239] A final report from National Energy Technology (NETL) details the success of the project and what was

[239] “The World's Largest Carbon Capture Plant Gets a Second Chance in Texas” Bloomberg News, February 8, 2023, *https://www.bloomberg.com/news/articles/2023-02-08/the-world-s-largest-carbon-capture-plant-gets-a-second-chance-in-texas?leadSource=uverify%20wall*.

learned from this first-of-a-kind demonstration at scale.[240] The project used Mitsubishi Heavy Industry's proprietary KM-CDR Process®, a process that is similar to an amine-based solvent process but that uses a proprietary solvent and is optimized for CO_2 capture from a coal-fired generator's flue gas. During its operation, the project successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR. Plant Barry in Mobile, Alabama, began using the KM-CDR Process® in 2011 for a fully integrated 25-MW CCS project with a capture rate of 90 percent.[241] The CCS project at Plant Barry captured approximately 165,000 tons of CO_2 annually, which is then transported via pipeline and sequestered underground in geologic formations. See 80 FR 64552 (October 23, 2015).

(5) CO_2 Transport

The majority of CO_2 transported in the U.S. is transported through pipelines. Pipeline transport of CO_2 has been occurring for nearly 60 years, and over this time, the design, construction, and operational requirements for CO_2 pipelines have been demonstrated. Moreover, the U.S. CO_2 pipeline network has steadily expanded, and appears primed to continue to do so. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that 5,339 miles of CO_2 pipelines were in operation in 2021, a 13 percent increase in CO_2 pipeline miles since 2011.[242] Moreover, several major projects have recently been announced to expand the

[240] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). Available at *https://www.osti.gov/servlets/purl/1608572*.
[241] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). Accessed at *https://www.netl.doe.gov/node/1741*.
[242] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2021. Available online at: *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids*.

CO_2 pipeline network across the U.S. For example, the Midwest Carbon Express and Heartland Greenway have proposed to add more than a combined 1,600 miles of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, Minnesota, and Illinois. The Midwest Carbon Express is projected to begin operations in 2024 and the Heartland Greenway is projected to start its initial system commissioning in the second quarter of 2025.[243] [244] The proximity to existing or planned CO_2 pipelines and geologic sequestration sites can be a factor to consider in the construction of stationary combustion turbines, and pipeline expansion, when needed, has been proven to be feasible.

Existing and new CO_2 pipeline safety is exclusively regulated by PHMSA. These regulations include standards related to pipeline operations and maintenance, operator reporting requirements, operator qualifications, corrosion control and pipeline integrity management, incident reporting and response, and public awareness and communications. PHMSA has regulatory authority to conduct inspections of CO_2 pipeline operations and issue notices to operators in the event of operator noncompliance with regulatory requirements.[245] Furthermore, PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia,

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[243] Beach, Jeff. “World’s Largest Carbon Capture Pipeline Aims to Connect 31 Ethanol Plants, Cut across Upper Midwest.” Agweek, December 6, 2021. Available online at: *https://www.agweek.com/business/worlds-largest-carbon-capture-pipeline-aims-to-connect-31-ethanol-plants-cut-across-upper-midwest*.

[244] Navigator CO_2, “NavCO2 Fact Sheet.” 2022. Available online at: *https://d3o151.p3cdn1.secureserver.net/wp-content/uploads/2022/08/HG-Fact-Sheet-vFINAL.pdf*.

[245] See generally 49 CFR 190–199.

Mississippi in 2020.[246] Following that incident, PHMSA also issued a notice of probable violation and proposed civil penalties on the operator for probable violations of Federal pipeline safety regulations, issued an updated nationwide advisory bulletin to all pipeline operators, and solicited research proposals to strengthen CO_2 pipeline safety.[247] These CO_2 pipeline controls ensure that captured CO_2 will be securely conveyed to a sequestration site.

Transportation of CO_2 via pipeline is the most viable and cost-effective method at the scale needed for sequestration of captured EGU CO_2 emissions. However, CO_2 can also be liquified and transported via ship, road tanker, or rail tank cars when pipelines are not available. Liquefied natural gas and liquefied petroleum gases are already routinely transported via ship at a large scale, and the properties of liquified CO_2 are not significantly different.[248] In fact, the food and beverage as well as specialty gas industries already have experience transporting CO_2 by rail.[249] Road tankers and rail can transport smaller quantities of CO_2 and can be used in tandem with other modes of transportation to move CO_2 captured from an EGU.[250]

(6) Geologic Sequestration of CO_2

(a) Security of Sequestration

Geologic sequestration (or storage), which is the long-term containment of a CO_2 stream in subsurface geologic formations, is well proven and broadly available throughout the U.S.

[246] PHMSA, "PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak." 2022. Available online at: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures*.

[247] Ibid.

[248] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[249] EU CCUS Projects Network. (2019). Briefing on Carbon Dioxide Specifications for Transport. *https://www.ccusnetwork.eu/sites/default/files/TG3_Briefing-CO2-Specifications-for-Transport.pdf*.

[250] Ibid.

Geologic sequestration is based on a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. These processes can vary regionally based on differences in subsurface geology. There have been numerous efforts demonstrating successful geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2.

(i) Demonstration of Geologic Sequestration

Existing project and regulatory experience, along with other information, indicate that geologic sequestration is a viable long-term CO_2 sequestration option. The effectiveness of long-term trapping of CO_2 has been demonstrated by natural analogues in a range of geologic settings where CO_2 has remained trapped for millions of years.[251] For example, CO_2 has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi.[252] Other examples of natural CO_2 sources include the Bravo Dome and the McElmo Dome in New Mexico and Colorado, respectively.[253] These naturally occurring sequestration sites demonstrate the feasibility of containing the large volumes of CO_2 that may be captured from fossil fuel-fired EGUs, as these sites have held volumes of CO_2 that are much larger than the volume of CO_2 expected to be captured from a fossil fuel-fired EGU over the course of its useful life. In 2010, the DOE estimated CO_2 reserves of 594 million metric tons at Jackson Dome, 424 million metric

[251] Holloway, S., *et al.* Natural Emissions of CO_2 from the Geosphere and their Bearing on the Geological Storage of Carbon Dioxide. 2007. Energy 32: 1194–1201.

[252] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

253 See K.J. Sathaye, M.A. Hesse, M. Cassidy, D.F. Stockli, "Constraints on the magnitude and rate of CO_2 dissolution at Bravo Dome natural gas field." *Proceedings of the National Academy of Sciences* 111, 15332–15337. 2014. and Kinder Morgan. "Carbon Dioxide (CO_2) Operations; CO_2 Supply." Accessed December 13, 2022. Available online at: *https://www.kindermorgan.com/Operations/CO2/Index.*

tons at Bravo Dome, and 530 million metric tons at McElmo Dome.[254] Between 2000 and 2020, Department of Energy-sponsored research totaling $1B to prove carbon storage technologies and enable large-scale deployment. Research conducted by the regional carbon sequestration partnerships has demonstrated geologic sequestration through a series of field research projects that increased in scale over time, injecting more than 11 million tons of CO_2.

Numerous additional saline facilities are under development across the United States. The EPA is currently reviewing Underground Injection Control (UIC) Class VI geologic sequestration well permit applications for proposed sequestration sites in at least seven states.[255, 256] States with UIC Class VI primacy are also processing injection permits for potential saline sequestration projects. In Wyoming, Class VI permit applications have been filed for a proposed saline sequestration facility located in southwestern Wyoming. At full capacity, the facility will permanently store up to 5 million metric tons of CO_2 annually from industrial facilities in the Nugget saline sandstone reservoir.[257]

Geologic sequestration has been proven to be successful and safe in projects internationally. Facilities have geologically sequestered CO_2 for over twenty years. In Norway, facilities conduct offshore sequestration under the Norwegian continental shelf.[258] In addition,

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[254] DiPietro, P., *et al.* "A Note on Sources of CO_2 Supply for Enhanced-Oil Recovery Operations. SPE Economics & Management." 2012.
[255] UIC regulations for Class VI wells facilitate the injection of CO_2 for geologic sequestration while protecting human health and the environment by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in Section VII.F.3.b.iii.
[256] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 12, 2023. Available online at: *https://www.epa.gov/uic/class-vi-wells-permitted-epa*.
[257] Wyoming DEQ Class VI Permit Applications. Available online at: *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/.*
[258] "Injection and Geologic Sequestration of Carbon Dioxide: Federal Role and Issues for Congress." Congressional Research Service, September 22, 2022. Available online at: *https://crsreports.congress.gov/product/pdf/R/R46192*.

the Sleipner CO_2 Storage facility in the North Sea, which began operations in 1996, injects around 1 million metric tons of CO_2 per year from natural gas processing.[259] The Snohvit CO_2 Storage facility in the Barents Sea, which began operations in 2008, injects around 0.7 million metric tons of CO_2 per year from natural gas processing. The SaskPower carbon capture and storage facility at Boundary Dam Power Station in Saskatchewan, Canada had, as of mid-2022, captured 4.6 million tons of CO_2 since it began operating in 2014.[260] Other international sequestration facilities in operation include Glacier Gas Plant MCCS (Canada),[261] Quest (Canada), and Qatar LNG CCS (Qatar).

(ii) EPAct05-Assisted Geologic Sequestration Projects

While the EPA is proposing that the sequestration component of CCS is adequately demonstrated based solely on the other demonstrations of geologic sequestration discussed in this preamble, adequate demonstration of geologic sequestration is further corroborated by geologic sequestration currently operational and planned projects assisted by grants, loan guarantees, and Federal tax credits for "clean coal technology" authorized by the EPAct05. 80 FR 64541-42 (October 23, 2015).

[259] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, *et al.* "Global Status of CCS 2022." Global CCS Institute, 2022. Available online at: *https://status22.globalccsinstitute.com/2022-status-report/introduction/*.
[260] Boundary Dam Carbon Capture Project, accessed January 20, 2023. Available online at: *https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project*.
[261] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, et al. "Global Status of CCS 2022." Global CCS Institute, 2022. Available online at: *https://status22.globalccsinstitute.com*.

Two saline sequestration facilities are currently in operation in the U.S. and several are under development.[262] The Illinois Industrial Carbon Capture and Storage Project began injecting CO_2 from ethanol production into the Mount Simon Sandstone in April 2017. The project has the potential to store up to 5.5 million metric tons of CO_2,[263] and, according to the facility's report to the EPA's GHGRP, as of 2021, 2.5 million metric tons of CO_2 had been injected into the saline reservoir.[264] The Red Trail Energy CCS facility in North Dakota, which is the first saline sequestration facility in the U.S. to operate under a state-led regulatory authority for carbon storage, began injecting CO_2 from ethanol production in 2022.[265] This project is expected to inject a total of 3.7 million tons of CO_2 over its lifetime.[266]

There are additional planned geologic sequestration facilities across the United States. Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakotais projected to capture 4 million metric tons of CO_2 annually.[267] The Great Plains Synfuel Plant currently captures 2 million metric tons of CO_2 per year, which is

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[262] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, *et al.* "Global Status of CCS 2022." Global CCS Institute, 2022. Available online at: *https://status22.globalccsinstitute.com/*.
[263] Archer Daniels Midland, Monitoring, Reporting, and Verification Plan CCS#2, 2017. Available online at: *https://www.epa.gov/sites/default/files/2017-01/documents/adm_mrv_plan.pdf*.
[264] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.
[265] Zapantis, Alex, Noora Al Amer, Ian Havercroft, Ruth Ivory-Moore, Matt Steyn, Xiaoliang Yang, Ruth Gebremedhin, et al. "Global Status of CCS 2022." Global CCS Institute, 2022. Available online at: *https://status22.globalccsinstitute.com*.
[266] North Dakota Industrial Commission, NDIC Case No. 28848—Draft Permit Fact Sheet and Storage Facility Permit Application," accessed on February 16, 2022, at *https://www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp.* This injection well is permitted by North Dakota.
[267] Project Tundra. "Project Tundra." Accessed January 20, 2023. Available online at: *https://www.projecttundrand.com/*.

used for enhanced oil recovery (EOR).[268] A planned addition of saline sequestration for this facility is expected to increase the amount captured and sequestered (through both geologic sequestration and EOR) to 3.5 million metric tons of CO_2 per year.[269]

(iii) Security of Geologic Sequestration

Regulatory oversight of geologic sequestration is built upon an understanding of the proven mechanisms by which CO_2 is retained in geologic formations. These mechanisms include (1) structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).

Based on the understanding developed from natural analogs and existing projects, the security of sequestered CO_2 is expected to *increase* after injection ceases. This is due to drilling post-closure injection wells that decrease pressure[270] and to trapping mechanisms that reduce CO_2 mobility over time, *e.g.*, physical CO_2 trapping by a low-permeability geologic seal or

[268] Basin Electric Power Cooperative. "Great Plains Synfuels Plant Potential to Be Largest Coal-Based Carbon Capture and Storage Project to Use Geologic Storage," September 9, 2021. Available online at: *https://www.basinelectric.com/News-Center/news-releases/Great-Plains-Synfuels-Plant-potential-to-be-largest-coal-based-carbon-capture-and-storage-project-to-use-geologic-storage*.

[269] Basin Electric Power Cooperative. "Great Plains Synfuels Plant Potential to Be Largest Coal-Based Carbon Capture and Storage Project to Use Geologic Storage," September 9, 2021. Available online at: *https://www.basinelectric.com/News-Center/news-releases/Great-Plains-Synfuels-Plant-potential-to-be-largest-coal-based-carbon-capture-and-storage-project-to-use-geologic-storage.*

[270] "Report of the Interagency Task Force on Carbon Capture and Storage." 2010. Available online at: *https://www.osti.gov/servlets/purl/985209*.

chemical trapping by conversion or adsorption.[271] In addition, site characterization, site operations, and monitoring strategies as required through the Underground Injection Control (UIC) Program and the GHGRP, discussed below, work in combination to ensure security and transparency.

The UIC Program, the GHGRP and other regulatory requirements comprise a detailed regulatory framework for facilitating geologic sequestration in the U.S., according to a 2021 report from the Council on Environmental Quality (CEQ). This framework is already in place and capable of reviewing and permitting CCS activities.[272]

This regulatory framework includes the UIC Class VI well regulations, promulgated under the authority of the Safe Drinking Water Act (SDWA); and the GHGRP, promulgated under the authority of the CAA. The requirements of the UIC and GHGRP programs work together to ensure that sequestered CO_2 will remain securely stored underground. The UIC regulations facilitate the injection of CO_2 for geologic sequestration while protecting human health and the environment by ensuring the protection of underground sources of drinking water (USDW). These regulations are built upon decades of Federal experience regulating underground injection wells, and many additional years of state UIC program expertise. expertise. The IIJA established a program to assist states and Tribal regulatory authorities interested in Class VI primacy. EPA has indicated that it will require approaches that balance the use of geologic sequestration with mitigation of impacts on vulnerable communities. States and Tribes are asked to support communities by implementing an inclusive public participation process, considering

[271] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.
[272] CEQ. *"Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration."* 2021. Available online at: *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

environmental justice impacts on communities, enforcing Class VI regulatory protections and incorporating other mitigation measures.

To complement the UIC regulations, the EPA included in the GHGRP air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration. These requirements are included in 40 CFR part 98, subpart RR, also referred to as "GHGRP subpart RR."

The GHGRP subpart RR requirements provide the monitoring mechanisms to identify, quantify, and address potential leakage. The EPA designed them to complement and build on UIC monitoring and testing requirements. Although the regulations for the UIC program are designed to ensure protection of USDWs from endangerment, the practical effect of these GHGRP subpart RR requirements is that they also prevent releases of CO_2 to the atmosphere.

Major components to be included in UIC Class VI permits are site characterization, area of review,[273] corrective action,[274] well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure. Reporting under GHGRP subpart RR is required for, but not limited to, all facilities that have received a UIC Class VI permit for injection of CO_2.[275] GHGRP subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection;

[273] Per 40 CFR 146.84(a), the area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.
[274] UIC permitting authorities may require corrective action for existing wells within the area of review to ensure protection of underground sources of drinking water.
[275] 40 CFR 98.440.

develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[276] [277] [278] [279] Although deep subsurface monitoring is required for UIC Class VI wells at 40 CFR 146.90 and is the primary means of determining if there are any leaks to a USDW, and is generally effective in doing so, the surface air and soil gas monitoring employed under a GHGRP subpart RR MRV Plan can be utilized in addition to subsurface monitoring required under 40 CFR 146.90, if required by the UIC Program Director under 40 CFR 146.90(h), to further ensure protection of USDWs.[280] The MRV plan includes five major components: a delineation of monitoring areas based on the CO_2 plume location; an identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways; a strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs; an approach for establishing the expected baselines for monitoring CO_2 surface leakage; and, a summary of considerations made to calculate site-specific variables for the mass balance equation.[281]

(b) Broad Availability of Sequestration

Geologic sequestration potential for CO_2 is widespread and available throughout the U.S. Nearly every state in the U.S. has or is in close proximity to formations with geologic sequestration potential, including areas offshore. These areas include deep saline formation, unmineable coal seams, and oil and gas reservoirs. Moreover, the amount of storage capacity can

[276] 40 CFR 98.446.
[277] 40 CFR 98.448.
[278] 40 CFR 98.446(f)(9) and (10).
[279] 40 CFR 98.446(f)(12).
[280] See 75 FR 77263 (December 10, 2010).
[281] 40 CFR 98.448(a).

readily accommodate the amount of CO_2 for which sequestration could be required under this proposed rule.

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration capacity in the U.S. The DOE estimates are compiled in the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and are published in its Carbon Utilization and Sequestration Atlas (NETL Atlas).[282] The DOE estimates that areas of the U.S. with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs.[283] The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the U.S.[284]

With respect to deep saline formations, the DOE estimates a sequestration potential of at least 2,200 billion metric tons of CO_2 in these formations in the U.S. At least 37 states have geologic characteristics that are amenable to deep saline sequestration, and an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations.[285] [286]

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[282] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

[283] Ibid.

[284] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, National assessment of geologic carbon dioxide storage resources–Summary: U.S. Geological Survey Factsheet 2013-3020. 2013. Available online at: *https://pubs.usgs.gov/fs/2013/3020/*.

[285] Alaska has deep saline formation storage capacity, geology amenable to EOR operations, and potential geologic sequestration capacity in unmineable coal seams.

[286] The U.S. DOE NETL Carbon Storage Atlas, Fifth Edition did not assess deep saline formation potential for Alaska, Connecticut, Hawaii, Maine, Massachusetts, Nevada, New Hampshire, Rhode Island, and Vermont. We are assuming for purposes of our analysis here that they do not have storage potential in this type of formation.

Unmineable coal seams offer another potential option for geologic sequestration of CO_2. Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively "locks" the CO_2 to the coal, where it remains stored. States with the potential for sequestration in unmineable coal seams include Iowa and Missouri, which have little to no saline sequestration potential and have existing coal-fired EGUs. Unmineable coal seams have a sequestration potential of 54 billion metric tons of CO_2, or 2 percent of total potential in the U.S., and are located in 22 states.[287]

The potential for CO_2 sequestration in unmineable coal seams has been demonstrated in small-scale demonstration projects, including the Allison Unit pilot project in New Mexico, which injected a total of 270,000 tons of CO_2 over a six-year period (1995–2001). Further, DOE Regional Carbon Sequestration Partnership projects have injected CO_2 volumes in unmineable coal seams ranging from 90 tons to 16,700 tons.[288] DOE has judged unmineable coal seams worthy of inclusion in the NETL Atlas.[289]

Although the large-scale injection of CO_2 in coal seams can lead to swelling of coal, the literature also suggests that there are available technologies and techniques to compensate for the

[287] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.
[288] M. Godec *et al.*, "CO_2-ECBM: A Review of its Status and Global Potential," Energy Procedia 63: 5858–5869 (2014). Available online at: *https://doi.org/10.1016/j.egypro.2014.11.619*.
[289] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition*, September 2015. Available online at: *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv*.

resulting reduction in injectivity.[290] Further, the reduced injectivity can be anticipated and accommodated in sizing and characterizing prospective sequestration sites.

There is sufficient technical basis and scientific evidence that depleted oil and gas reservoirs represent another option for geologic storage. The reservoir characteristics of older fields are well known as a result of exploration and many years of hydrocarbon production and in many areas infrastructure already exists for CO_2 transportation and storage.[291] Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO_2, and DOE is continuing to evaluate their potential sequestration capacity and efficacy.[292]

The EPA performed a geographic availability analysis in which the Agency examined areas of the country with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100-kilometer (km) (62-mile) area of locations with

[290] Xiachun Li & Zhi-Ming Fang, "Current Status and Technical Challenges of CO_2 Storage in Coal Seams and Enhanced Coalbed Methane Recovery: An Overview," International Journal of Coal Science & Technology, 93, 99 (2014) (suggesting existing technologies that can be used to address injectivity reduction in unmineable coal seams).
[291] The Texas Bureau of Economic Geology tested a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi. As part of a DOE Southeast Regional Carbon Sequestration Partnership study, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year. Texas Bureau of Economic Geology, "Cranfield Log." Available online at: *https://www.beg.utexas.edu/gccc/research/cranfield*.
[292] Goodman, A., *et al.* "Methodology for Assessing CO_2 Storage Potential of Organic-Rich Shale Formations." *Energy Procedia*, 12th International Conference on Greenhouse Gas Control Technologies, GHGT-12, 63 (2014): 5178–84. Available online at: *https://doi.org/10.1016/j.egypro.2014.11.548*. NETL DOE. "Big Sky Carbon Sequestration Partnership." Accessed November 16, 2022. Available online at: *https://netl.doe.gov/coal/carbon-storage/atlas/bscsp*. Schaef, T., and McGrail, P. "Sequestration of CO_2 in Basalt Formations." Pacific Northwest National Laboratory, NETL, DOE, 2013. Available online at: *https://www.netl.doe.gov/sites/default/files/event-proceedings/2013/carbon%20storage/8-00-Schaef-58159-Task-1-082213.pdf*.

sequestration potential.[293] The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline. Overall, the EPA found that there are 43 states with access to or within 100 km from onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs.

As described in the 2015 NSPS, electricity demand in states that may not have geologic sequestration sites may be served by new generation, including new base load combustion turbines, built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines.[294] This approach has long been used in the electricity sector because siting an EGU away from a load center and transmitting the generation long distances to the load area can be less expensive and easier to permit than siting the EGU near the load area.

In many of the areas without access to geologic sequestration, utilities, electric cooperatives, and municipalities have a history of joint ownership of electricity generation outside the region or contracting with electricity generation in outside areas to meet demand. Some of the areas are in RTOs,[295] which engage in planning as well as balancing supply and demand in real time throughout the RTO's territory. Accordingly, generating resources in one part of the RTO can serve load in other parts of the RTO, as well as load outside of the RTO. For example, the Prairie State Generating Plant, a 1,600-MW coal-fired EGU in Illinois that is currently considering retrofitting with CCS, serves load in eight different states from the midwest to the mid-Atlantic.[296] The Intermountain Power Project, a coal-fired plant located in Delta,

[293] *GHG Mitigation Measures – 111(d)* TSD, chapter 4.6.2.
[294] This was described as "coal-by-wire" in the 2015 NSPS.
[295] In this discussion, the term RTO indicates both ISOs and RTOs.
[296] *https://prairiestateenergycampus.com/about/ownership/.*

Utah, that is converting to burn hydrogen and natural gas, serves customers in both Utah and California.[297]

(B) Costs

The EPA has evaluated the costs of CCS for new combined cycle units, including the cost of installing and operating CO_2 capture equipment as well as the costs of transport and storage, and is proposing that these costs are reasonable. Certain elements of the transport and storage costs are similar for new combustion turbines and existing steam generating units. In this section, we outline these costs and identify the considerations specific to new combustion turbines. These costs are significantly reduced by the IRC section 45Q tax credit. For additional details on the EPA's CCS costing analysis see the TSD titled *GHG Mitigation Measures – 111(d)*, which is available in the rulemaking docket.

(1) Capture costs

According to the NETL Fossil Energy Baseline Report (October 2022 revision), before accounting for the IRC section 45Q tax credit for sequestered CO_2, using a 90 percent capture amine-based post-combustion CO_2 capture system increases the capital costs of a new combined cycle EGU by 115 percent on a $/kW basis, increases the heat rate by 13 percent, increases incremental operating costs by 35 percent, and derates the unit (*i.e.*, decreases the capacity available to generate useful output) by 11 percent.[298] For a base load combustion turbine, carbon capture increases the LCOE by 61 percent (an increase of 27 $/MWh) and has an estimated cost

[297] *https://www.ipautah.com/participants-services-area/.*
[298] CCS reduced the net output of the NETL F class combined cycle EGU from 726 MW to 645 MW.

of $81/ton ($89/tonne) of onsite CO_2 reduction.[299] The NETL costs are based on the use of a second generation amine-based capture system without exhaust gas recirculation (EGR) and does not take into account further cost reductions that can be expected to occur as post-combustion capture systems are more widely deployed.

The flue gas from NGCC EGUs differs from that of a coal-fired EGUs in several ways that impact the cost of CO_2 capture. These include that the CO_2 concentration is approximately one-third, the volumetric flow rate on a per MW basis is larger, and the oxygen concentration is approximately 3 times that of a coal-fired EGU. The higher amount of excess oxygen has the potential to reduce the efficiency of amine-based solvents that are susceptible to oxidation. Other important factors include that the lower concentrations of CO_2 reduce the efficiency of the capture process and that the larger volumetric flow rates require a larger CO_2 absorber, which increases the capital cost of the capture process. EGR, also referred to as flue gas recirculation (FGR), is a process that addresses all of these issues. EGR diverts some of the combustion turbine exhaust gas back into the inlet stream for the combustion turbine. Doing so increases the CO_2 concentration and decreases the O_2 concentration in the exhaust stream and decreases the flow rate, producing more favorable conditions for CCS. One study found that EGR can decrease the capital costs of a combined cycle EGU with CCS by 6.4 percent, decrease the heat rate by 2.5 percent, decrease the LCOE by 3.4 percent, and decrease the overall CO_2 capture costs by 11 percent relative to a combined cycle EGU without EGR.[300]

[299] These calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.69/MMBtu, and a capacity factor of 65 percent. These costs do not include CO_2 transport, storage, or monitoring costs.
[300] Energy Procedia. (2014). *Impact of exhaust gas recirculation on combustion turbines. Energy and economic analysis of the CO_2 capture from flue gas of combined cycle power plants*. Accessed at *https://www.sciencedirect.com/science/article/pii/S1876610214001234*.

Furthermore, the EPA expects that the costs of capture systems will also decrease over the rest of this decade and continue to decrease afterwards. As part of the plan to reduce the costs of CO_2 capture, the DOE is funding multiple projects to advance CCS technology.[301] These include projects falling under carbon capture research and development, engineering-scale testing of carbon capture technologies, and engineering design studies for carbon capture systems. The projects will aim to capture CO_2 from various point sources, including NGCC units, cement manufacturing plants, and iron and steel plants. The general aim is to reach 95 percent or greater capture of CO_2, to lower the costs of the technologies, and to prove feasible scalability at the industrial scale. Some projects are designed solely to develop new carbon capture technologies, while others are designed to apply existing technologies at the industrial

[301] The DOE has also previously funded FEED studies for NGCC facilities. These include FEED studies at existing NGCC facilities at Panda Energy Fund in Texas, Elk Hills Power Plant in Kern County, California, Deer Park Energy Center in Texas, Delta Energy Center in Pittsburg, California, and utilization of a Piperazine Advanced Stripper (PZAS) process for CO_2 capture conducted by The University of Texas at Austin.

scale. Some of the notable DOE-funded projects related to NGCC units are as follows:[302] [303] [304] [305] [306]

- General Electric (GE) (Bucks, Alabama) was awarded $5,771,670 to retrofit an NGCC facility with CCS technology to capture 95 percent of CO_2, and is targeting commercial deployment by 2030.
- Wood Environmental & Infrastructure Solutions (Blue Bell, Pennsylvania) was awarded $4,000,000 to complete an engineering design study for CO_2 capture at the Shell Chemicals Complex. The aim is to reduce CO_2 emissions by 95 percent using post-combustion technology to capture CO_2 from several plants, including an onsite natural gas CHP plant.
- General Electric Company, GE Research (Niskayuna, New York) was awarded $1,499,992 to develop a design to capture 95 percent of CO_2 from NGCC flue gas with the potential to reduce electricity costs by at least 15 percent.

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[302] General Electric (GE) (2022). *U.S. Department of Energy Awards $5.7 Million for GE-Led Carbon Capture Technology Integration Project Targeting to Achieve 95% Reduction of Carbon Emissions*. Press Release. February 15, 2022. Accessed at *https://www.ge.com/news/press-releases/us-department-of-energy-awards-57-million-for-ge-led-carbon-capture-technology*.
[303] Larson, A. (2022). *GE-Led Carbon Capture Project at Southern Company Site Gets DOE Funding*. Power. Accessed at *https://www.powermag.com/ge-led-carbon-capture-project-at-southern-company-site-gets-doe-funding/*.
[304] U.S. Department of Energy (DOE) (2021). *DOE Invests $45 Million to Decarbonize the Natural Gas Power and Industrial Sectors Using Carbon Capture and Storage*. October 6, 2021. Accessed at *https://www.energy.gov/articles/doe-invests-45-million-decarbonize-natural-gas-power-and-industrial-sectors-using-carbon*.
[305] DOE (2022). *Additional Selections for Funding Opportunity Announcement 2515*. Office of Fossil Energy and Carbon Management. Accessed at *https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515*.
[306] DOE (2019). *FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants.* Office of Fossil Energy and Carbon Management. Accessed at *https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas*.

- SRI International (Menlo Park, California) was awarded $1,499,759 to design, build, and test a technology that can capture at least 95 percent of CO_2 while demonstrating a 20 percent cost reduction compared to existing NGCC carbon capture.
- CORMETECH, Inc. (Charlotte, North Carolina) was awarded $2,500,000 to further develop, optimize, and test a new, lower cost technology to capture CO_2 from NGCC flue gas and improve scalability to large NGCC plants.
- TDA Research, Inc. (Wheat Ridge, Colorado) was awarded $2,500,000 to build and test a post-combustion capture process to improve the performance of NGCC flue gas CO_2 capture.
- GE Gas Power (Schenectady, New York) was awarded $5,771,670 to perform an engineering design study to incorporate a 95 percent CO_2 capture solution for an existing NGCC site while providing lower costs and scalability to other sites.
- Electric Power Research Institute (EPRI) (Palo Alto, California) was awarded $5,842,517 to complete a study to retrofit a 700-Mwe NGCC with a carbon capture system to capture 95 percent of CO_2.
- Gas Technology Institute (Des Plaines, Illinois) was awarded $1,000,000 to develop membrane technology capable of capturing more than 97 percent of NGCC CO_2 flue gas and demonstrate upwards of 40 percent reduction in costs.
- RTI International (Research Triangle Park, North Carolina) was awarded $1,000,000 to test a novel non-aqueous solvent technology aimed at demonstrating 97 percent capture efficiency from simulated NGCC flue gas.

- Tampa Electric Company (Tampa, Florida) was awarded $5,588,173 to conduct a study retrofitting Polk Power Station with post-combustion CO_2 capture technology aiming to achieve a 95 percent capture rate.

Although current post-combustion CO_2 capture projects have primarily been based on amine capture systems, there are multiple alternate capture technologies in development—many of which are funded through industry research programs—that could have reductions in capital, operating, and auxiliary power requirements and could reduce the cost of capture significantly or improve performance. More specifically, post combustion carbon capture systems generally fall into one of several categories: solvents, sorbents, membranes, cryogenic, and molten carbonate fuel cells[307] systems. It is expected that as CCS infrastructure increases, technologies from each of these categories will become more economically competitive. For example, advancements in solvents, that are potentially direct substitutes for current amine-solvents, will reduce auxiliary energy requirements and reduce both operating and capital costs, and thereby, increasing the economic competitiveness of CCS.[308] Planned large-scale projects, pilot plants, and research initiatives will also decrease the capital and operating costs of future CCS technologies.

In general, CCS costs have been declining as carbon capture technology advances.[309] While the cost of capture has been largely dependent on the concentration of CO_2 in the gas

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[307] Molten carbonate fuel cells are configured for emissions capture through a process where the flue gas from an EGU is routed through the molten carbonate fuel cell that concentrates the CO_2 as a side reaction during the electric generation process in the fuel cell. FuelCell Energy, Inc. (2018). *SureSource Capture*. *https://www.fuelcellenergy.com/recovery-2/suresource-capture/*.
[308] DOE. *Carbon Capture, Transport, & Storage*. *Supply Chain Deep Dive Assessment*. February 24, 2022. Accessed at *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf*.
[309] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions–A new era for CCUS*. Accessed at *https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus*.

stream, advancements in varying individual CCS technologies tend to drive down the cost of capture for other CCS technologies. The increase in CCS investment is already driving down the costs of near-future CCS technologies. For example, the capture costs at the Petra Nova CCS project[310] in Thompsons, Texas, were 35 percent lower than the capture costs at the Boundary Dam Power Station[311] in Saskatchewan, Canada, which was built only a few years earlier.[312] IEA suggests this trend will continue in the future as technology advancements "spill over" into other projects to reduce costs.[313]

(2) CO_2 Transport and Sequestration Costs

NETL's "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies" provides an estimation of transport costs based on the CO_2 Transport Cost Model.[314] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of

310 DOE (n.d.). *Petra Nova–W.A. Parish Project*. Accessed at *https://www.energy.gov/fecm/petra-nova-wa-parish-project*.
311 Massachusetts Institute of Technology (MIT) (2016). *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project*. Accessed at *https://sequestration.mit.edu/tools/projects/boundary_dam.html*.
312 International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions–CCUS technology innovation*. Accessed at *https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus*.
313 International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions–CCUS technology innovation*. Accessed at *https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus*.
314 Grant, T., *et al.* "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. 2019. Available online at: *https://www.netl.doe.gov/energy-analysis/details?id=3743*.

injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies that utilize the coal found in Illinois, East Texas, Williston, and Powder River basins.[315]

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have lower testing and monitoring costs.

NETL's Quality Guidelines model costs for a given cumulative storage potential. At a storage potential of 25 gigatons of CO_2, costs range between \$7.54/ton (\$8.32/metric ton) sequestered (in the Illinois Basin) to \$18.00/ton (\$19.84/metric ton) sequestered (in the Powder River Basin).[316]

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[315] National Energy Technology Laboratory (NETL), "FE/NETL CO2 Saline Storage Cost Model (2017)," U.S. Department of Energy, DOE/NETL-2018-1871, 30 September 2017. Available online at *https://netl.doe.gov/energy-analysis/details?id=2403*.
[316] Grant, T., *et al.* "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. 2019. Available online at: *https://www.netl.doe.gov/energy-analysis/details?id=3743*.

In addition, provisions in the BIL and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at a new combined cycle EGUs. The BIL establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[317] The IRA increases and extends the IRC section 45Q tax credit, as noted above.

(3) IRC Section 45Q Tax Credit

In determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at $85/tonne ($77/ton) and offsets a significant portion of the capture, transport, and sequestration costs, as noted above.

It is reasonable to take the tax credit into account because it reduces the cost of the controls to the source, which has a significant effect on the actual cost of installing and operating CCS. In addition, all sources that install CCS to meet the requirements of these proposals are eligible for the tax credit. The legislative history of the IRA makes clear that Congress was well aware that the EPA may promulgate rulemaking under CAA section 111 based on CCS and explicitly stated that the EPA should consider the tax credit to reduce the costs of CCUS (*i.e.*, CCS). Rep. Frank Pallone, the chair of the House Energy & Commerce Committee, included a statement in the Congressional Record when the House adopted the IRA in which he explained:

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[317] Department of Energy. "Biden-Harris Administration Announces $2 Billion from Bipartisan Infrastructure Law to Finance Carbon Dioxide Transportation Infrastructure." (2022). *https://www.energy.gov/articles/biden-harris-administration-announces-2-billion-bipartisan-infrastructure-law-finance#:~:text=Enacted%20under%20President%20Biden%27s%20Bipartisan,located%20in%20the%20United%20States.*

"The tax credit[] for CCUS … included in this Act may also figure into CAA Section 111 GHG regulations for new and existing industrial sources[.] ... Congress anticipates that EPA may consider CCUS … as [a] candidate[] for BSER for electric generating plants …. Further, Congress anticipates that EPA may consider the impact of the CCUS … tax credit[] in lowering the costs of [that] measure[]." 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone).

In the 2015 NSPS, in which the EPA determined partial CCS to be the BSER for GHGs from new coal-fired steam generating EGUs, the EPA recognized that the IRC section 45Q tax credit or other tax incentives factored into the cost of the controls to the sources. Specifically, the EPA calculated the cost of partial CCS on the basis of cost calculations from NETL, which included "a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer." 80 FR 64570 (October 23, 2015).

Similarly, in the 2015 NSPS, the EPA also recognized that revenues from utilizing captured CO_2 for EOR would reduce the cost of CCS to the sources, although the EPA did not account for potential EOR revenues for purposes of determining the BSER. *Id.* At 64563–64. In other rules, the EPA has considered revenues from sale of the by-products of emission controls to affect the costs of the emission controls. For example, in the 2016 Oil & Gas methane rule, the EPA determined that certain control requirements would reduce natural gas leaks and therefore result in the collection of recovered natural gas that could be sold; and the EPA further determined that revenues from the sale of the recovered natural gas reduces the cost of controls. See 81 FR 38824 (June 14, 2016). In a 2011 action concerning a regional haze SIP, the EPA recognized that a NO_X control would alter the chemical composition of fly ash that the source had previously sold, so that it could no longer be sold; and as a result, the EPA further determined that the cost of the NO_X control should include the foregone revenues from the fly ash sales. 76 FR 58570, 58603 (September 21, 2011).

The amount of the IRC section 45Q tax credit that the EPA is taking into account is $85/metric ton for CO_2 that is captured and stored. This amount is available to the affected source as long as it meets the prevailing wage and apprenticeship requirements of IRC section 45Q(h)(3)–(4). The legislative history to the IRA specifically stated that when the EPA considers CCS as the BSER for GHG emissions from industrial sources in CAA section 111 rulemaking, the EPA should determine the cost of CCS by assuming that the sources would meet those prevailing wage and apprenticeship requirements. 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone).

(4) Total Costs of CCS

In a typical NSPS analysis, the EPA amortizes costs over the expected life of the affected facility and assumes constant revenue and expenses over that period of time. This analysis is different because the IRC section 45Q tax credits for the sequestration of CO_2 are only available for combustion turbines that commence construction by the end 2032 and are available for 12 years. The construction timeframe is within the NSPS review cycle, and the EPA has determined that it is appropriate to include the credits as part of the CCS costing analysis. Since the duration of the tax credit is less than the expected life of a new base load combustion turbine, the EPA conducted the costing analysis assuming a 30-year useful life and a separate analysis assuming the capital costs are amortized over a 12-year period. For the 30-year analysis, the EPA used a discount rate of 3.8 percent for the 45Q tax credits to get an effective 30-year value of $41/ton.

Even considering that the IRC section 45Q tax credits are currently available for only 12 years and would, therefore, only offset costs for a portion of a new NGCC turbine's expected operating life, the current overall CO_2 abatement costs of CCS of a 90 percent capture amine-based post combustion capture system, accounting for the tax credit, are $44/ton ($49/tonne) and the increase in the LCOE is $15/MWh.[318] These costs assume a stable 30-year operating life and do not include any revenues from sale of the CO_2 following the 12-year period when the IRC section 45Q tax credit is available. An alternate costing approach is to assume all capital costs are amortized during the 12-year period when tax credits are available. These tax credits are a significant source of revenue and would lower the incremental generating costs of the unit. Therefore, under the 12-year costing approach the EPA increased the assumed annual capacity factor from 65 to 75 percent. The 12-year CO_2 abatement costs are $19/ton ($21/tonne) and the increase in the LCOE is $6/MWh. These costs are for a combined cycle unit with a base load rating of 4,600 MMBtu/h with an output of approximately 700 MW.[319] These costs could be higher for small units and lower for larger units. For additional details on the CCS costing analysis see the TSD titled *GHG Mitigation Measures – 111(b),* which is available in the rulemaking docket.

(5) Comparison to Costs of Controls on EGUs for Other Pollutants

In assessing cost reasonableness for the BSER determination for this rule, the EPA compares the costs of GHG control measures to costs that EGUs have incurred to install controls

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[318] The EPA used 3.76 percent discount factor to levelized the 45Q tax credits to an annual value of $45.4/tonne. These calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.69/MMBtu, a capacity factor of 65 percent, and a transport, storage, and monitoring cost of $10/tonne.

[319] The output of the model combined cycle EGU without CCS is 726 MW. The auxiliary load of CCS reduces the net out to 645 MW.

that reduce other air pollutants, such as SO_2. At different times, many coal-fired steam generating units have been required to install and operate flue gas desulfurization (FGD) equipment—that is, wet or dry scrubbers—to reduce their SO_2 emissions. These control costs are compared across technologies—steam generating units and combustion turbines—because these costs are indicative of what is reasonable for the power sector in general. The fact that many EGUs have installed and operated these controls is evidence that these costs are reasonable, and as a result, the cost of these controls provides a benchmark to assess the reasonableness of the costs in this preamble. In the 2011 Cross-State Air Pollution Rule (CSAPR) (76 FR 48208; August 8, 2011), the EPA estimated the annualized costs to install and operate wet FGD retrofits on coal-fired steam generating units. Using those same cost equations and assumptions (*i.e.*, a 63 percent annual capacity factor – the average value in 2011) for a representative 300 to 700 MW coal-fired steam generating unit results in annualized costs of $15.00 to $18.50/MWh of generation.[320] In comparison, the cost for CCS applied to a representative new base load stationary combustion turbine EGU are comparable, ranging from $6 to $15/MWh (depending on the amortization period). Therefore, the EPA is proposing that the costs for CCS for those units are reasonable.

(C) Non-air Quality Health and Environmental Impact and Energy Requirements

In this section of the preamble, the EPA evaluates the non-air quality health and environmental impact and energy requirements of CCS specific to combined cycle combustion turbines. In particular, the Agency has considered non-GHG emissions impacts and water use impacts, as well as energy requirements, resulting from the capture, transport and sequestration

[320] For additional details, see *https://www.epa.gov/power-sector-modeling/documentation-integrated-planning-model-ipm-base-case-v410*.

of CO_2. Use of CCS is not expected to have unreasonable adverse consequences related to non-air quality health and environmental impacts or energy requirements.[321]

Including a 90 percent or greater carbon capture system in the design of a new NGCC will increase the parasitic/auxiliary energy demand and reduce its net power output. A utility that wants to construct an NGCC unit to provide 500 MWe-net of power could build a 500 MWe-net plant knowing that it will be essentially de-rated by 11 percent (to a 444 MWe-net plant) with the installation and operation of CCS. In the alternative, the project developer could build a larger 563 MWe-net NGCC plant knowing that, with the installation of the carbon capture system, the unit will still be able to provide 500 MWe-net of power to the grid. The 563 MWe plant will, as a consequence of its larger size, have the potential to emit more air pollutants than the smaller 500 MWe plant. However, in either scenario, the installation of CCS does not impact the unit's potential-to-emit any of the criteria or hazardous air pollutants. In other words, a new base load stationary combustion turbine EGU constructed using highly efficient generation (the first component of the BSER) would not see an increase in emissions of criteria or hazardous air pollutants as a consequence of installing and using 90 or greater percent CO_2 capture CCS to meet the second phase standard of performance.[322]

Due to their relatively high efficiency, combined cycle EGUs have relatively small cooling requirements compared to other base load EGUs. According to NETL, a combined cycle EGU without CCS requires 190 gallons of cooling water per MWh of electricity. CCS increases

[321] In outreach with potentially vulnerable communities, residents have voiced two primary concerns. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS and hydrogen, they may continue to face disproportionate burden. This is discussed further in section XIV.E. of this preamble.

[322] While the absolute onsite mass emissions would not increase from the second component of the BSER, the emissions rate on a lb/MWh-net basis would increase by 13 percent.

the cooling water requirements due both to the decreased efficiency and the cooling requirements for the CCS process to 290 gallons per MWh, an increase of about 50 percent. However, because NGCC units require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS does not present unsurmountable concerns. In addition, many combined cycle EGUs currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water. Therefore, the EPA is proposing that the additional cooling water requirements from CCS are reasonable.

As noted in section VII.F.3 of this preamble, PHMSA oversight of CO_2 pipeline safety protects against environmental release during transport and UIC Class VI regulations under the SDWA in tandem with GHGRP requirements ensure the protection of USDWs and the security of geologic sequestration.

(D) Impacts on the Energy Sector

The EPA expects that several new NGCC units will install CCS because, as discussed earlier in section VII.F.3.iii.(A) of this preamble, a few have already announced that they will. However, the Agency does not expect a large number of new NGCC units to install CCS. This is because as more renewable generation and energy storage are built, the need for base load generating capacity is likely to fall. This reduction in utilization of combined cycle combustion turbine capacity can be seen in the EPA's reference case modeling (post-IRA 2022 reference case, see section IV.F of the preamble). Further, a number of companies have recently announced plans to move away from new NGCC projects in favor of more renewables, battery storage, and low load combustion turbines. For example, Xcel took this approach with regards to a proposed combined cycle plant to replace the retiring Sherco coal-fired plant.[323]

(E) Extent of Reductions in CO_2 Emissions

Designating CCS as a component of the BSER for certain base load combustion turbine EGUs prevents large amounts of CO_2 emissions. For example, a new base load combined cycle EGU without CCS could be expected to emit 45 million tons of CO_2 over its operating life. Use of CCS would avoid the release of nearly 41 million tons of CO_2 over the operating life of the combined cycle EGU. However, due to the auxiliary/parasitic energy requirements of the carbon capture system, capturing 90 percent of the CO_2 does not result in a corresponding 90 percent reduction in CO_2 emissions. According to the NETL baseline report, adding a 90 percent CO_2 capture system increases the EGU's gross heat rate by 7 percent and the unit's net heat rate by 13 percent. Since more fuel would be consumed in the CCS case, the gross and net emissions rates are reduced by 89.3 percent and 88.7 percent respectively.

(F) Promotion of the Development and Implementation of Technology

The EPA also considered whether determining CCS to be a component of the BSER for long term coal-fired steam generating units and for new base load combustion turbines will advance the technological development of CCS, and concluded that this factor supports our BSER determination. An emission standard based on highly efficient generation in combination with the use of CCS—combined with the availability of 45Q tax credits—should incentivize additional use of CCS which should incentivize cost reductions through the development and use of better performing solvents or sorbents. While solvent-based CO_2 capture has been adequately

[323] *https://cubminnesota.org/xcel-is-no-longer-pursuing-gas-power-plant-proposes-more-renewable-power/.*

demonstrated at the commercial scale, a determination that a component of the BSER for new base load stationary combustion turbine (and long term coal-fired steam generating units) is the use of CCS will also likely incentivize the deployment of alternative CO_2 capture techniques at scale. Moreover, as noted above, the cost of CCS has fallen in recent years and is expected to continue to fall; and further implementation of the technology can be expected to lead to additional cost reductions, due to added experience and cost efficiencies through scaling.

The experience gained by utilizing CCS with stationary combustion turbine EGUs, with their lower CO_2 flue gas concentration relative to other industrial sources such as coal-fired EGUs, will advance capture technology with other lower CO_2 concentration sources. The EIA 2022 Annual Energy Outlook projects that almost 1,400 billion kWh of electricity will be generated from natural gas-fired sources in 2040.[324] Much of that generation is projected to come from existing combined cycle EGUs and further development of carbon capture technologies could facilitate increased retrofitting of those EGUs.

(G) Proposed BSER

The Agency proposes that for new natural gas-fired base load combustion turbines, an efficient stationary combustion combined cycle turbine utilizing CCS at a capture rate of 90 percent, beginning in 2035, qualifies as the BSER because it is adequately demonstrated; it is of reasonable cost taking account of the IRC section 45Q tax credit, it achieves significant emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements, including on a nationwide basis. The fact

[324] AEO 2022 does not include the impact of recent changes to the tax code. These changes will likely result in a reduction in the projection of generation from combustion turbines.

that it promotes useful technology provides additional, although not essential, support for this proposal.

iv. Low-GHG hydrogen

As discussed later in section VII.F.3.c, the EPA is also proposing that beginning in 2035, the second component of BSER for base load combustion turbines combusting at least 10 percent (by heat input) hydrogen is co-firing 30 percent low-GHG hydrogen. However, co-firing low-GHG hydrogen does not qualify as the BSER for base load combustion turbines not combusting at least 10 percent (by heat input) hydrogen because it achieves lower GHG reductions than through the use of CCS.

v. Why the EPA is Proposing a Second Component of BSER, Based on CCS, in 2035

When considering whether a technology should be BSER, the EPA must consider both unit level and nationwide questions. At the unit level, the EPA must ask whether the technology is proven, can be implemented at reasonable cost, and achieves emission reductions without causing other significant environmental or energy issues. With regards to CCS at the unit level, the EPA believes there is ample evidence to conclude that it is available and cost reasonable (with the 45Q tax credits) today. When looking at the technology from a nationwide basis, the EPA must take larger system-wide impacts into consideration. For CCS this includes questions about infrastructure for transportation and storage,[325] as well as considerations relating to the lead time needed to scale-up manufacturing and installation of carbon capture equipment to meet the amount of capacity potentially subject to this proposed BSER (in addition to meeting IRA-driven demand for CCS in other sectors).

[325] For further information on timing associated with CO_2 transport and storage design, engineering, and construction, see *GHG Mitigation Measures – 111(d)* TSD, chapter 4.7.1.

When considering these larger geographic questions, the EPA is also mindful of requirements on other sources within the larger EGU category. As discussed later in this preamble, the EPA is also proposing a determination that the BSER for existing coal-fired EGUs with long operating horizons is CCS, with a requirement that sources meet the associated standard of performance by January 1, 2030. The EPA believes that, if there are limited resources available to install CCS, priority should go to installation on existing coal-fired steam generating units which emit significantly more CO_2 than new baseload stationary combustion turbines (well over twice as much CO_2 on a lb per MWh basis).

The EPA's modeling projects that 12 GW of existing coal-fired steam generating units will install retrofit CCS and that more than 30 GW of new NGCC EGUs will be built by 2030. If all those new NGCC units were required to install CCS at the time of construction, that would result in the construction of more than 40 GW of CCS by 2030. This does not include construction of CCS systems that are likely to be installed in other industries incentivized by the IRA. The EPA believes there are multiple reasons to delay the second phase of the standard of performance that is based on application of highly efficient generation and use of CCS until 2035. First, new combined cycle combustion turbines have inherently lower uncontrolled GHG emission rates than many of the other types of units that are likely to install CCS in the 2030 – 2035 timeframe. The EPA also recognizes that a number of companies are planning to build NGCC units to replace retiring coal-fired units. If there are supply chain delays or other delays such as shortages in engineering services, specialty labor, *etc*. critical to installing CCS, providing lower emitting NGCCs flexibility to delay installation allows higher emitting coal-fired units with plans to permanently cease operations to do so on the schedules chosen by owners and operators. Second, the EPA does not believe that all of the combustion turbine units that are likely to install CCS will choose to delay the installation. As discussed above, there are some technologies (*e.g.*, the NET Power Cycle) that are fully integrated into the combined cycle unit such that, if a company wishes to use this technology, it will be easier to install and integrate the CCS system when the unit is first constructed. Third, the EPA is aware that many companies are considering building combined cycle units to meet near term demand as coal-fired steam generating units cease operations and are planning to eventually convert the combined cycle units to hydrogen-fired (or co-fired) units that will operate more in an intermediate load fashion as more renewables and energy storage options are built and as a low-GHG hydrogen network is developed. Providing these units a delayed date to meet a second phase standard of performance that is based, in part, on the implementation of CCS will allow them to make more informed long term decisions. The EPA is proposing CCS as adequately demonstrated and cost reasonable for base load combustion turbines, and delaying deployment of CCS for the affected combustion turbines will provide the additional benefit of greater operational experience and potentially lower costs to install CCS or take advantage of a more fully developed low-GHG hydrogen infrastructure. By 2030 project developers are likely to have a much better picture with regards to the cost and performance of small modular nuclear reactors, advanced battery technology, and advances in renewables and distributed generation that are likely to make the long term path for combined cycle units much clearer. Companies will have a better understanding of the expected longer term operation of the combined cycle unit and whether it will continue to operate as a base load combustion turbine with CCS or with low-GHG hydrogen co-firing or whether it will operate as an intermediate load combustion turbine.

The EPA considered establishing the start of phase 2 of the standard of performance as early as 2030 on the assumption that projects that commence construction in the period immediately following this rulemaking will need at least that amount of time to implement the BSER. However, the EPA is also proposing to determine that the BSER for long-term coal-fired steam generating units (those that will be in operation beyond 2040) is the use of 90 percent capture CCS and that the associated standard of performance for those units is effective beginning in 2030. The EPA is also aware that a significant number of new base load combined cycle stationary combustion turbines are projected to be constructed by 2030, and that there are other, non-power sector industries that will also be pursuing implement of CCS in that timeframe. The EPA believes that the deployment of CCS infrastructure, including the demand for the manufacturing and installation of CCS equipment and the demand for constructing the CO_2 pipeline infrastructure and to conducting sequestration site characterization and permitting, should be prioritized for the higher GHG emitting fleet of existing long-term coal-fired steam generating units. The EPA also understands that many utilities and power generating companies are trying to assess their near term and long term base load generating needs and may have useful information to provide to the record that would help to assess the demand for CCS. So, considering all those factors, the EPA is proposing that phase 2 of the standard of performance begin in 2035 to ensure achievability of the standard. The EPA also recognizes that commenters may have more information about implementing CCS on a broader scale that would help to assess whether 2030 or 2035 (or somewhere in between) would be an appropriate start date for phase 2 of the standards of performance that are based, in part, on the use of CCS. For this reason, the EPA solicits comment on whether the compliance date for phase 2 of the standards of performance should begin earlier than 2035, including as early as 2030.

c. BSER for Base Load Subcategory Combusting At Least 10 percent Hydrogen and for Intermediate Load Subcategories – Second Component

This section describes the second component of the EPA's proposed BSER for the subcategory of base load combustion turbines that co-fire at least 10 percent (by heat input) hydrogen and for combustion turbines in the intermediate load subcategory. For both subcategories, the EPA is proposing that the second component of the BSER is co-firing 30 percent by volume low-GHG hydrogen, beginning in 2035. The first part of this section is a background discussion concerning several key aspects of the hydrogen industry as it is currently developing. At the outset, the EPA summarizes the activities of some power producers and turbine manufacturers to develop and demonstrate hydrogen co-firing as a viable decarbonization technology for the power sector. The EPA then discuss the GHG emissions performance of stationary combustion turbines when hydrogen is used as a fuel. This discussion includes the different methods of production and the associated GHG emissions for each. The second part of this section describes the proposed second component of the BSER, which is co-firing 30 percent by volume low-GHG hydrogen. The EPA is also proposing a definition of low-GHG hydrogen. The EPA is proposing that hydrogen qualifies as low-GHG hydrogen if it is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H_2, on a well-to-gate basis). Hydrogen produced by electrolysis (splitting water into hydrogen and oxygen) using electricity produced through low-GHG energy—may be a type of hydrogen that could qualify as low-GHG hydrogen for the purposes of this proposed BSER. However, the EPA is also soliciting comment on whether a specific definition of low-GHG hydrogen should even be included in the final rule. The third part of this section explains why the EPA proposes that co-firing 30 percent by volume low-GHG hydrogen qualifies as a component of the BSER. Co-firing 30 percent hydrogen is technically feasible and well-demonstrated in new combustion turbines; it will be supported by an adequate supply by 2035; it will be of reasonable cost; it will ensure reductions of GHG emissions; and, it will be consistent with the other BSER factors. The EPA also includes in this section an explanation of why the Agency thinks that highly efficient generating technology combined with co-firing low-GHG hydrogen (as opposed to any hydrogen) is the "best" system of emission reduction taking into account the statutory considerations.

i. Clean Fuels

The EPA is not proposing clean fuels as the second component of BSER for intermediate load or base load turbines combusting 10 percent or more hydrogen because it would achieve few emission reductions, compared to co-firing low-GHG hydrogen.

ii. Highly Efficient Generation

For the reasons described above, the EPA is proposing that highly efficient generation technology in combination with best operating and maintenance practices continues to be a component of the BSER that is reflected in the second phase of the standards of performance for base load turbines combusting 10 percent or more hydrogen and intermediate load combustion turbines. Highly efficient generation reduces fuel use and the absolute amount, and cost, of low-GHG hydrogen that would be required to comply with the second phase standards.

iii. CCS

The EPA is not proposing the use of CCS as a component of the BSER for the intermediate load subcategory or the base load subcategory for combustion turbines combusting 10 percent or more hydrogen. As described previously, simple cycle technology is the likely combustion turbine technology applicable to the intermediate load subcategory and the Agency is limiting consideration of CCS to combined cycle EGUs. Intermediate load combustion turbines tend to start and stop frequently and have relatively short periods of continuous operation. CCS systems could have difficulty starting sufficiently quickly to get significant levels of CO_2 capture. In addition, the CCS equipment could essentially remain idle for much of the time while these units are not running. For these reasons, CCS would be significantly less cost-effective for intermediate load combustion turbine EGUs as compared to base load units.

iv. Background Discussion of Hydrogen and the Electric Power Sector, Hydrogen Co-firing in Combustion Turbines, and Hydrogen Production Processes

Hydrogen in the United States is primarily used for refining petroleum and producing fertilizer, with smaller amounts also used in sectors like metals treatment, processing foods, and production of specialty chemicals.[326] In recent years, applications of hydrogen have expanded to include co-firing in combustion turbines used to generate electricity. In fact, many models of existing combustion turbines that are used for electricity generation have successfully demonstrated the ability to co-fire blends of 5 to 10 percent hydrogen by volume without modification to the combustion system. Furthermore, combustion of hydrogen blends as high as 20 to 30 percent by volume are being tested and demonstrated; and new turbine designs that can accommodate co-firing 30 to 50 percent hydrogen by volume are being developed.

Several power producers made financial investments and began work on hydrogen co-firing projects prior to passage of the IRA in August 2022. For example, in early 2021, the Intermountain Power Agency (IPA) project in Utah began the transition away from an operating 1,800-MW coal-fired steam generating unit to an 840-MW combined cycle combustion turbine

[326] *https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php.*

that will integrate 30 percent hydrogen by volume co-firing at start-up in 2025.[327] IPA and its partners have announced plans to produce low-GHG hydrogen via solar-powered electrolysis with storage in underground geologic formations on route to combusting 100 percent low-GHG hydrogen in the combined cycle unit by 2045. IPA also has agreements to sell its electricity to the Los Angeles Department of Water and Power.

Another example is the Long Ridge Energy Generation Project in Ohio.[328] The 485-MW combined cycle combustion turbine became operational in 2021 and successfully co-fired 5 percent hydrogen by volume in March 2022.[329] [330] The planned next step for Long Ridge is to co-fire 20 percent hydrogen by volume with the existing turbine design, which has been commercially available since 2017 and can co-fire 15 to 20 percent hydrogen by volume without modification.[331] Furthermore, in June 2022, Southern Company successfully demonstrated the co-firing of a 20 percent hydrogen blend at Georgia Power's Plant McDonough-Atkinson. The co-firing demonstration was performed on a combustion turbine at partial and full loads and

[327] Intermountain Power Agency (2022). See *https://www.ipautah.com/ipp-renewed/*.
[328] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence*. See *https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio*.
[329] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal*. See *https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/*.
[330] Defrank, Robert (2022). *Cleaner Future in Sight: Long Ridge Energy Terminal in Monroe County Begins Blending Hydrogen*. See *https://www.theintelligencer.net/news/community/2022/04/cleaner-future-in-sight-long-ridge-energy-terminal-in-monroe-county-begins-blending-hydrogen/#:~:text=DeFrank%20%2D%20The%20Long%20Ridge%20Energy,its%20kind%20in%20the%20country*.
[331] Patel, S. (April 22, 2022). First Hydrogen Burn at Long Ridge HA-Class Gas Turbine Marks Triumph for GE. Power. See *https://www.powermag.com/nypa-ge-successfully-pilot-hydrogen-retrofit-at-aeroderivative-gas-turbine/*.

produced a 7 percent reduction in CO_2 emissions.[332] In September 2022, the New York Power Authority (NYPA) successfully co-fired a 44 percent blend of hydrogen by volume in a retrofitted combustion turbine. According to the Electric Power Research Institute (EPRI), the project demonstrated a 14 percent reduction in CO_2 at a 35 percent by volume hydrogen blend. The unit's existing SCR controlled NO_X emissions within permit limits.[333] [334] [335]

Other power producers have implemented large low-GHG hydrogen plans that integrate multiple elements of their generating assets. In Florida, NextEra announced in June 2022 a comprehensive carbon emission reduction plan that will eventually convert 16 GW of natural gas-fired generation to operate on low-GHG hydrogen as part of the utility's 2045 GHG reduction goal.[336] Also, NextEra's Cavendish NextGen Hydrogen Hub will produce hydrogen with a 25-MW electrolyzer system powered by solar energy and the hydrogen will then be co-fired by combustion turbines at Florida Power and Light's 1.75-GW Okeechobee power plant.[337]

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[332] Patel, S. (2022). *Southern Co. Gas-Fired Demonstration Validates 20% Hydrogen Fuel Blend.* See *https://www.powermag.com/southern-co-gas-fired-demonstration-validates-20-hydrogen-fuel-blend/*.
[333] Palmer, W., & Nelson, B. (2021). *An H_2 Future: GE and New York power authority advancing green hydrogen initiative*. See *https://www.ge.com/news/reports/an-h2-future-ge-and-new-york-power-authority-advancing-green-hydrogen-initiative*.
[334] Van Voorhis, S. (2021). New York to test green hydrogen at Long Island power plant. *Utility Dive*. See *https://www.utilitydive.com/news/new-york-to-test-green-hydrogen-at-long-island-power-plant/603130/*.
[335] Electric Power Research Institute (EPRI). (2022, September 15). *Hydrogen Co-Firing Demonstration at New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine*. Low Carbon Resources Initiative. See *https://www.epri.com/research/products/000000003002025166*.
[336] NextEra Energy (2022). Zero Carbon Blueprint. See *https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf*.
[337] Clean Energy Group. *Hydrogen Projects in the U.S*. See *https://www.cleanegroup.org/ceg-projects/hydrogen/projects-in-the-us/*.

One of the first power producers to invest in hydrogen as a fuel for combustion turbines was Entergy, which reached an agreement with turbine manufacturer Mitsubishi Power in 2020 to develop hydrogen-capable combined cycle facilities that include low-GHG hydrogen production, storage, and transportation components.[338] In October 2022, Entergy and New Fortress Energy announced plans to collaborate on a renewable energy and 120-MW hydrogen production plant in southeast Texas.[339] The partnership includes electricity transmission infrastructure as well as the development of renewable energy resources and the offtake of low-GHG hydrogen. A feature of the agreement is Entergy's Orange County Advanced Power Station, which received approval from the Public Utility Commission of Texas in November 2022.[340] The 1,115-MW power plant will replace end-of-life gas generation with new combined cycle combustion turbines that are ready to co-fire hydrogen. Construction will begin in 2023 and the project will be completed in 2026.

Hydrogen offers unique solutions for decarbonization because of its potential to provide dispatchable, clean energy with long-term storage and seasonal capabilities. For example, hydrogen is an energy carrier that can provide long-term storage of low-GHG energy that can be co-fired in combustion turbines and used to balance load with the increasing volumes of variable These services can enhance the reliability of the power system while facilitating the integration of variable renewable energy resources and supporting decarbonization of the electric grid.

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[338] Mitsubishi Power Americas. (September 23, 2020). *Mitsubishi Power and Entergy to Collaborate and Help Decarbonize Utilities in Four States*. See *https://power.mhi.com/regions/amer/news/20200923.html*.
[339] Entergy. (October 19, 2022). Entergy Texas and New Fortress Energy partner to advance hydrogen economy in Southeast Texas. See *https://www.entergynewsroom.com/news/entergy-texas-new-fortress-energy-partner-advance-hydrogen-economy-in-southeast-texas/*.
[340] Entergy. (November 28, 2022). Entergy Texas receives approval to build a cleaner, more reliable power station in Southeast Texas. See *https://www.entergynewsroom.com/news/entergy-texas-receives-approval-build-cleaner-more-reliable-power-station-in-southeast-texas/*.

Related, hgeneration.[342]ydrogen has the potential to mitigate curtailment, which is the deliberate reduction of electric output below what could have been produced. Curtailment often occurs when regional transmission operators need to balance the grid's energy supply to meet demand. For example, in 2020, the California Independent System Operator (CAISO) curtailed an estimated 1.5 million MWh of solar generation. [343] Curtailment will likely increase as the capacity of variable generation continues to expand. One technology with the potential to reduce curtailment is energy storage, and some power producers envision a role for hydrogen to supplement natural gas as a fuel supporting balancing energy and ensuring reliability of an increasingly decarbonized electric grid.

Rapid progress is being made, and, due to the demonstrated ability of new and existing combustion turbines to co-fire hydrogen other utility owners/operators have publicly made long-term commitments to hydrogen co-firing and have identified the technology as a key component of their future operations and GHG reduction strategies. As highlighted by the earlier examples, the outlook expressed by multiple power producers and developers includes a future generation asset mix that retains combustion turbines fired exclusively with hydrogen. Utilities in vertically integrated states and merchant generators in wholesale markets rely on combustion turbines to provide reliable, dispatchable power.

v. Hydrogen Production Processes and Associated Levels of GHG Emissions

Hydrogen is used in industrial processes, and, as discussed previously, in recent years, applications of hydrogen co-firing have expanded to include stationary combustion turbines used

[342] For example, when the sun is not shining and/or the wind is not blowing.
[343] Walton, R. (August 25, 2021). CAISO forced to curtail 15% of California utility-scale solar in March, 5% last year. Power Engineering. See *https://www.power-eng.com/solar/caiso-forced-to-curtail-15-of-california-utility-scale-solar-in-march-5-last-year/#gref*.

to generate electricity. However, at present, nearly all industrial hydrogen is produced via methods that are GHG-intensive. To fully evaluate the potential GHG emission reductions from co-firing low-GHG hydrogen in a combustion turbine EGU, it is important to consider the different processes of producing the hydrogen and the GHG emissions associated with each process. The following discussion highlights the primary methods of hydrogen production as well as the sources of energy used during production and the level of GHG emissions that result from each production method. The varying levels of CO_2 emissions associated with hydrogen production are well-recognized, and stakeholders routinely refer to hydrogen on the basis of the different production processes and their different GHG intensities.[344]

More than 95 percent of the dedicated hydrogen currently produced in the U.S. originates from natural gas using steam methane reforming (SMR). This method produces hydrogen by adding steam and heat to natural gas in the presence of a catalyst. Methane reacts with the steam to produce hydrogen, carbon monoxide (CO), and trace amounts of CO_2. Further, the CO byproduct is routed to a second process, known as a water-gas shift reaction, to react with more steam to create additional hydrogen and CO_2. After these processes, the CO_2 is removed from the gas stream, leaving almost pure hydrogen.[345] CO_2 emissions are generated from the conversion process itself and from the creation of the thermal energy and steam (assuming the boilers are fueled by natural gas) or external energy sources powering the production process. Because the

[344] Some organizations have developed a convention for labeling each hydrogen production method, based on the GHG emissions associated with each method, according to a color scheme. The color labels are insufficiently specific for the purposes of this proposed rule, so the EPA generally does not refer to hydrogen using this color convention.
[345] U.S. Department of Energy (DOE) (n.d.). Hydrogen Production: Natural Gas Reforming. Accessed at *https://www.energy.gov/eere/fuelells/hydrogen-production-natural-gas-reforming*. For each kg of hydrogen produced through SMR, 4.5 kg of water is consumed.

thermal efficiency of SMR of natural gas is generally 80 percent or less,[346] less overall energy is in the produced hydrogen than in the natural gas required to produce the hydrogen. Therefore, the use of hydrogen produced through SMR in a combustion turbine would consume more natural gas than would have been consumed if the combustion turbine had burned the natural gas directly. Therefore, co-firing hydrogen derived from SMR based on fossil fuels without CCS results in higher overall CO_2 emissions than using the natural gas directly in the EGU.

The GHG emissions from hydrogen production via SMR can be controlled with CCS technology at different points in the production process. There are varying levels of CO_2 capture for different techniques, but typically a range of 65 to 90 percent is viable.[347] The autothermal reforming (ATR) of methane is a similar technology to SMR, but ATR utilizes natural gas in the process itself without an external heat source.[348] CCS can also be applied to ATR.

Another process to produce hydrogen is methane pyrolysis. Methane pyrolysis is the thermal decomposition of methane in the absence (or near absence) of oxygen, which produces hydrogen and solid carbon (*i.e.*, carbon black) as the only byproducts. Pyrolysis uses energy to power its hydrogen production process, and therefore the level of its overall GHG emissions depends on the carbon intensity of its energy inputs. For SMR, ATR, and pyrolysis technologies, emissions from methane extraction, production, and transportation are also significant aspects of their GHG emissions footprints.

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[346] Thermal efficiency is the amount of energy in the production (*e.g.*, hydrogen) compared to the energy input to the process (*e.g.*, natural gas). At an efficiency of 80 percent, the product contains 80 percent of the energy input and 20 percent is lost.
[347] Powell, D. (2020). *Focus on Blue Hydrogen*. Gaffney Cline. Accessed at *https://www.gaffneycline.com/sites/g/files/cozyhq681/files/2021-08/Focus_on_Blue_Hydrogen_Aug2020.pdf*.
[348] "Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas production regions," *Energy Conversion and Management*, February 15, 2022.

In contrast to the three methods discussed above, electrolysis does not use methane as a feedstock. In electrolysis, hydrogen is produced by splitting water into its components, hydrogen and O_2, via electricity. During electrolysis, a negatively charged cathode and positively charged anode are submerged in water and an electric current is passed through the water. The result is hydrogen molecules appearing at the negative cathodes and O_2 appearing at the positive anodes. Electrolysis does not have GHG emissions at the hydrogen production site; the overall GHG emissions associated with electrolysis are instead dependent upon the source of the energy used to decompose the water.[349] According to the DOE, electrolysis powered by fossil fuels, or by energy supplied by the electric grid, would generate overall GHG emissions double those of hydrogen produced via SMR.[350] However, electrolysis not connected to the grid and powered by wind, solar, hydroelectric, or nuclear energy are generally considered to lower overall GHG emissions, although system-wide emissions can still increase if the supply of low-carbon generation is constrained.[351] [352] Naturally occurring hydrogen stored in subsurface geologic formations is also gaining some attention as a potential source hydrogen.

[349] Similarly, the overall GHG emissions associated with methane pyrolysis are dependent upon the source of the energy used to decompose the methane and is a key factor to whether it qualifies as low-GHG hydrogen.
[350] DOE (2022). *DOE National Clean Hydrogen Strategy and Roadmap*. Draft—September 2022. Accessed at *https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf*.
[351] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production: Electrolysis*. Accessed at *https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis#:~:text=Electrolysis%20is%20a%20promising%20option,a%20unit%20called%20an%20electrolyzer*.
[352] For each kg of hydrogen produced through electrolysis, 9 kg of byproduct oxygen are also produced and 9 kg of purified water are consumed. To reduce the cost of hydrogen production, this byproduct oxygen could be captured and sold. For each gallon of water consumed, 0.057 MMBtu of hydrogen is produced. According to the water use requirements for combined cycle EGUs with cooling towers, if this hydrogen is later used to produce electricity in a combined cycle EGU overall water requirements would be greater than a combined cycle EGU with CCUS.

vi. The EPA's Proposed BSER and Definition of Low-GHG Hydrogen

The EPA is proposing that the second component of the BSER for new combustion turbines in the relevant subcategories is co-firing 30 percent by volume low-GHG hydrogen by 2035. This section describes the factors the EPA considered in determining what level of co-firing qualifies as a component of the BSER for affected sources and the timing for when that level of co-firing could be technically feasible and of reasonable cost. Key factors informing this determination include the magnitude of CO_2 stack emission reductions, the availability of combustion turbines capable of co-firing hydrogen, potential infrastructure limitations, and access to low-GHG hydrogen.

The relationship between the volume of hydrogen fired and the reduction in CO_2 stack emissions is exponential. At low levels of co-firing there are modest emission reduction benefits, but these reduction benefits amplify as the volume of hydrogen increases due to the lower energy density of hydrogen compared to natural gas. For example, co-firing 10 percent hydrogen by volume yields approximately a 3 percent CO_2 reduction at the stack, co-firing 30 percent yields a 12 percent reduction, co-firing 75 percent yields a 49 percent reduction, and at 100 percent hydrogen co-firing there are zero CO_2 emissions at the stack.

Importantly, co-firing 30 percent hydrogen by volume is consistent with existing technologies across multiple combustion turbine designs and should be considered a minimal level for evaluation as a system of emission reduction. While all major manufacturers are developing combustors that can co-fire higher volumes of hydrogen, some combustion turbine models are already able to co-fire relatively high percentages.[353] Several currently available new

[353] Mitsubishi Power Americas. See *https://power.mhi.com/special/hydrogen/article_1*.

combustion turbine models can burn up to 75 percent hydrogen by volume.[354] Combustion turbine designs capable of co-firing 30 percent hydrogen by volume are available from multiple manufacturers at multiple sizes. As such, a BSER that included co-firing 30 percent hydrogen would not pose challenges for near-term implementation for the EPA's proposed second phase standards beginning in 2035. The EPA is soliciting comment on whether the new and reconstructed combustion turbines will have available combustion turbine designs that would allow higher levels of hydrogen co-firing, such as 50 percent by volume by 2030 or 2035. If such combustion turbines are widely available, this would support moving forward the starting compliance date of the second phase of the standards of performance and/or increasing the percent of hydrogen co-firing assumed in establishing the standards.

Access to low-GHG hydrogen, however, is also an important component of the BSER analysis. Midstream infrastructure limitations and the adequacy and availably of hydrogen storage facilities currently present obstacles and increase prices for delivered low-GHG hydrogen. This is part of the rationale for why the EPA is not proposing hydrogen co-firing as part of the first component of the BSER. Moving gas via pipeline tends to be the least expensive transport and today there are 1,600 miles of dedicated hydrogen pipeline infrastructure. As noted later in a section of this preamble, based on industry announcements, many electrolytic hydrogen production projects will be sited near existing infrastructure and, in certain cases, will provide combustion turbines access to supply and delivery solutions. Hydrogen blending into existing natural gas pipelines presents another mode of transport and distribution that is actively under exploration. On-road distribution methods include gas-phase trucking and liquid hydrogen

[354] Overcoming technical challenges of hydrogen power plants for the energy transition (*https://www.nsenergybusiness.com*).

trucking, the latter requiring cooling and compression prior to transport. Different regional distribution solutions may emerge initially in response to localized hydrogen demand.

Gaseous and liquified hydrogen storage technologies are developing, along with lined hard rock storage and limited but promising geologic salt cavern storage. Increased storage capacity and market demand for low-GHG hydrogen is anticipated in response to federal H2Hub investments as low-GHG hydrogen develops from a localized fuel into a national commodity.

Given the growth in the hydrogen sector and Federal funding for the H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA therefore believes hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire 30 percent hydrogen by volume in 2035. The EPA is soliciting comment on whether hydrogen infrastructure will likely be sufficiently developed by 2030 to provide access to low-GHG hydrogen for new and reconstructed combustion turbines. If so, this would support moving forward the compliance date of the second phase of the standards of performance and/or increase the percent of hydrogen co-firing assumed in establishing the standards.

Whether there will be sufficient volumes of low-GHG hydrogen between 2030 to 2035will2035 will depend on the deployment of additional low-GHG electric generation sources, the growth of electrolyzer capacity, and market demand. Along with the power sector, the industrial and transportation sectors are also advancing hydrogen-ready technologies. Industries and policymakers in those sectors are actively planning to use hydrogen to drive decarbonization. For the industrial sector where hydrogen is a chemical input to the process or a replacement for liquid fuels, multiple projection pathways are being considered as approaches to lower the GHG intensity of these sectors. The production pathways for the industrial sector include, but are not limited to, fossil-derived hydrogen in combination with CCS. However, due to thermodynamic inefficiencies in using fossil-derived hydrogen to produce electricity, it is likely that only a specific type of low-GHG hydrogen will be used in the power sector. Announcements of co-firing applications support this assertion, and as discussed in another section of this preamble, the power sector is already focused on utilizing low-GHG hydrogen, electricity generators are likely to have ample access to low-GHG hydrogen and in sufficient quantities to support 30 percent co-firing by 2035. The DOE's estimates of clean hydrogen production volumes of 10 MMT by 2030 and 20 MMT by 2040, referenced throughout this rulemaking, do not apportion which type of hydrogen is likely to be produced[355] The EPA estimates power sector demand for hydrogen in response to this rulemaking to be in the range of 2.2 to 3.4 MMT by 2035. The available credit for the lowest hydrogen production tier under IRC section 45V tax subsidies going into effect in 2023, as outlined in another section of this preamble, are three times higher than the other credits alloted for other hydrogen production tiers in IRC section 45V, combined with additional monetization access through direct pay and transferability, and are therefore highly likely to drive significant volumes of electrolytic hydrogen, which is likely to be considered as low-GHG hydrogen in this proposal.[356] These incentives will be multiplied by investments through the DOE's H2Hub program. Based on this assessment, ample supplies are likely to be available for combustion turbine co-firing in 2035. The EPA is soliciting comment on whether sufficient

[355] DOE, as required by the IIJA, proposed a Clean Hydrogen Production Standard (CHPS) of having an overall emissions rate of 4 kg CO_2e/kg H_2. CHPS is not an actual standard, rather a non-binding tool for DOE's internal use with selecting projects under the H2Hubs program. DOE's proposed CHPS can be found at *https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf*.
[356] "The Hydrogen Credit Catalyst How US Treasury guidance on a new tax credit could shape the clean hydrogen economy, the future of American industry, and orient the power sector for full decarbonization" Rocky Mountain Institute, February 27, 2023

quantities of low-GHG hydrogen will likely be available at reasonable costs by 2030. If so, this would support moving forward the compliance date of the second component of the BSER and/or increase the percent of hydrogen co-firing assumed in establishing the standard of performance.

As explained above, a central and universally recognized feature of hydrogen is its level of GHG emissions generated during its production process, with different hydrogen production processes resulting in different levels of GHG emissions. As explained in another section in the preamble, the EPA proposes to conclude that only co-firing with low-GHG hydrogen appropriately considers the statutory factors and constitutes the "best" system of emission reduction. Here, the EPA discusses the proposed definition of "low-GHG hydrogen." In the IIJA and IRA, Congress established various programs to support the development of low-GHG hydrogen. Several federal agencies, including the EPA, are implementing those programs, as well as pre-IIJA and IRA programs that involve low-GHG hydrogen. These various programs have a range of definitions of low-GHG hydrogen. As a result, they provide useful points of reference for the EPA to use in selecting a definition for this proposed rulemaking.

In enacting the IRA, Congress recognized that different methods of hydrogen production generate different amounts of GHG emissions and sought to encourage lower-emitting production methods through the multi-tier hydrogen production tax credit (IRC section 45V). The IRC section 45V tax credits provide four tiers of tax credits, and thus award the highest amount of tax credits to the hydrogen production processes with the lowest estimated GHG emissions. The highest tier of the credits is $3/kg H_2 for 0.0 to 0.45 kg CO_2e/kg H_2 produced, and the lowest is $0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2.[357]

[357] These amounts assume that wage and apprenticeship requirements are met.

Several Federal agencies are engaging in low-GHG hydrogen-related efforts, some of which implement the IRA and IIJA provisions. As discussed earlier in this section, the DOE is working on a Clean Hydrogen Production Standard,[358] an $8 billion Clean Hydrogen Hub solicitation,[359] and several hydrogen-related research and development grant programs.[360] The Department of the Treasury is taking public comment on examining appropriate parameters for evaluating overall emissions associated with hydrogen production pathways as it prepares to implement IRC section 45V.[361] Within the EPA, there are rulemaking efforts that could impact low-GHG hydrogen production pathways, namely the proposed and supplemental oil and gas emission guidelines to reduce methane emissions.

Upon review of the reference points that these legislative provisions and agency programs provide, it is apparent that the "clean hydrogen" definition in section 822 of the IIJA is not appropriate for purposes of this rule. As noted, this provision sets out a non-binding goal for use in development of the DOE's Clean Hydrogen Production Standard (CHPS), and DOE's funding programs to promote promising new hydrogen technologies. The CHPS is limited to GHG produced at the site of the hydrogen production, and so is not intended to consider overall GHG emissions associated with that production. According to the IIJA, clean hydrogen as defined as part of the CHPS is "… hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced *at the site of production* per kilogram of hydrogen produced" (emphasis added). A significant portion of the GHG emissions associated

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[358] U.S. Department of Energy (DOE). (September 22, 2022). Clean Hydrogen Production Standard. Hydrogen and Fuel Cell Technologies Office. See *https://www.energy.gov/eere/fuelcells/articles/clean-hydrogen-production-standard*.
[359] *https://www.energy.gov/oced/regional-clean-hydrogen-hubs*.
[360] *https://www.hydrogen.energy.gov/funding_opportunities.html*.
[361] *https://home.treasury.gov/news/press-releases/jy0993*.

with hydrogen derived from natural gas originates from upstream methane emissions, which are not accounted for in the CHPS definition.[362]

In contrast, the EPA believes that the highest tier of the IRC section 45V(b)(2) production tax credit is salient for purposes of the present rule. That provision provides the highest available amount of production tax credit for hydrogen produced through a process that has a GHG emissions rate of 0.45 kg CO_2e/kg H_2 or less, from well-to-gate. As explained further below, the EPA proposes that co-firing hydrogen meeting this criteria qualifies as a component of the "best" system of emission reduction taking into account the statutory considerations. Thus, the EPA is proposing that low-GHG hydrogen is hydrogen that is produced through a process that has a GHG emissions rate of 0.45 kg CO_2e/kg H_2 or less, from well-to-gate. Each of the subsequent hydrogen production categories outlined in 45V(b)(2) convey increasingly higher amounts of GHG emissions (from a well-to-gate analysis), making them less suitable to be a component of the BSER.

Electrolyzers with various low-GHG energy inputs, like solar, wind, hydroelectric, and nuclear appear most likely to produce hydrogen that would meet the 0.45 kg CO_2e/kg H_2 or less, from well-to-gate criteria. Hydrogen production pathways using methane as a feedstock induce upstream methane emissions associated with extraction, production, and transport of the methane. SMR and ATR also release heating and process-related CO_2 emissions, which are harder to capture at high rates economically. High contributions to overall GHG emission rates may disqualify certain hydrogen production pathways from producing low-GHG hydrogen. The EPA recognizes that the pace and scale of government programs and private research suggest

[362] Infrastructure Investment and Jobs Act of 20211Law PUBL058.PS (*https://www.congress.gov*).

that we will gain significant experience and knowledge on this topic during the timeframe of this proposed rulemaking. Accordingly, the EPA is soliciting comment broadly on its proposed definition for low-GHG hydrogen, and on alternative approaches, to ensure that co-firing low-GHG hydrogen minimizes GHG emissions, and that combustion turbines subject to this standard utilize only low-GHG hydrogen.

The EPA is also taking comment on whether it is even necessary to provide a definition of low-GHG hydrogen in this rule. Given the incentives provided in both the IRA and IIJA for low-GHG hydrogen production and the current trajectory of hydrogen use in the power sector, by 2035, the start date for compliance with the proposed second phase of the standards for this rule, low-GHG hydrogen may be the most common source of hydrogen available for electricity production. For the most part, companies that have announced that they are exploring the use of hydrogen co-firing have stated that they intend to use low-GHG hydrogen. These power suppliers include NextEra, Los Angeles Department of Power and Water, and New York Power Authority, as discussed earlier in this section. Many utilities and merchant generators own nuclear, wind, solar, and hydroelectric generating sources as well as combustion turbines. The EPA has identified an emerging trend in which energy companies with this broad collection of generation assets are planning to produce low-GHG hydrogen for sale and to use a portion of it to fuel their stationary combustion turbines. This emerging trend lends support to the view that the power sector is likely to have access to and will choose to utilize low-GHG hydrogen for its co-firing applications.

Moreover, by the next decade, costs for low-GHG hydrogen are expected to be competitive with higher-GHG forms of hydrogen. Given the tax credits in IRC section 45V(b)(2)(D) of \$3/kg H_2 for hydrogen with GHG emissions of less than 0.45 kg CO_2e/kg H_2, and substantial DOE grant programs to drive down costs of clean hydrogen, electrolytic low-GHG hydrogen is projected by industry estimates to result in delivered hydrogen costs of $1/kg H_2 or less by 2030.[363] [364] These projections are more optimistic but generally consistent with the DOE's (pre-IRA) program targets of clean hydrogen production costs converging on $1/kg H_2 between 2029 and 2036 with 10 MMT of annual production by 2030, 20 MMT of annual production by 2040, and 50 MMT of annual production by 2050.[365] A growing number of studies are demonstrating more efficient and less expensive techniques to produce low-GHG electrolytic hydrogen; and, tax credits and market forces are expected to accelerate innovation and drive down costs even further over the next decade.[366] [367] The combination of competitive pricing and widespread net-zero commitments throughout the utility and merchant electricity generation market is likely to drive future hydrogen co-firing applications to be low-GHG hydrogen. The EPA is therefore soliciting comment on whether low-GHG hydrogen needs to be defined as part of the BSER in this rulemaking.

vii. Justification for Proposing 30 Percent Co-firing Low-GHG Hydrogen as the BSER

The EPA is proposing that co-firing 30 percent low-GHG hydrogen, as proposed to be defined above, by new combustion turbines in the relevant subcategories, by 2035, meets the requirements under CAA section 111(a)(1) to qualify as a component of the BSER. As discussed below, co-firing 30 percent low-GHG hydrogen is adequately demonstrated because it is feasible

[363] "US green hydrogen costs to reach sub-zero under IRA: longer-term price impacts remain uncertain," S&P Global Commodity Insights, September 29, 2022.
[364] "DOE Funding Opportunity Targets Clean Hydrogen Technologies" American Public Power, January 31, 2023.
[365] "DOE National Clean Hydrogen Strategy and Roadmap," Department of Energy, September, 2022.
[366] "Sound waves boost green hydrogen production," Power Engineering, January 4, 2023.
[367] "Direct seawater electrolysis by adjusting the local reaction environment of a catalyst," Nature Energy, January 30, 2023.

and well-demonstrated for new combustion turbines to co-fire that percentage of hydrogen, and the EPA reasonably expects that adequate quantities of low-GHG hydrogen will be available by 2035; it is of reasonable cost; it will achieve reductions because, when burned, hydrogen does not produce GHG emissions; and it will not have adverse non-air quality health or environmental impacts or energy requirements, including on the nationwide energy sector. It also creates market demand and advances the development of low GHG-hydrogen, a fuel that is useful for reducing emissions. The EPA includes in this section a more detailed justification for our definition of low-GHG hydrogen and an explanation for why the statutory considerations lead us to believe that requiring low-GHG hydrogen (as contrasted with any hydrogen) is a component of the "best" system of emission reduction.

(A) Adequately Demonstrated

As part of the present rulemaking, the EPA evaluated the ability of new combustion turbines to operate with certain percentages (by volume) of hydrogen blended into their fuel systems. This evaluation included an analysis of the technical challenges of co-firing hydrogen in a combustion turbine EGU to generate electricity. The EPA also evaluated available information to determine if adequate quantities of low-GHG hydrogen can be reasonably expected to be available for combustion turbine EGUs by 2035.

Although industrial combustion turbines have been burning byproduct fuels containing large percentages of hydrogen for decades, utility combustion turbines have only recently begun to co-fire smaller amounts of hydrogen as a fuel to generate electricity. The primary technical challenges of hydrogen co-firing are related to certain physical characteristics of the gas. Hydrogen fuel produces a higher flame speed when combusted than the flame speed produced with the combustion of natural gas; and hydrogen typically combusts at a faster rate than natural gas. When the combustion speed is faster than the flow rate of the fuel, a phenomenon known as "flashback" can occur, which can lead to upstream complications.[368] Hydrogen also has a higher flame temperature and a wider flammability range compared to natural gas.[369]

The industrial combustion turbines currently burning hydrogen are smaller than the larger utility combustion turbines and use diffusion flame combustion, often in combination with water injection, for NO_X control. While water injection requires demineralized water and is generally only a NO_X control option for simple cycle turbines, existing simple cycle combustion turbines have successfully demonstrated that relatively high levels of hydrogen can be co-fired in combustion turbines using diffusion flame and supports the EPA's proposal to determine that co-firing 30 percent hydrogen is technically feasible for new base load and intermediate load stationary combustion turbine EGUs by 2035.

The more commonly used NO_X combustion control for base load combined cycle turbines is dry low NO_X (DLN) combustion. Even though the ability to co-fire hydrogen in combustion turbines that are using DLN combustors to reduce emissions of NO_X is currently more limited, all major combustion turbine manufacturers have developed DLN combustors for utility EGUs that can co-fire hydrogen.[370] Moreover, the major combustion turbine manufacturers are designing combustion turbines that will be capable of combusting 100 percent

[368] Inoue, K., Miyamoto, K., Domen, S., Tamura, I., Kawakami, T., & Tanimura, S. (2018). *Development of Hydrogen and Natural Gas Co-firing Gas Turbine*. Mitsubishi Heavy Industries Technical Review. Volume 55, No. 2. June 2018. Accessed at *https://power.mhi.com/randd/technical-review/pdf/index_66e.pdf*.
[369] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines*. Accessed at *http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf*.
[370] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/*.

hydrogen by 2030, with DLN designs that assure acceptable levels of NO_X emissions.[371] [372] Several developers have announced installations with plans to initially co-fire lower percentages of low-GHG hydrogen by volume before gradually increasing their co-firing percentages—to as high as 100 percent in some cases—depending on the pace of the anticipated expansion of low-GHG hydrogen production processes and associated infrastructure. The goals of equipment manufacturers and the fact that existing combined cycle combustion turbines have successfully demonstrated the ability to co-fire various percentages of hydrogen supports the EPA's proposal to determine that co-firing 30 percent hydrogen is technically feasible for new base load stationary combustion turbine EGUs by 2035.

The combustion characteristics of hydrogen can lead to localized higher temperatures during the combustion process. These "hotspots" can increase emissions of the criteria pollutant NO_X.[373] NO_X emissions resulting from the combustion of high percentage by volume blends of hydrogen are also of concern in many regions of the country. For turbines using diffusion flame combustion, water injection is used to control emissions of NO_X. The level of water injection can be varied for different levels of NO_X control and adjustments can be made to address any potential increases in NO_X that would occur from co-firing hydrogen in combustion turbines using diffusion flame combustion. As stated previously, all major combustion turbine manufacturers have developed DLN combustors for utility EGUs that can co-fire hydrogen, and

[371] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030.* Accessed at *https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/*.
[372] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines.* Accessed at *https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/*.
[373] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. Accessed at *https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/*.

are designing combustion turbines that will be capable of combusting 100 percent hydrogen by 2030, with DLN designs that assure acceptable levels of NO_X emissions. Furthermore, while DLN combustion is able to achieve low levels of NO_X, the majority of new intermediate load and base load combustion turbines using DLN combustion also use selective catalytic reduction (SCR) to reduce NO_X emissions even further. The design level of control from SCR can be tied to the exhaust gas concentration. At higher levels of incoming NO_X, either the reagent injection rate can be increased and/or the size of the catalyst bed can be increased.[374] The EPA has concluded that any potential increases in NO_X emissions do not change the Agency's view that on balance, co-firing 30 percent low-GHG hydrogen qualifies as a component of the BSER.

As noted above, at present, most of the hydrogen produced in the U.S. is produced for the industrial sector through SMR, which is a high GHG-emitting process. Limited quantities of hydrogen are currently being produced via SMR with CCS, which reduces some, but not all, of the associated GHG-emitting processes. Only small-scale facilities are currently producing hydrogen through electrolysis with renewable or nuclear energy, and as described below, much larger facilities are under development.

However, as also noted above, incentives in recent Federal legislation are anticipated to significantly increase the availability of low-GHG hydrogen by 2035, including for the utility power sector. The IIJA, enacted in 2021, allocated more than $9 billion to the DOE for research, development, and demonstration of low-GHG hydrogen technologies and the creation of at least four regional low-GHG hydrogen hubs. The DOE has indicated its intention to fund between six

[374] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/*.

and 10 hubs.[375] In addition, the IRA provided significant incentives to invest in low-GHG hydrogen production (For additional discussion of the IIJA and/or IRA, see section IV.E of this preamble.)

Programs from the IIJA and IRA have been successful in inciting new low-GHG hydrogen projects and infrastructure. As of August 2022, 374 new projects had been announced that would produce 2.2 megatons (Mt) of low-GHG hydrogen, which represents a 21 percent increase over current output.[376] Examples include:

- In June 2022, the DOE issued a $504.4 million loan guarantee to finance Advanced Clean Energy Storage (ACES), a low-GHG hydrogen production and long-term storage facility in Delta, Utah.[377] The facility will use 220 MW of electrolyzers powered by renewable energy to produce low-GHG hydrogen. The hydrogen will be stored in salt caverns and serve as a long-term fuel supply for the combustion turbine at the Intermountain Power Agency (IPA) project, which is described earlier in this section.
- In January 2023, NextEra announced an 800-MW solar project in the central U.S. to support the development of low-GHG hydrogen as well as plans to produce its own low-GHG hydrogen at a facility in Arizona.[378]T.

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[375] U.S. Dept. of Energy, Regional Clean Hydrogen Hubs. *https://www.energy.gov/oced/regional-clean-hydrogen-hubs*.
[376] Energy Futures Initiative (February 2023). *U.S. Hydrogen Demand Action Plan*. Accessed at *https://energyfuturesinitiative.org/reports/*.
[377] U.S. Department of Energy (DOE). (2022). Loan Office Programs. Advanced Clean Energy Storage. See *https://www.energy.gov/lpo/advanced-clean-energy-storage*.
[378] Penrod, Emma. (January 30, 2023). *NextEra charts path for renewables expansion, but campaign finance allegations loom in the background*. Utility Dive. Accessed at *https://www.utilitydive.com/news/nextera-renewables-expansion-green-hydrogen-solar-alleged-campaign-finance-violation/641475/*.

- In New York, Constellation (formerly Exelon Generation) is exploring the potential benefits of integrating onsite low-GHG hydrogen production, storage, and usage at its Nine Mile Point nuclear station. The project is funded by a DOE grant and includes partners such as Nel Hydrogen, Argonne National Laboratory, Idaho National Laboratory, and the National Renewable Energy Laboratory. The project is expected to generate an economical supply of low-GHG hydrogen that will be safely captured, stored, and potentially taken to market as a source of power for other purposes, including industrial applications such as transportation.[379]
- Bloom Energy began installation of a 240-kW electrolyzer at Xcel Energy's Prairie Island nuclear plant in Minnesota in September 2022 to produce low-GHG hydrogen. The demonstration project, designed to create "immediate and scalable pathways" for producing cost-effective hydrogen, is expected to be operational in 2024 and is also funded with a DOE grant.[380]
- In California, Sempra subsidiary SoCalGas has announced plans to develop the nation's largest hydrogen infrastructure system called "Angeles Link." When operational, the project will provide enough hydrogen to convert up to four natural gas-fired power plants. Developers predict the increased access to hydrogen will also displace 3 million gallons of diesel fuel from heavy-duty trucks.[381] [382]

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[379] See *https://www.exeloncorp.com/newsroom/Pages/DOE-Grant-to-Support-Hydrogen-Production-Project-at-Nine-Mile-Point.aspx*.
[380] See *https://www.utilitydive.com/news/bloom-energy-hydrogen-xcel-nuclear-prairie-island/632148/*.
[381] See *https://www.socalgas.com/sustainability/hydrogen/angeles-link*.
[382] Penrod, Emma. (February 18, 2022). *SoCalGas begins developing 100% clean hydrogen pipeline system*. Utility Dive. Accessed at *https://www.utilitydive.com/news/socalgas-begins-developing-100-clean-hydrogen-pipeline-system/619170/*.

- In December 2022, Air Products and AES announced plans to build a $4-billion low-GHG hydrogen production facility at the site of a former coal-fired power plant in Texas.[383] [384] The plant is expected to be completed in 2027, and once operational, will produce approximately 200 metric tons of low-GHG hydrogen per day from electrolyzers powered by 1.4 GW of wind and solar energy, as noted earlier. This follows an announcement by Air Products in October 2022 to invest $500 million in a low-GHG hydrogen production facility in New York. This 35 metric-ton-per-day project is also expected to be operational by 2027, and in July 2022, received approval from the New York Power Authority for 94 MW of hydroelectric power.[385]
- The DOE National Clean Hydrogen Strategy and Roadmap identified a plausible path forward for the production of 10 MMT of low-GHG hydrogen annually by 2030, 20 MMT annually by 2040, and 50 MMT annually by 2050.
- The H2@Scale is a DOE initiative that brings together stakeholders to advance affordable hydrogen production, transport, storage, and utilization to enable decarbonization and revenue opportunities across multiple sectors.

These legislative actions, utility initiatives, and industrial sector production and infrastructure projects indicate that sufficient low-GHG hydrogen and sufficient distribution

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[383] McCoy, Michael. (December 8, 2022). *Air Products plans big green hydrogen plant in U.S.* Chemical and Engineering News. Accessed at *https://cen.acs.org/energy/hydrogen-power/Air-Products-plans-big-green/100/web/2022/12*.
[384] Air Products (December 8, 2022). *Air Products and AES Announce Plans to Invest Approximately $4 Billion to Build First Mega-scale Green Hydrogen Production Facility in Texas*. Accessed at *https://www.airproducts.com/news-center/2022/12/1208-air-products-and-aes-to-invest-to-build-first-mega-scale-green-hydrogen-facility-in-texas/*.
[385] Air Products (October 6, 2022). *Air Products to Invest About $500 Million to Build Green Hydrogen Production Facility in New York*. Accessed at *https://www.airproducts.com/news-center/2022/10/1006-air-products-to-build-green-hydrogen-production-facility-in-new-york*.

infrastructure can reasonably be expected to be available by 2035 so that, at a minimum, the majority of new combustion turbines could co-fire low-GHG hydrogen. The EPA specifically solicits comment on whether rural areas and small utility distribution systems (serving 50,000 customers or less) can expect to have access to low-GHG hydrogen or if infrastructure will be limited to areas with higher population densities.

By 2035, substantial additional amounts of renewable energy are expected to be available, which can support the production of low-GHG hydrogen through electrolysis. For example, in the EPA's post-IRA 2022 reference case projections, non-hydroelectric utility-scale renewable capacity is projected to increase from 209 GW in 2021 to 668 GW by 2035 and then to 1,293 GW by 2050 (See section IV.F of this preamble for additional discussion of the EPA's post-IRA 2022 reference case).

(B) Costs

There are three sets of potential costs associated with co-firing hydrogen in combustion turbines: (i) the capital costs of combustion turbines that have the capability of co-firing hydrogen; (ii) pipeline infrastructure to deliver hydrogen; and (iii) the fuel costs related to production of low-GHG hydrogen.

As stated previously, manufacturers are already developing combustion turbines that can co-fire up to approximately 30 to 50 percent hydrogen by volume. Accordingly, no additional costs arise from this aspect. The EPA is soliciting comment on additional costs required to co-fire between 30 to 50 percent hydrogen and if there are efficiency impacts from co-firing hydrogen.

With respect to pipeline infrastructure, there are approximately 1,600 miles of dedicated hydrogen pipelines currently operating in the U.SExisting natural gas infrastructure may be capable of accepting blends of hydrogen with modest investments, but the actual limits will vary depending on pipeline materials, age, and operating conditions.

investments.[387] Due to the lower energy density of hydrogen relative to natural gas, the piping required to deliver pure hydrogen would have to be larger, and the material used to construct the piping could need to be specifically designed to be able to handle higher concentrations of hydrogen that would prevent embrittlement and leaks. These risks can be mitigated through deployment of new pipeline infrastructure designed for compatibility with hydrogen in support of a new combustion turbine installations. The majority of announced combustion turbine EGU projects proposing to co-fire hydrogen are located close to the source of hydrogen. Therefore, the fuel delivery systems (*i.e.*, pipes) for new combustion turbines can be designed to transport 30 percent hydrogen without additional costs. Therefore, the EPA proposes that co-firing rates of 30 percent by volume or less would have limited, if any, additional capital costs for new combustion turbine EGU projects. The EPA is soliciting comment on if additional infrastructure costs should be accounted for when determining the costs of hydrogen co-firing.

The primary cost for co-firing hydrogen is the cost of hydrogen relative to natural gas. The cost of delivered hydrogen depends on the technology used to produce the hydrogen and the cost to transport the hydrogen to the end user. For context, the DOE National Clean Hydrogen Strategy and Roadmap cites the current cost of low-GHG electrolytic hydrogen production at approximately $5/kg. The DOE has projected a goal of reducing the cost of low-GHG hydrogen productionto $1/kg (equivalent to $7.4/MMBtu) by 2030, which is approximately the same as the current production costs of hydrogen from SMR. Using $1/kg (equivalent to $7.4/MMBtu) as the

[387] *https://www.energy.gov/eere/fuelcells/hydrogen-pipelines*.

delivered cost of low-GHG hydrogen, co-firing 30 percent hydrogen in a combined cycle EGU operating at a capacity factor of 65 percent would increase both the levelized cost of electricity (LCOE) and the variable operating costs by \$2.9/MWh.[388] This is a 6 percent increase from the baseline LCOE and an 11 percent increase from the baseline variable operating costs. This is equivalent to a CO_2 abatement cost of \$64/ton (\$70/tonne) at the affected facility[389]. For an aeroderivative simple cycle combustion turbine operating at a capacity factor of 40 percent, co-firing 30 percent hydrogen increases the LCOE and variable operating costs by \$4.1/MWh, representing a 5 percent increase from the baseline LCOE and an 11 percent increase from the baseline variable operating costs.

However, DOE's projected goal of \$1/kgproduction costs (equivalent to \$7.4/MMBtu) for low-GHG hydrogen was established prior to the IIJA incentives and IRA tax subsidies for low-GHG hydrogen production, CCS, and generation from renewable sources. These subsidies could be equivalent to, or even exceed, the production costs of low-GHG hydrogen. Even when the cost to transport the hydrogen from the production facility to the end user is accounted for, the cost of low-GHG hydrogen to the end user could be less than \$1/kg. Assuming a delivered price of \$0.75/kg (\$5.6/MMBtu), the CO_2 abatement costs for co-firing hydrogen in a combined cycle and simple cycle EGU would be \$32/ton (\$35/tonne), respectively. If the delivered cost of low-GHG hydrogen is \$0.50/kg (\$3.7/MMBtu), this would represent cost parity with natural gas and abatement costs would be zero.

The EPA is proposing to determine that the increase in operating costs from a BSER based on co-firing 30 percent low-GHG hydrogen is reasonable.

[388] The EIA long-term natural gas price for utilities is \$3.69/MMBtu.
[389] The abatement cost of co-firing low-GHG hydrogen is determined by the relative delivered cost of the low-GHG hydrogen and natural gas.

(C) Non-air Quality Health and Environmental Impact and Energy Requirements

The non-air quality health and environmental impacts and energy requirements vary based on the technology that is used to produce the hydrogen. Multiple hydrogen production pathways use methane as a feedstock, including SMR, ATR, and pyrolysis. Methane extraction operations are known to contribute to air toxics including benzene, ethylbenzene, and n-hexane.[390] Aside from methane pyrolysis and byproduct hydrogen, other hydrogen production methods consume water during the production process and indirectly due to electricity generation upstream.[391] Electrolysis and other technologies that break apart water to form hydrogen and oxygen consume the most water, at least 9 kg of water per 1 kg of hydrogen produced, which is twice the water requirements of SMR. without CCS. The EPA does not consider the additional water demands to be unreasonable. Costs associated with water supply will be reflected in the cost of producing the low-GHG hydrogen, which, as noted above, is reasonable. If water-intensive hydrogen production methods are impractical in certain areas of the country where new affected combustion turbines are located, low-GHG hydrogen can be transported into those areas through pipelines.

The creation of hydrogen is an energy-intensive process. Moreover, inherent thermodynamic inefficiencies mean that more energy is needed to make a quantity of hydrogen for use in a combustion turbine than the amount of energy that would be consumed by a combustion turbine if it were to burn natural gas directly. In the case of pyrolysis and electrolysis, if that energy is supplied by renewable or nuclear power, adverse energy impacts

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[390] *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/basic-information-oil-and-natural-gas*.

[391] The moisture present in coal and biomass could be recovered and used in the water gas shift reaction to reduce (or eliminate) water requirements.

could arise, under certain circumstances, if that energy could otherwise have displaced fossil fuel-fired electricity been deployed directly on the grid. The EPA does not consider these impacts will be unreasonable or unduly concerning for the grid in 2035. The EPA's post-IRA 2022 reference case projects 668 GW of new renewable generation by 2035. Given this influx, coupled with expected fossil fuel-fired EGU retirements, the carbon intensity of the grid would be correspondingly lower, mitigating concerns about energy-intense hydrogen production displacing clean energy from the grid. Moreover, incentives for low-GHG hydrogen will likely encourage more renewable development.

The EPA has also considered the impact of determining co-firing 30 percent low-GHG hydrogen as a component of the BSER on the energy sector. Because combustion turbines can be constructed to co-fire this amount of hydrogen in lieu of natural gas, this BSER would not have adverse impacts on the structure of the energy sector.

(D) Extent of Reductions in CO_2 Emissions

The site-specific reduction in CO_2 emissions achieved by a combustion turbine co-firing hydrogen is dependent on the volume of hydrogen blended into the fuel system. and the lifecycle emissions of the hydrogen. Due to the lower energy density by volume of hydrogen compared to natural gas, an affected source that combusts 30 percent by volume hydrogen with natural gas would achieve approximately a 12 percent reduction in CO_2 emissions versus firing 100 percent natural gas.[392] [393]

[392] The energy density by volume of hydrogen is lower than natural gas.
[393] A source combusting 100 percent hydrogen would have zero CO_2 stack emissions because hydrogen contains no carbon, as previously discussed. A source co-firing 90 percent by volume hydrogen with natural gas would achieve a 75 percent reduction in CO_2 emissions; a 75 percent by volume blend would reduce CO_2 by 50 percent.

(E) Promotion of the Development and Implementation of Technology

Determining co-firing 30 percent low-GHG hydrogen to be a component of the BSER would generally advance technology development in both the production of low-GHG hydrogen and the use of hydrogen in combustion turbines. This would facilitate co-firing larger amounts of low-GHG hydrogen and facilitate co-firing low-GHG hydrogen in existing combustion turbines. Developing new configurations for flame dimensions and turbine modifications to adjust for the characteristics unique to hydrogen combustion are technology forcing advancements that industry appears to be already leaning into based on the project announcements. Thus, co-firing 30 percent low-GHG hydrogen fulfills the requirements of BSER to generally advance technology development. In addition, co-firing 30 percent low-GHG hydrogen would promote co-firing additional amounts of low-GHG hydrogen. As discussed in the preceding section, there are over 18GW of projects planned by industry to co-fire turbines with 30 percent hydrogen initially and progress to firing with 100 percent hydrogen. Fueling combustion turbines with 100 percent hydrogen would eliminate all carbon dioxide stack emissions. It would also promote reliability because it would and provide grid operators with asset options, in addition to battery and energy storage, capable of voltage support and frequency regulation. These are asset characteristics that will be required in increasing capacities as more variable generation is deployed.

(F) Co-firing Low-GHG Hydrogen, Rather Than Any Hydrogen, Is the "Best" System of Emissions Reduction

In this section, the EPA explains further why the type of hydrogen co-fired as a component of the BSER must be limited to low-GHG hydrogen, and not other types of hydrogen. The EPA explains further the proposed definition of low-GHG hydrogen as 0.45 kg

$CO_2e/kg\ H_2$ or less from the production of hydrogen, from well-to-gate. Finally, the Agency summarizes the reasons, described above, for the proposal that co-firing 30 percent low-GHG hydrogen meets the criteria under CAA section 111 as the BSER.

(1) Limitation of Co-firing to Low-GHG Hydrogen

Hydrogen is a zero-GHG emitting fuel when combusted, so that co-firing it in a combustion turbine in place of natural gas reduces GHG emissions at the stack. Co-firing low-emitting fuels – sometimes referred to as clean fuels – is well-recognized as an acceptable type of emissions control, including as a system of emission reduction under CAA section 111. In *West Virginia v. EPA*, the Supreme Court noted with approval a statement the EPA made in the Clean Power Plan that “fuel-switching” was one of the “more traditional air pollution control measures.” 142 S. Ct. at 2611 (quoting 80 FR 64784; October 23, 2015). The EPA has relied on lower-emitting fuels as the BSER in several CAA section 111 rules. See 44 FR 33580, 33593 (June 11, 1979) (coal that undergoes washing prior to its combustion to remove sulfur, so that its combustion emits fewer SO_2 emissions); 72 FR 32742 (June 13, 2007) (same); 2015 NSPS (natural gas and clean fuel oil).

In the present proposal, the EPA recognizes that even though the combustion of hydrogen is zero-GHG emitting, its production entails a range of GHG emissions, from low to high, depending on the method. As noted above, the differences in GHG emissions from the different methods of hydrogen production are well recognized in the energy sector, and, in fact, hydrogen is generally characterized by its production method and the attendant level of GHG emissions.

Accordingly, the EPA is proposing to require that to qualify as the “best” system of emission reduction, the hydrogen that is co-fired must be low-GHG hydrogen, as defined above. This is because the purpose of CAA section 111 is to reduce pollution that endangers human health and welfare to the extent achievable, CAA section 111(b), through promulgation of standards of performance that reflect the "best system of emission reduction" that, taking into account certain factors, is adequately demonstrated. CAA section 111(a)(1). Co-firing hydrogen at a combustion turbine when that hydrogen is produced with large amounts of GHG emissions would yield the anomalous result of increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine. Therefore, in evaluating a "system of emission reduction" of co-firing hydrogen, the GHG emissions from producing the hydrogen should be recognized to determine whether co-firing that hydrogen is the "best" system of emission reduction, within the meaning of CAA section 111(a)(1).

D.C. Circuit caselaw supports applying the term "best" in this manner. In several cases decided under CAA section 111(a)(1) as enacted by the 1970 CAA Amendments, which did not provide that the EPA must consider non-air quality health and environmental impacts in determining the BSER,[394] the court stated that the EPA must consider whether byproducts of pollution control equipment could cause environmental damage in determining whether the pollution control equipment qualified as the best system of emission reduction. *See Portland Cement v. Ruckelshaus*, 465 F.2d 375, 385 n.42 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974) (stating that "[t]he standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that "best" could apply to a system which did more damage to water than

[394] As enacted under the 1970 CAA Amendments, CAA section 111(a)(1) read as follows:

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.

In the 1977 CAA Amendments, Congress revised section 111(a)(1) to incorporate a reference to "non-air quality health and environmental impacts," and Congress retained that phrase in the 1990 CAA Amendments when it revised CAA section 111(a)(1) to read as it currently does.

it prevented to air"); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 439 (D.C. Cir. 1973) (remanding because the EPA failed to consider "the significant land or water pollution potential" from byproducts of air pollution control equipment). The situation here is analogous because a standard that allowed for co-firing with other hydrogen would create more damage than it prevented, the precise problem CAA section 111 is intended to address. Considering the overall emissions impact of the production of fuel used by the affected facility to lower its emissions—here, hydrogen—is consistent with considering the environmental impacts of the byproducts of pollution control technology used by the affected facility to lower its emissions.

In addition, the EPA's proposed determination that co-firing low-GHG hydrogen qualifies as the BSER is supported by the IRA and its legislative history. In the IRA, Congress enacted or expanded tax credits to encourage the production and use of low-GHG hydrogen.[395] In addition, as discussed in section IV.E.1 of this preamble, IRA section 60107 added new CAA section 135, LEEP. This provision provides $1 million for the EPA to assess the GHG emissions reductions from changes in domestic electricity generation and use anticipated to occur annually through fiscal year 2031; and further provides $18 million for the EPA to promulgate additional CAA rules to ensure GHG emissions reductions that go beyond the reductions expected in that assessment. CAA section 135(a)(5)-(6). The legislative history of this provision makes clear that Congress anticipated that the EPA could promulgate rules under CAA section 111(b) to ensure GHG emissions reductions from fossil fuel-fired electricity generation. 168 Cong. Rec. E879

[395] These tax credits include IRC section 45V (tax credit for production of hydrogen through low- or zero-emitting processes), IRC section 48 (tax credit for investment in energy storage property, including hydrogen production), IRC section 45Q (tax credit for CO_2 sequestration from industrial processes, including hydrogen production); and the use of hydrogen in transportation applications, IRC section 45Z (clean fuel production tax credit), IRC section 40B (sustainable aviation fuel credit).

(August 26, 2022) (statement of Rep. Frank Pallone, Jr.). The legislative history goes on to state that "Congress anticipates that EPA may consider … clean hydrogen as [a] candidate[] for BSER for electric generating plants…." *Id.*

Most broadly, proposing that only low-GHG hydrogen qualifies as part of the co-firing BSER is required by the "reasoned decisionmaking" that the Supreme Court has long held, including recently in *Michigan v. EPA* 576 U.S. 743 (2015), that "[f]ederal administrative agencies are required to engage in." *Id*. at 751 (internal quotation marks omitted and citation omitted). In *Michigan*, the Court held that CAA section 112(n)(1)(A), which directs the EPA to regulate hazardous air pollutants from coal-fired power plants if the EPA "finds such regulation is appropriate and necessary," must be interpreted to require the EPA to consider the costs of the regulation. The Court explained that if the EPA failed to consider cost, it could promulgate a regulation to eliminate power plant emissions harmful to human health, but do so through the use of technologies that "do even more damage to human health" than the emissions they eliminate. *Id*. at 752. The Court emphasized, "No regulation is 'appropriate' if it does significantly more harm than good." *Id*. Here, as explained above, permitting EGUs to burn high-GHG hydrogen would "do even more damage to human health" than the emissions eliminated and therefore could not be considered "reasoned decisionmaking." *Id.* at 751. Likewise, the Supreme Court has long said that an agency engaged in reasoned decisionmaking may not ignore "an important aspect of the problem." *Motor Vehicles Mfrs. Ass'n v. State Farm Auto Ins. Co.*, 463 U.S. 29, 43 (1983). Permitting EGUs to burn high-GHG hydrogen to meet the emissions standard here would ignore an important aspect of the problem being addressed, contrary to reasoned decisionmaking.

(2) Definition of Low-GHG Hydrogen

As noted in section of VII.F.3.c.vi. of this preamble, the EPA proposes a definition for low-GHG hydrogen that aligns with the highest of the four tiers of tax credit available for hydrogen production, IRC section 45V(b)(2)(D). Under this provision, taxpayers are eligible for a tax credit of $3 per kilogram of hydrogen that is produced with a GHG emissions rate of 0.45 kg CO_2e/kg H_2 or less, from well-to-gate. This amount is three times higher than the amount for the next tier of credit, which is for hydrogen produced with a GHG emissions rate between 1.5 and 0.45 kg CO_2e/kg H_2, from well-to-gate, IRC section 45V(b)(2)(C); and four and five times higher than the amount for the next two tiers of credit, respectively. IRC section 45V(b)(2)(B), (A). With these provisions, Congress indicated its judgement as to what constitutes the lowest-GHG hydrogen production, and its intention to incentivize production of that type of hydrogen. Congress's views inform the EPA's proposal to define low-GHG hydrogen for purposes the BSER for this CAA section 111 rulemaking consistent with IRC section 45V(b)(2)(D).

It should be noted that the EPA is not proposing that the "clean hydrogen" definition in section 822 of the IIJA is appropriate for the EPA's regulatory purposes. This definition is designed for a non-regulatory purpose. It sets out a non-binding goal, not a standard or a regulatory definition, intended for use in development of the DOE's CHPS and funding programs to promote promising new hydrogen technologies.

For the reasons discussed above, co-firing 30 percent low-GHG hydrogen qualifies as the BSER because it is adequately demonstrated, is of reasonable cost, does not have adverse non-air quality health or environmental impacts or energy requirements—in fact, it offers potential benefits to the energy sector—and reduces GHG emissions. The fact that this control promotes the advancement of low-GHG production and deployment provides additional, although not essential, support for proposing it as part of the BSER. Finally, Congress's direction to choose the "best" system of emissions reduction and principles of reasoned decision-making dictate that the standard should be based on burning low-GHG hydrogen, and not other hydrogen.

4. Other Options for BSER

The EPA considered several other systems of emission reduction as candidates for the BSER for combustion turbines, but is not proposing them as the BSER. They include CHP and the hybrid power plant, as discussed below.

a. Combined Heat and Power (CHP)

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP has lower emission rates and can be more economic than separate electric and thermal generation. However, a critical requirement for a CHP facility is that it primarily generates thermal output and generates electricity as a byproduct and must therefore be physically close to a thermal host that can consistently accept the useful thermal output. It can be particularly difficult to locate a thermal host with sufficiently large thermal demands such that the useful thermal output would impact the emissions rate. The refining, chemical manufacturing, pulp and paper, food processing, and district energy systems tend to have large thermal demands. However, the thermal demand at these facilities is generally only sufficient to support a smaller EGU, approximately a maximum of several hundred MW. This would limit the geographically available locations where new generation could be constructed in addition to limiting its size. Furthermore, even if a sufficiently large thermal host were in close proximity, the owner/operator of the EGU would be required to rely on the continued operation of the thermal host for the life of the EGU. If the thermal host were to shut down, the EGU could be unable to comply with the emissions standard. This reality would likely result in difficulty in securing funding for the construction of the EGU and could also lead the thermal host to demand discount pricing for the delivered useful thermal output. For these reasons, the EPA is not proposing CHP as the BSER.

b. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (*e.g.*, concentrating solar thermal) with a fossil fuel-fired EGU. Both coal-fired and NGCC EGUs have operated using the integration of concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps.

One of the benefits of integrating solar thermal with a fossil fuel-fired EGU is the lower capital and operation and maintenance (O&M) costs of the solar thermal technology. This is due to the ability to use equipment (*e.g.*, HRSG, steam turbine, condenser, *etc.*) already included at the fossil fuel-fired EGU. Another advantage is the improved electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures, and the conversion of the thermal energy in the steam to electricity is relatively low. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HSRG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low-grade steam produced by the solar thermal facility in the boiler improves the relative conversion efficiencies of the solar thermal to electricity process.

The primary incremental costs of the non-emitting generation in a hybrid power plant are the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than that in a comparable fossil-only EGU to accommodate the additional steam load during sunny hours. A drawback of integrating solar thermal is that the larger steam turbine will operate at part loads and reduced efficiency when no steam is provided from the solar thermal panels (*i.e.*, the night and cloudy weather). This limits the amount of solar thermal that can be integrated into the steam cycle at a fossil fuel-fired EGU.

In the 2018 Annual Energy Outlook,[396] the levelized cost of concentrated solar power (CSP) without transmission costs or tax credits is $161/MWh. Integrating solar thermal into a fossil fuel-fired EGU reduces the capital cost and O&M expenses of the CSP portion by 25 and 67 percent compared to a stand-alone CSP EGU respectively.[397] This results in an effective LCOE for the integrated CSP of $104/MWh. Assuming the integrated CSP is sized to provide 10 percent of the maximum steam turbine output and the relative capacity factors of a NGCC and the CSP (those capacity factors are 65 and 25 percent, respectively) the overall annual generation due to the concentrating solar thermal would be 3 percent of the hybrid EGU output. This would result in a three percent reduction in the overall CO_2 emissions and a one percent increase in the LCOE, without accounting for any reduction in the steam turbine efficiency. However, these costs do not account for potential reductions in the steam turbine efficiency due to being oversized relative to a non-hybrid EGU. A 2011 technical report by the National Renewable Energy Laboratory (NREL) cited analyses indicating solar-augmentation of fossil power stations

[396] EIA, Annual Energy Outlook 2018, February 6, 2018, available at *https://www.eia.gov/outlooks/aeo/*.
[397] B. Alqahtani and D. Patiño-Echeverri, Duke University, Nicholas School of the Environment, "Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar," Applied Energy 169:927–936 (2016).

is not cost-effective, although likely less expensive and containing less project risk than a stand-alone solar thermal plant. Similarly, while commenters stated that solar augmentation has been successfully integrated at coal-fired plants to improve overall unit efficiency, commenters did not provide any new information on costs or indicate that such augmentation is cost-effective.

In addition, solar thermal facilities require locations with abundant sunshine and significant land area in order to collect the thermal energy. Existing concentrated solar power projects in the U.S. are primarily located in California, Arizona, and Nevada with smaller projects in Florida, Hawaii, Utah, and Colorado. NREL's 2011 technical report on the solar-augment potential of fossil-fired power plants examined regions of the U.S. with "good solar resource as defined by their direct normal insolation (DNI)" and identified sixteen states as meeting that criterion: Alabama, Arizona, California, Colorado, Florida, Georgia, Louisiana, Mississippi, Nevada, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, and Utah. The technical report explained that annual average DNI has a significant effect on the performance of a solar-augmented fossil plant, with higher average DNI translating into the ability of a hybrid power plant to produce more steam for augmenting the plant. The technical report used a points-based system and assigned the most points for high solar resource values. An examination of a NREL-generated DNI map of the U.S. reveals that states with the highest DNI values are located in the southwestern U.S., with only portions of Arizona, California, Nevada, New Mexico, and Texas (plus Hawaii) having solar resources that would have been assigned the highest points by the NREL technical report (7 kWh/m2/day or greater).

The EPA is not proposing hybrid power plants as the BSER because of the limited amount of emission reductions, on a nationwide basis, that the technology offers. Gaps in the

EPA's knowledge about costs, and concerns about the cost-effectiveness of the technology, as noted above, also point away from proposing the technology as the BSER.

G. Proposed Standards of Performance

Once the EPA has determined that a particular system or technology represents BSER, the CAA authorizes the Administrator to establish standards of performance for new units that reflect the degree of emission limitation achievable through the application of that BSER. As noted above, the EPA proposes that because the technology for reducing GHG emissions from combustion turbines is advancing rapidly, a two-phase set of standards of performance, which reflect a two-component BSER, is appropriate for base load and intermediate load combustion turbines. Under this approach, for the first phase of the standards, which applies as of the effective date the final rule, the BSER is highly efficient generation for both base load and intermediate load combustion turbines. During this phase, owners/operators of EGUs will be subject to a numeric emissions standard that is representative of the performance of the best performing EGUs in the subcategory. For the second phase of the standards, beginning in 2035, the BSER for base load turbines includes either 90 percent capture CCS or 30 percent low-GHG hydrogen co-firing, and the BSER for intermediate load EGUs includes 30 percent low-GHG hydrogen co-firing. The affected EGUs would be subject to either an emissions rate that reflects continued use of highly efficient generation coupled with CCS, or one that reflects continued use of highly efficient generation coupled with co-firing low-GHG hydrogen. In addition, the EPA is proposing a single component BSER, applicable from the date of proposal, for low load combustion turbines.

1. Phase-1 Standards

The first component of the BSER is the use of highly efficient combined cycle technology for base load EGUs in combination with the best operating and maintenance practices, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices for intermediate load EGUs, and the use of clean fuels for low load EGUs.

For new and reconstructed natural gas-fired base load combustion turbine EGUs, the EPA proposes to find that the most efficient available combined cycle technology—which qualifies as the BSER for base load combustion turbines—supports a standard of 770 lb CO_2/MWh-gross for large natural gas-fired EGUs (*i.e.*, those with a nameplate heat input greater than 2,000 MMBtu/h) and 900 lb CO_2/MWh-gross for natural gas-fired small EGUs (*i.e.*, those with a nameplate base load rating of 250 MMBtu/h or less). The proposed emissions standard for natural gas-fired base load EGUs with base load ratings between 250 MMBtu/h and 2,000 MMBtu/h would be between 900 and 770 lb CO_2/MWh-gross and be determined based on the base load rating of the combustion turbine.[398] The EPA proposes to find that the most efficient available simple cycle technology—which qualifies as the BSER for intermediate load combustion turbines—supports a standard of 1,150 lb CO_2/MWh-gross for natural gas-fired EGUs. For new and reconstructed low load combustion turbines, the EPA proposes to find that the use of clean fuels—which qualifies as the BSER—supports a standard that ranges from 120

[398] A new small natural gas-fired base load EGU would determine the facility emissions rate by (1) taking the difference in the base load rating and 250 MMBtu/h, multiplying that number by 0.0743 lb CO_2/(MW * MMBtu), and subtracting that number from 900 lb CO_2/MWh. The emissions rate for a NGCC EGU with a base load rating of 1,000 MMBtu/h is 900 lb CO_2/MWh minus 750 MMBtu/h (1,000 MMBtu/h–250 MMBtu/h) times 0.0743 lb CO_2/(MW * MMBtu), which results in an emissions rate of 844 lb CO_2/MWh.

lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fuel burned. The EPA proposes these standards to apply at all times and compliance to be determined on a 12-operating-month rolling average basis.

The EPA has determined that these emission standards are achievable specifically for natural gas-fired base load and intermediate load combustion turbine EGUs. However, combustion turbine EGUs burn a variety of fuels, including fuel oil during natural gas curtailments. Owners/operators of combustion turbines burning fuels other than natural gas would not necessarily be able to comply with the proposed standards for base load and intermediate load natural gas-fired combustion turbines using highly efficient generation. Therefore, the Agency is proposing that owners/operators of combustion turbines burning fuels other than natural gas may elect to use the ratio of the heat input-based emissions rate of the specific fuel(s) burned to the heat input-based emissions rate of natural gas to determine a site-specific emissions standard for the operating period. For example, the NSPS emissions rate for a large base load combustion turbine burning 100 percent distillate oil during the 12-operaitng month period would be 1,070 lb CO_2/MWh-gross.[399]

To determine what emission rates are currently achieved by existing high-efficiency combined cycle EGUs and simple cycle EGUs, the EPA reviewed 12-operating-month generation and CO_2 emissions data from 2015 through 2021 for all combined and simple cycle EGUs that submitted continuous emissions monitoring system (CEMS) data to the EPA's emissions collection and monitoring plan system (ECMPS). The data were sorted by the lowest

[399] The heat input-based emission standards of natural gas and distillate oil are 117 and 163 lb CO_2/MMBtu, respectively. The ratio of the heat input emission rates (1.39) is multiplied by the natural gas-fired emissions rate (770 lb CO_2/MWh) to get the applicable emissions rate (1,070 lb CO_2/MWh).

maximum 12-operating-month emissions rate for each unit to identify long-term emission rates on a lb CO_2/MWh-gross basis that have been demonstrated by the existing combined cycle and simple cycle EGU fleets. Since an NSPS is a never-to-exceed standard, the EPA is proposing that use of long-term data are more appropriate than shorter term data in determining an achievable standard. These long-term averages account for degradation and variable operating conditions, and the EGUs should be able to maintain their current emission rates, as long as the units are properly maintained. While annual emission rates indicate a particular standard is achievable for certain EGUs in the short term, they are not necessarily representative of emission rates that can be maintained over an extended period using highly efficient generating technology in combination with best operating and maintenance practices.

To determine the 12-operating-month average emissions rate that is achievable by application of the BSER, the EPA calculated 12-month CO_2 emission rates by dividing the sum of the CO_2 emissions by the sum of the gross electrical energy output over the same period. The EPA did this separately for combined cycle EGUs and simple cycle EGUs to determine the emissions rate for the base load and intermediate load subcategories, respectively.

For base load combustion turbines, the EPA evaluated three emission rates: 730, 770, and 800 lb CO_2/MWh-gross. An emissions rate of 730 lb CO_2/MWh-gross has been demonstrated by a single combined cycle facility—the Okeechobee Clean Energy Center. This facility is a large 3-on-1 combined cycle EGU that commenced operation in 2019 and uses a recirculating cooling tower for the steam cycle. Each turbine is rated at 380 MW and the three HRSGs feed a single steam turbine of 550 MW. The EPA is not proposing to use the emissions rate of this EGU to determine the standard of performance, for multiple reasons. The Okeechobee Clean Energy Center uses a 3-on-1 multi-shaft configuration but, many combined cycle EGUs use a 1-on-1 configuration. Combined cycle EGUs using a 1-on-1 configuration can be designed such that both the combustion turbine and steam turbine are arranged on one shaft and drive the same generator. This configuration has potential capital cost and maintenance costs savings and a smaller plant footprint that can be particularly important for combustion turbines enclosed in a building. In addition, a single shaft configuration has higher net efficiencies when operated at part load than a multi-shaft configuration. Basing the emissions standard on the performance of multi-shaft combined cycle EGUs could limit the ability of owners/operators to construct new combined cycle EGUs in space-constrained areas (typically urban areas[400]) and combined cycle EGUs with the best performance when operated as intermediate load EGUs.[401] Either of these outcomes could result in greater overall emissions from the power sector. An advantage of multi-shaft (2-on-1 and 3-on-1) configurations is that the turbine engine can be installed initially and run as a simple cycle EGU, with the HRSG and steam turbines added at a later date, all of which allows for more flexibility for the regulated community. In addition, a single large steam turbine can generate electricity more efficiently than multiple smaller steam turbines, increasing the overall efficiency of comparably sized combined cycle EGUs. According to Gas Turbine World 2021, multi-shaft combined cycle EGUs have design efficiencies that are 0.7 percent higher than single shaft combined cycle EGUs using the same turbine engine.[402]

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[400] Generating electricity closer to electricity demand can reduce stress on the electric grid, reducing line losses and freeing up transmission capacity to support additional generation from intermittent renewable sources. Further, combined cycle EGUs located in urban areas could be designed as CHP EGUs, which have potential environmental and economic benefits.

[401] Power sector modeling projects that combined cycle EGUs will operate at lower capacity factors in the future. Combined cycle EGUs with lower base load efficiencies, but higher part load efficiencies could have lower overall emission rates.

[402] According to the data in Gas Turbine World 2021, while there is a design efficiency advantage of going from a 1-on-1 configuration to a 2-on-1 configuration (assuming the same turbine engine) there is no efficiency advantage of 3-on-1 configurations compared to 2-on-1 configurations.

The efficiency of the Rankine cycle (*i.e.*, HRSG plus the steam turbine) is determined in part by the ability to cool the working fluid (*e.g.*, steam) after it has been expanded through the turbine. All else equal, the lower the temperature that can be achieved, the more efficient the Rankine cycle. The Okeechobee Clean Energy Center used a recirculating cooling system, which can achieve lower temperatures than EGUs using dry cooling systems and therefore would be more efficient and have a lower emissions rate. However dry cooling systems have lower water requirements and therefore could be the preferred technology in arid regions or in areas where water requirements could have significant ecological impacts. Therefore, the EPA proposes that the efficient generation standard for base load EGUs should account for the use of dry cooling.

Finally, the Okeechobee Clean Energy Center is a relatively new EGU and full efficiency degradation might not be accounted for in the emissions analysis. Therefore, the EPA is not proposing that an emissions rate of 730 lb CO_2/MWh-gross is an appropriate nationwide standard. However, the EPA is soliciting comment on whether the use of alternate working fluid, such as supercritical CO_2, or other potential efficiency improvements would make this emissions rate an appropriate emissions standard for base load combustion turbines.

An emissions rate of 770 lb CO_2/MWh-gross has been demonstrated by 14 percent of recently constructed combined cycle EGUs. These turbines include combined cycle EGUs using 1-on-1 configurations and dry cooling, are manufactured by multiple companies, and have long-term emissions data that fully account for potential degradation in efficiency. One of the best performing large combined cycle EGUs that has maintained an emissions rate of 770 lb CO_2/MWh-gross is the Dresden plant, located in Ohio.[403] This 2-on-1 combined cycle facility,

[403] The Dresden Energy Facility is listed as being located in Muskingum county, Ohio, as being owned by the Appalachian Power Company, as having commenced commercial operation in late 2011. The facility ID (ORISPL) is 55350 1A and 1B.

uses a recirculating cooling tower, and has maintained an emissions rate of 765 lb CO_2/MWh-gross, measured over 12 operating months with 99 percent confidence. The turbine engines are rated at 2,250 MMBtu/h, which demonstrates that the standard of 770 lb CO_2/MWh-gross is achievable at a heat input rating of 2,000 MMBtu/h. In addition, while a 2-on-1 configuration and a cooling tower are more efficient than a 1-on-1 configuration and dry cooling, the Dresden Energy Facility does not use the most efficient combined cycle design currently available. Multiple more efficient designs have been developed since the Dresden Energy Facility commenced operation a decade ago that more than offset these efficiency losses. Therefore, the EPA proposes that while the Dresden combined cycle EGUs uses a 2-on-1 configuration with a cooling tower, it demonstrates that an emissions rate of 770 lb CO_2/MWh-gross is achievable for all new large combined cycle EGUs. For additional information on the EPA analysis of emission rates for high efficiency base load combined cycle EGUs, see the TSD titled *Efficient Generation at Combustion Turbine Electric Generating Units*, which is available in the rulemaking docket.

The EPA is not proposing an emissions rate of 800 lb CO_2/MWh-gross because it does not represent the most efficient combined cycle EGUs designs. Nearly half of recently constructed combined cycle EGUs have maintained an emissions rate of 800 lb CO_2/MWh-gross. However, the EPA is soliciting comment on whether this higher emissions rate is appropriate on grounds that it would increase flexibility and reduce costs to the regulated community by allowing more available designs to operate as base load combustion turbines.

With respect to small combined cycle combustion turbines, the best performing unit is the Holland Energy Park facility in Holland, Michigan, which commenced operation in 2017 and uses a 2-on-1 configuration and a cooling tower.[404] The 50 MW turbine engines have individual heat input ratings of 590 MMBtu/h and serve a single 45 MW steam turbine. The facility has maintained a 12-operating month, 99 percent confidence emissions rate of 870 lb CO_2/MWh-gross. This long-term data accounts for degradation and variable operating conditions and demonstrates that a base load combustion turbine EGU with a turbine rated at 250 MMBtu/h should be able to maintain an emissions rate of 900 lb CO_2/MWh-gross.[405] In addition, there is a commercially available HRSG that uses supercritical CO_2 instead of steam as the working fluid. This HRSG would be significantly more efficient than the HRSG that uses dual pressure steam, which is common for small combined cycle EGUs.[406] When these efficiency improvements are accounted for, a new small natural gas-fired combined cycle EGU would be able to maintain an emissions rate of 850 lb CO_2/MWh-gross. Therefore, the Agency is soliciting comment on whether the small natural gas-fired base load combustion turbine emissions standard should be 850 lb CO_2/MWh-gross.

In summary, the Agency solicits comment on the following range of potential standards of performance:

- New and reconstructed natural gas-fired base load combustion turbines with a heat input

[404] The Holland Park Energy Center is a CHP system that uses hot water in the cooling system for a snow melt system that uses a warm water piping system to heat the downtown sidewalks to clear the snow during the winter. Since this useful thermal output is low temperature, it does not materially reduce the electrical efficiency of the EGU. If the useful thermal output were accounted for, the emissions rate of the Holland Energy Park would be lower. The facility ID (ORISPL) is 59093 10 and 11.

[405] To estimate an achievable emissions rate for an efficient combined cycle EGU at 250 MMBtu/h the EPA assumed a linear relationship for combined cycle efficiency with turbine engines with base load ratings of less than 2,000 MMBtu/h.

[406] If the combustion turbine engine exhaust temperature is 500ºC or greater, a HRSG using 3 pressure steam without a reheat cycle could potentially provide an even greater increase in efficiency (relative to a HRSG using 2 pressure steam without a reheat cycle).

rating that is greater than 2,000 MMBtu/h: a range of 730–800 lb CO_2/MWh-gross;

- New and reconstructed natural gas-fired base load combustion turbines with a heat input rating of 250 MMBtu/h: a range of 850 to 900 lb CO_2/MWh-gross.

For intermediate load combustion turbines, the EPA evaluated the performance of recently constructed high efficiency natural gas-fired simple cycle EGUs. The EPA evaluated three emission rates for the intermediate load emissions standard: 1,200, 1,150, and 1,100 lb CO_2/MWh-gross. Sixty two percent of recently constructed intermediate load simple cycle EGUs have maintained an emissions rate of 1,200 lb CO_2/MWh-gross, 17 percent have maintained an emissions rate of 1,150 lb CO_2/MWh-gross, and 6 percent have maintained an emissions rate of 1,100 lb CO_2/MWh-gross. However, the units that have maintained an emissions rate of 1,100 lb CO_2/MWh-gross generally have a single large aeroderivative combustion turbine design. In contrast, the ones that have maintained an emission rate of 1,150 lb CO_2/MWh-gross have multiple different designs, including an industrial frame combustion turbine design, and are made by multiple manufacturers. Therefore, the EPA is proposing an intermediate load emissions standard of 1,150 lb CO_2/MWh-gross. The Agency is soliciting comment on whether the standard should be 1,100 lb CO_2/MWh-gross, or whether that would result in unacceptably high costs because currently only a single design for a large aeroderivative simple cycle turbine would be able to meet this standard. The Agency is also soliciting comment on a standard of performance of 1,200 lb CO_2/MWh-gross. While this would achieve fewer GHG reductions, it would increase flexibility, and potentially reduce costs, to the regulated community by allowing the currently available designs to operate as intermediate load combustion turbines. For additional information on the EPA analysis of emission rates for high efficiency intermediate load simple cycle EGUs, see the TSD *Efficient Generation at Combustion Turbine Electric*

Generating Units, which is available in the rulemaking docket.

The EPA is also soliciting comment on whether the use of steam injection is applicable to intermediate load combustion turbines. Steam injection is the use of a relatively low cost HRSG to produce steam that is injected into the combustion chamber of the combustion turbine engine instead of using a separate steam turbine. Advantages of steam injection include improved efficiency and increases the output of the combustion turbine as well as reducing NO_X emissions. Combustion turbines using steam injection have characteristics in-between simple cycle and combined cycle combustion turbines. They are more efficient, but more complex and have higher capital costs than simple cycle combustion turbines without steam injection. Combustion turbines using steam injection are simpler and have lower capital costs than combined EGUs but have lower efficiencies. The EPA is aware of a single combustion turbine that is using steam injection that has maintained a 12-operaitng month emission rates of less than 1,000 lb CO_2/MWh-gross. The EPA requests that commenters include information on whether this technology would be applicable to intermediate load combustion turbines along with cost information.

2. Phase-2 Standards

The use of CCS and hydrogen co-firing are both approaches developers are considering to reduce GHG emissions beyond highly efficient generation. However, as noted above, these approaches apply to different subcategories and are not applicable to the same EGUs. The proposed phase-2 standards are in table 3.

Table 3—Phase-2 Standards of Performance

Subcategory	BSER	Standard of Performance
Low load	Clean Fuels	120–160 lb CO_2/MMBtu
Intermediate load	Highly efficient simple cycle technology coupled with co-	1,000 lb CO_2/MWh-gross

	firing 30 percent low-GHG hydrogen	
Base load, not combusting at least 10 percent hydrogen	Highly efficient combined cycle technology coupled with 90 percent CCS	90 lb CO_2/MWh-gross
Base load, combusting at least 10 percent hydrogen	Highly efficient combined cycle technology coupled with co-firing 30 percent low-GHG hydrogen	680 lb CO_2/MWh-gross

Co-firing 30 percent by volume low-GHG hydrogen reduces emissions by 12 percent. The EPA applied this percent reduction to the emission rates for the intermediate load and base load, combusting at least 10 percent hydrogen subcategories, to determine the phase-1 standards. For the base load combustion turbines not combusting at least 10 percent hydrogen subcategory, the EPA reduced the emissions rate by 89 percent to determine the phase-1 standards.[407] The CCS percent reduction is based on a CCS system capturing 90 percent of the emitting CO_2 being operational anytime the combustion turbine is operating. However, if the carbon capture equipment has lower availability/reliability than the combustion turbine or the CCS equipment takes longer to startup than the combustion turbine itself there would be periods of operation where the CO_2 emissions would not be controlled by the carbon capture equipment. The EPA is soliciting comment on the expected availability and startup time of carbon capture equipment and if those should be accounted for in the CCS-based numeric standard of performance.

The emission standards for the intermediate and base load combustion turbines would also be adjusted based on the uncontrolled emission rates of the fuels relative to natural gas. For 100 percent distillate oil-fired combustion turbines, the emission rates would be 1,300 lb CO_2/MWh-gross, 120 lb CO_2/MWh-gross, and 910 lb CO_2/MWh-gross for the intermediate load,

[407] The 89 percent reduction from CCS accounts for the increased auxiliary load of a 90 percent post combustion amine-based capture system.

non low-GHG hydrogen co-firing base load, and low-GHG hydrogen co-firing base load subcategories respectively.

H. Reconstructed Stationary Combustion Turbines

In the previous sections, the EPA explained the background of and requirements for new and reconstructed stationary combustion turbines and evaluated various control technology configurations to determine the BSER. Because the BSER is the same for new and reconstructed stationary combustion turbines, the Agency is proposing to use the same emissions analysis for both new and reconstructed stationary combustion turbines. For each of the subcategories, the EPA is proposing that the proposed BSER results in the same standard of performance for new stationary combustion turbines and reconstructed stationary combustion turbines. Since reconstructed turbines could likely incorporate technologies to co-fire hydrogen as part of the reconstruction process at little or no cost, the low-GHG hydrogen co-firing would likely to be similar to those for newly constructed combustion turbines. For CCS, the EPA approximated the cost to add CCS to a reconstructed combustion turbine by increasing the capital costs of the carbon capture equipment by 10 percent relative to the costs for a newly constructed combustion turbine. This increases the capital cost from $949/kW to $1,044/kW.[408] Using a 12-year amortization period, 90 percent-capture amine-based post combustion CCS system increases the LCOE by $8.5/MWh and has an overall CO_2 abatement costs of $25/ton ($28/tonne).

A reconstructed stationary combustion turbine is not required to meet the standards if doing so is deemed to be "technologically and economically" infeasible.[409] This provision requires a case-by-case reconstruction determination in the light of considerations of economic

[408] The kW value used as reference for the costs is the output from the combined cycle EGU prior to the installation of the CCS.
[409] 40 CFR 60.15(b)(2).

and technological feasibility. However, this case-by-case determination would consider the identified BSER, as well as technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and of reasonable cost, depending on site-specific considerations and if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

I. Modified Stationary Combustion Turbines

CAA section 111(a)(4) defines a “modification” as “any physical change in, or change in the method of operation of, a stationary source” that either “increases the amount of any air pollutant emitted by such source or … results in the emission of any air pollutant not previously emitted.” Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e).

In the 2015 NSPS, the EPA did not finalize standards of performance for stationary combustion turbines that conduct modifications; instead, the EPA concluded that it was prudent to delay issuing standards until the Agency could gather more information (80 FR 64515; October 23, 2015). There were two several reasons for this determination: few sources had undertaken NSPS modifications in the past, the EPA had little information concerning them, and available information indicated that very few existing combustion turbines would undertake NSPS modifications in the future; and since the Agency eliminated proposed subcategories for small EGUs in the 2015 NSPS, questions were raised as to whether smaller existing combustion turbines that undertake a modification could meet the final performance standard of 1,000 lb CO_2/MWh-gross.

It continues to be the case that the EPA is aware of no evidence indicating that combustion turbines may undertake actions that could qualify as NSPS modifications in the future. Combustion turbines have unique characteristics that make determining an appropriate emission standard for modified sources a challenging task. For example, each combustion turbine engine has a specific corresponding combustor. The development of more efficient combustor upgrades for existing turbine designs typically requires manufacturers to expend considerable resources. Consequently, not all manufacturers offer combustor upgrades for smaller or older designs because it would be difficult to recoup their investment.

In addition, natural gas has the lowest CO_2 emission rate (in terms of CO_2/MMBtu) of any fossil fuel. As a result, an owner or operator that adds the ability to burn a backup fuel, such as distillate oil, to an existing turbine would likely trigger an NSPS modification. This is a relatively low-capital cost upgrade that would significantly increase a unit's potential hourly emission rate, even though the annual emissions increase would be relatively minor because operating permits generally limit the amount of distillate oil that a unit can burn. The EPA needs to conduct additional analysis to determine an appropriate emission standard for units that undertake this type of modification, which does not involve any of the combustion turbine components that impact efficiency.

To be clear, the EPA is not proposing a decision that modifications should be subject to different requirements than those being proposed for new and reconstructed sources. The EPA plans to continue to gather information, consider the options for modifications, and may develop a new proposal for modifications in the future. Therefore, the EPA is not proposing a standard of performance for combustion turbines that conduct modifications.

J. Startup, Shutdown, and Malfunction

In its 2008 decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that, the SSM exemption violates the requirement under section 302(k) of the CAA that some CAA section 112 standard apply continuously. Consistent with *Sierra Club v. EPA*, the EPA is proposing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of startup, shutdown, and malfunction and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. These general provision requirements would automatically apply to the standards set in an NSPS , unless the regulation specifically overrides these general provisions. The NSPS subpart TTTT (40 CFR part 60 subpart TTTT), does not contain an opacity standard, thus, the requirements at 40 CFR 60.11(c) are not applicable. The NSPS subpart TTTT also overrides 40 CFR 60.8(c) in table 3 and requires that sources comply with the standard(s) at all times. In reviewing NSPS subpart TTTT and proposing the new NSPS subpart TTTTa, the EPA is proposing to retain in subpart TTTTa the requirements that sources comply with the standard(s) at all times. Therefore, the EPA is proposing in table 3 of the new subpart TTTTa to override the general provisions for SSM provisions. The EPA is proposing that all standards in subpart TTTTa apply at all times.

The EPA has attempted to ensure that the general provisions we are proposing to override are inappropriate, unnecessary, or redundant in the absence of the SSM exemption. The EPA is specifically seeking comment on whether we have successfully done so.

In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained in this section of the preamble, has not proposed alternate standards for those periods. The EPA analysis of achievable emission standards used CEMS data that includes all period of operation. Since periods of startup, shutdown, and malfunction were not excluded from the analysis, the EPA is not proposing alternate standard for those periods of operation.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a "normal or usual manner" and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting "achievable" standards under CAA section 112) has been upheld as reasonable by the D.C Circuit in *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 606–610 (2016).]

K. Testing and Monitoring Requirements

Because the NSPS reflects the application of the best system of emission reduction under conditions of proper operation and maintenance, in doing the NSPS review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the NSPS. This section will include a discussion on the current testing and monitoring requirements of the NSPS and any additions the EPA is proposing to include in 40 CFR part 60, subpart TTTTa.

1. General Requirements

The current rule allows three approaches for determining compliance with its emissions limits: Continuous measurement using CO_2 CEMS and flow measurements for all EGUs; calculations using hourly heat input and 'F' factors[410] for EGUs firing uniform oil or gas or non-uniform fuels; or Tier 3 calculations using fuel use and carbon content as described in GHGRP regulations for EGUs firing non-uniform fuels. The first two approaches are in use for carbon dioxide by the Acid Rain program (40 CFR part 75), to which most, if not all, of the EGUs affected by NSPS subpart TTTT are already subject, while the last approach is in use for carbon dioxide, nitrous oxide, and methane reporting from stationary fuel combustion sources (40 CFR part 98, subpart C).

The EPA believes continuing the use of these familiar approaches already in use by other programs represents a cost-effective means of obtaining quality assured data requisite for

[410] An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.

determining carbon dioxide mass emissions. Therefore, no changes to the current ways of collecting carbon dioxide and associated data needed for mass determination, such as flow rates, fuel heat content, fuel carbon content, and the like, are proposed. Because no changes are proposed and because the cost and burden for EGU owners or operators are already accounted for by other rulemakings, this aspect of the proposed rule is designed to have minimal, if any, cost or burden associated with carbon dioxide testing and monitoring. In addition, the proposal contains no changes to measurement and testing requirements for determining electrical output, both gross and net, as well as thermal output, to current existing requirements.

However, the EPA requests comment on whether continuous carbon dioxide and flow measurements should become the sole means of compliance for this rule. Such a switch would increase costs for those EGU owners or operators who are currently relying on the oil- or gas-fired or non-uniform fuel-fired calculation-based approaches for compliance. By way of reference, the annualized cost associated with adoption and use of continuous carbon dioxide and flow measurements where none now exist is estimated to be about $52,000. To the extent that the rule were to mandate continuous carbon dioxide and flow measurements in accordance with what is currently allowed as one option and that an EGU lacked this instrumentation, its owner or operator would need to incur this annual cost to obtain such information and to keep the instrumentation calibrated.

2. Requirements for Sources Implementing CCS

The CCS process is also subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The "suppliers of carbon dioxide" source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the "geologic sequestration of carbon dioxide" source category of the GHGRP (GHGRP subpart RR). In 2022, to complement GHGRP subpart RR, the EPA proposed the "geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916" source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[411] [412] [413]

The current rule leverages the regulatory requirements under GHGRP subpart RR and does not reference GHGRP subpart VV. The EPA is proposing that any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the captured CO_2 is sent offsite, then the facility injecting the CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. This proposal does not change any of the

[411] 87 FR 36920 (June 21, 2022).
[412] International Standards Organization (ISO) standard designated as CSA Group (CSA) / American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as "CSA/ANSI ISO 27916:2019").
[413] As described in 87 FR 36920 (June 21, 2022), both subpart RR and proposed subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation. However, to verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, we are leveraging regulatory reporting requirements under the GHGRP. Further, we note that the determination that the BSER is adequately demonstrated relies on geologic sequestration that is not associated with EOR, however EGUs would have the option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. We also emphasize that this proposal does not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU assure that captured CO_2 is managed at an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the proposed rule.

3. Requirements for Sources Co-firing Low-GHG Hydrogen

Because the EPA is basing its proposed definition of low-GHG hydrogen consistent with IRC section 45V(b)(2)(D), it is reasonable, if possible and practicable, for the EPA to adopt, in whole or in part, the eligibility, monitoring, verification, and reporting protocols associated with IRC section 45V(b)(2)(D) when finalized by Treasury as applicable to demonstrations by EGUs that they are using low-GHG hydrogen. The provisions under development by Treasury are specifically designed to ensure that hydrogen that is eligible for the lowest-GHG tier of the tax credit is in fact produced consistent with that definition. Adopting very similar requirements for demonstrations by EGUs that they are using low-GHG hydrogen would help ensure there are not dueling eligibility requirements for low-GHG hydrogen production with overall emissions rates of 0.45 kg CO_2e/kg H_2 or less. Adopting similar methods for assessing GHG emissions associated with hydrogen production pathways would create clarity and certainty and reduce confusion.

The EPA is taking comment on its proposal to closely follow Treasury protocols in determining how EGUs demonstrate compliance with the fuel characteristics required in this rulemaking. The EPA is taking comment on what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to co-fire low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts, and attribute certificates. Given the complexities of tracking produced hydrogen and the public interest in such data, the EPA is also taking comment on whether EGUs should be required to make fully transparent their sources of low-GHG hydrogen and the corresponding quantities procured. The EPA is also seeking comment on requiring that EGUs using low-GHG hydrogen to demonstrate that their hydrogen is exclusively from facilities that only produce low-GHG hydrogen, as a means of reducing demonstration burden and opportunities for double counting. The EPA solicits comment on a mechanism to operationalize such a provision.

Treasury is currently developing implementing rules for IRC section 45V though an interagency process including the DOE and the EPA, which will be subject to robust public involvement. Congress specified a methodology for determining well-to-gate[414] emissions for hydrogen production projects using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model) to determine the credit tiers (45V(b)(2)(A), 45V(b)(2)(B), 45V(b)(2)(C), and 45V(b)(2)(D)) applicable for a proposed taxpayer project. Consistent with its proposal to define low-GHG hydrogen consistent with IRC section 45V(b)(2)(D), the EPA is also proposing to adopt to the maximum extent possible the same methodology specified in IRC section 45V and requirements currently under development for the purpose of demonstrating compliance with the requirement to combust low-GHG hydrogen under this NSPS. One example would be requiring that the owner/operator of the combustion turbine obtain from the hydrogen producer from which they purchase low-GHG hydrogen the hydrogen producer's calculation of GHG levels associated with its hydrogen production using the GREET well-to-gate analysis. The GREET model is well established, designed to adapt to evolving knowledge, and capable of including technological advances. Importantly, a publicly accessible on-line version will be released to enable a broad range of user access. The requirements under development in the Treasury-led interagency process include third-party verification requirements, and the EPA solicits comment on whether the EPA should consider such protocols as part of the standards required for EGUs to demonstrating compliance. Given the sequential timing of EPA and Treasury processes, the EPA may take further action, after promulgation of this NSPS, to provide additional guidance for implementation of Treasury's implementation framework in this particular context. The EPA requests comment on its proposal to adopt as much as possible the methodology specified in IRC section 45V and the

[414] The well-to-gate analysis represents a subset of the cradle to grave analysis. The energy and emission associated with the manufacturing and recycling of the hydrogen production facility and the energy facilities used to power the hydrogen production facility are not considered.

implementing requirements currently under development by Treasury as part of the obligations for EGUs to demonstrate compliance with the requirement to combust low-GHG hydrogen under this NSPS.

In addition to proposing to incorporate as much as possible Treasury's eligibility, monitoring, reporting, and verification protocols as sufficient to demonstrate compliance by the EGUs with the low-GHG hydrogen co-firing obligations, the EPA is also taking comment on several underlying policy issues relevant to ensuring that hydrogen used to comply with this rule is low-GHG hydrogen. New project eligibility for hydrogen production tax credits under IRC section 45V expires at the end of 2032. New projects must be under construction by the end of 2032 to be eligible for the 45V tax credit. Co-firing with low-GHG hydrogen under this new source performance standard proposal could be phased in at the beginning of 2035, 2 years after the IRC section 45V tax credit expires for new projects, which could potentially limit its applicability. IRS has not yet released guidance on how many years projects that begin construction before the deadline will have to be considered as still eligible for the credit. However, past IRS guidance for Section 45/48 tax credits provides 4 years for most eligible technologies, and up to 10 years for offshore wind and projects located on federal lands. Under current guidance, CCS projects have 6 years to come online after the start of construction for eligibility for 45Q. Given this and other uncertainties, the EPA is taking comment on issues that would be relevant should the Agency develop its own protocols for EGUs to demonstrate compliance with the overall emissions rate in IRC section 45V(b)(2)(D) for co-firing as BSER in this rulemaking.

The EPA is also taking comment on strategies the EPA could adopt to inform its own eligibility, monitoring, reporting and verification protocols to ensuring compliance with the 0.45

kg CO_2e/kg H_2 or less emission rate for compliance with the low-GHG provisions of this rule, if the EPA does not adopt Treasury's protocols. The purpose of these strategies would be to ensure that EGUs are using only low-GHG hydrogen, *i.e.*, hydrogen that results in GHG emissions of less than 0.45 kg CO_2 per kg H_2. The EPA is taking comment on the appropriateness of requiring EGUs to provide verification that the hydrogen they use complies with this standard, as demonstrated by the GREET model for estimating the GHG emissions associated with hydrogen production, and to what extent EGUs would be required to verify the accuracy of the inputs and conclusions of the GREET model for the hydrogen used by the EGU to comply with this rule. The EPA is soliciting comments on other models and methods and boundary conditions to develop GHG emissions estimates for qualifying low-GHG hydrogen production.

Several important considerations with respect to determining overall GHG emissions rates for hydrogen production pathways have already taken shape in the public sphere and will continue to percolate in the various Federal government fora outlined above. The EPA is soliciting comment on these issues, as they relate to co-firing low-GHG hydrogen in combustion turbines and the requisite need to only utilize the lowest-GHG hydrogen in these applications. The EPA notes this is one of multiple forthcoming opportunities for public comment on this suite of issues, and the EPA's proposal is specific to low-GHG hydrogen in the context of qualifying a co-firing fuel as part of BSER.

It is important to note that the landscape for methane emissions monitoring and mitigation is changing rapidly. For example, the EPA is in the process of developing enhanced data reporting requirements for petroleum and natural gas systems under its GHGRP, and is in the process of finalizing requirements under New Source Performance Standards and Emission Guidelines for the oil and gas sector that will result in mitigation of methane emissions. With these changes, it is expected that the quality of data to verify methane emissions will improve and methane emissions rates will change over time. Adequately identifying and accounting for overall emissions associated with methane-based feedstocks is essential in the determination of accurate overall emissions rates to comply with the low-GHG hydrogen standards in this rule. The EPA is taking comment on how methane leak rates can be appropriately quantified and conservatively estimated given the inherent uncertainties and wide range of basin-specific characteristics. The EPA is soliciting comment on whether EGUs should be required to produce a demonstration of augmented in-situ monitoring requirements to determine upstream emissions when methane feedstock is used for low-GHG hydrogen used by the EGU for compliance with this rule. The EPA is also taking comment on whether EGUs should use a default assumption for upstream methane leak rates in the event monitoring protocols are not finalized as part of this rulemaking, and what an appropriate default leak rate should be, including what evidence would be necessary for the EGU to deviate from that default assumption. The EPA is also taking comment on the appropriateness of requiring EGUs to provide CEMS data for SMR or ATR processes seeking to produce qualifying low-GHG hydrogen for co-firing to ensure the amount of carbon captured by CCS is properly and consistently monitored and outage rates and times are recorded and considered. The EPA is soliciting comment on providing EGUs with a representative and climate-protective default assumption for carbon capture rates associated with SMR and ATR hydrogen pathways, inclusive of outages, if CCS is used for low-GHG hydrogen production as part of this rulemaking, including what evidence would be necessary for the EGU to deviate from that default assumption.

In comparison with petrochemical-based hydrogen production pathways discussed above, electroyzer-based hydrogen production has the potential for lower GHG-hydrogen because the technology is based on splitting water (H_2O) molecules rather than splitting hydrocarbons (e.g., CH_4). For EGUs relying on hydrogen produced using this pathway, the EPA is seeking comment on the method for assuring that energy inputs to that production are consistent with the low-GHG hydrogen standard that EGUs would be required to meet under this rule. Specifically, the EPA is taking comment on requiring EGUs to provide substantiation of low-GHG energy inputs into any overall emissions assessment for electrolytic or SMR hydrogen production pathways for hydrogen used by the EGUs to comply with the low-GHG hydrogen standard in this rule. Energy Attribute Credits (EAC) (EAC from renewable sources are sometimes known as Renewable Energy Credits or RECs) are produced for each megawatt hour of low-GHG generation and therefore offer a measurable, auditable, and verifiable approach for determining the GHG emissions associated with the energy used to make the low-GHG hydrogen. EACs with specific attributes are commonly used in the electricity markets to substantiate corporate clean energy commitments and use, as well as for utility compliance with state RPS and CES programs. The EPA proposes requiring EGUs to provide EAC verification for low-GHG emission energy inputs into GHG emissions assessments for hydrogen used by that EGU to comply with the low-GHG standard in this rule, for all hydrogen pathways. The EPA is seeking comment on allowing EGUs to use EACs as part of the documentation required for verifying the use of low-GHG hydrogen.

The EPA is taking comment on allowing EGUs to comply with the low-GHG hydrogen standard in this rule if they demonstrate that the hydrogen used is produced from a dedicated low-GHG emitting electricity source connected to an electrolyzer, without any grid exchanges. The EPA is also taking comment on a more detailed approach for EGUs to demonstrate that purchased hydrogen meets the low-GHG standard. Many announced hydrogen production projects pair electrolyzers with renewable and nuclear energy, which are likely capable of producing low-GHG hydrogen. These renewable generation sources are variable and nuclear units go offline for refueling purposes. In these cases, and others, grid-based electricity, which often has a high carbon intensity, might be pursued in combination with EACs for each megawatt hour of grid-based energy used. Aligning the time and place (temporal and geographic alignment) of EACs used to allocate and describe delivered grid-based electricity consumed could potentially help ensure the cleanest possible hydrogen.[415] Some degree of alignment geographically, for example delivery of power to the balancing authority, could ensure that EACs used are representative of the allocation of the energy mix consumed by the electrolyzers. The EPA is seeking comment on allowing EGUs to use this type of alignment to verify that the hydrogen used by the EGU meets the low-GHG standard.

There is growing interest in hourly EAC alignment for electrolytic hydrogen, and tracking systems are evolving to meet this need in real time. To wit, PJM announced it would introduce EACs with hourly data stamping for low-GHG generators in March, 2023.[416] Hourly EAC alignment policies could provide a high level of assurance that EACs used are displacing coincident carbon intensity grid profiles. On the other hand, stakeholders have identified the potential of hourly EAC requirements creating high-cost barriers for near term electrolyzer deployment. While hourly tracking systems are coming online, they are still nascent. The EPA is taking comment on the concept of allowing EGUs to use temporal EAC alignment, for the grid-based electricity use in hydrogen production process for hydrogen used by the EGU to comply with the low-GHG hydrogen standards, including hourly, monthly, and annual alignment.

[415] "How Can Hydrogen Producers Show That They Are "Clean"?, Resources for the Future, October 27, 2022.
[416] "PJM to offer time-matched renewable energy certificates as demand for 24/7 coverage grows" Utility Dive, February 21, 2023.

L. Recordkeeping and Reporting Requirements

The current rule (subpart TTTT of 40 CFR Part 60) requires EGU owners or operators to prepare reports in accordance with the Acid Rain Program's ECMPS and, for the EGUs relying on the compliance approaches contained in Appendix G of 40 CFR part 75, with the reporting requirements of that Appendix. Such reports are to be submitted quarterly. The EPA believes all EGU owners and operators have extensive experience in using the ECMPS and use of a familiar system ensures quick and effective rollout of the program in today's proposal. Because all EGUs are expected to be covered by and included in the ECMPS, minimal, if any, costs for reporting are expected for this proposal. In the unlikely event that a specific EGU is not already covered by and included in the ECMPS, the estimated annual per unit cost would be about $8,500.

The current rule's recordkeeping requirements at 40 CFR part 60.5560 rely on a combination of general provision requirements (see 40 CFR 60.7(b) and (f)), requirements at subpart F of 40 CFR part 75, and an explicit list of items, including data and calculations; the EPA proposes to retain those existing subpart TTTT of 40 CFR Part 60 requirements in the new NSPS subpart TTTTa of 40 CFR Part 60. the annual cost of those recordkeeping requirements would be the same amount as is required for subpart TTTT of 40 CFR Part 60 recordkeeping. As the recordkeeping in subpart TTTT of 40 CFR Part 60 will be replaced by similar recordkeeping in subpart TTTTa of 40 CFR Part 60 upon promulgation, this annual cost for recordkeeping will be maintained.

M. Additional Solicitations of Comment and Proposed Requirements

This section includes additional issues the Agency is specifically soliciting comment on. It also provides a summary of some of the key considerations the EPA is soliciting comment on with respect to the proposed CAA section 111(b) requirements.

1. CCS as the Sole BSER for the Base Load Subcategory

As described above, the EPA is proposing to establish two standards for the base load subcategory: a standard for combustion turbines that combust at least 10 percent hydrogen and that is based on co-firing 30 percent by volume low-GHG hydrogen as the BSER, and a separate standard for all other base load combustion turbines that is based on CCS as the BSER. As an alternative to this proposed approach, the EPA is soliciting comment on having a single standard for the base load subcategory which would be based only on CCS as a component of the BSER. Under this alternative, EPA would not establish a base load subcategory for combustion turbines that co-fire more than 10 percent hydrogen. This approach may achieve greater emission reductions than the EPA's proposed standards because, as the discussion above indicates, a BSER based on 90 percent post-combustion capture of GHG emissions from a base load combustion turbine would achieve significantly greater reductions in emissions than a BSER based on 30 percent co-firing with low-GHG hydrogen.

This alternative approach may also reflect the more likely uses of hydrogen as a source of fuel in new combustion turbines. The EPA has proposed a standard for base load combustion turbines that co-fire more than 10 percent hydrogen in part because the Agency understands a number of power companies are actively developing combustion turbines that are designed to co-fire hydrogen and would not find it cost-effective to implement CCS. However, the Agency recognizes that power companies may ultimately come to utilize low-GHG hydrogen as a low-GHG storage fuel reserved for intermediate load combustion turbines that support variable renewable generation, rather than for combustion turbines that generate at base load. Using low-GHG hydrogen, in the form of hydrogen produced through methods such as electrolysis powered by renewable or nuclear energy, to fuel base load generation is inefficient because of thermodynamic inefficiencies in producing the hydrogen and because the renewable or nuclear energy used to produce the hydrogen could otherwise be put into the grid. An approach in which EPA establishes a single CCS-based second phase standard of performance for base load combustion turbines, along with a second phase standard for intermediate load combustion turbines that is based on low-GHG hydrogen as a component of the BSER, would align with this potential scenario. The EPA requests comment on this alternative approach.

2. Co-firing Low-GHG Hydrogen as BSER for Intermediate Load Combined Cycle and Simple Cycle Subcategories

The EPA is also soliciting comment on subcategorizing intermediate load combustion turbines into an intermediate load combined cycle subcategory and an intermediate load simple cycle subcategory. The BSER for both subcategories would be highly efficient generation (accordingly either simple cycle technology or combined cycle technology) coupled with co-firing 30 percent low-GHG hydrogen. Dividing the intermediate load subcategory into these two subcategories would assure that intermediate load combined cycle turbines would have a more stringent standard of performance—that is, expressed in a lower lb CO_2/MWh—than intermediate load simple cycle turbines. In addition to the numeric emissions standards, owners/operators would also have to demonstrate that the intermediate load combustion turbine combusted a minimum of 30 percent low-GHG hydrogen during the 12-operating month compliance period.

3. Integrated Onsite Generation and Energy Storage

Integrated equipment is currently included as part of the affected facility and the EPA is soliciting comment on the best approach to recognizing the environmental benefits of onsite integrated non-emitting generation and energy storage. The EPA is proposing regulatory text to clarify that the output from integrated renewables is included as output when determining the NSPS emissions rate. The EPA is also proposing that the output from the integrated renewable generation is not included when determining the net electric sales for applicability purposes. In the alternative, the EPA is soliciting comment on whether instead of exempting the generation from the integrated renewables from counting toward electric sales, the potential output from the integrated renewables would be included when determining the design efficiency of the facility. Since the design efficiency is used when determining the electric sales threshold this would increase the allowable electric sales for subcategorization purposes. Including the integrated renewables when determining the design efficiency of the affected facility would have the impact of increasing the operational flexibility of owners/operators of intermediate load combustion turbines. Renewables typically have much lower 12-operating month capacity factors than the intermediate electric sales threshold so could allow the turbine engine itself to operate at a higher capacity factor while still being considered an intermediate load EGU. Conversely, if the integrated renewables operate at a 12-operating month capacity factor of greater than 20 percent that would reduce the ability of a peaking turbine engine to operate while still remaining in the low load subcategory. However, even if a combustion turbine engine itself were to operate at a capacity factor of less than 20 percent and become categorized as an intermediate load combustion turbine when the output form the integrated renewables are considered, the output from the integrated renewables could lower the emissions rate such that the affected facility would be in compliance with the intermediate load emissions standard.

For integrated energy storage technologies, the EPA is soliciting comment on including the rated output of the energy storage when determining the design efficiency of the affected facility. Similar to integrated renewables, this would increase the flexibility of owner/operators to operate at higher capacity factors while remaining in the low and intermediate load subcategories. The EPA is not proposing that the output from the energy storage be considered in either determining the NSPS emissions rate or as net electric sales for subcategorization applicability purposes. While additional energy storage will allow for integration of additional intermittent renewable generation, the energy storage devices could be charged using grid supplied electricity that is generated from other types of generation. Therefore, this is not necessarily stored low-GHG electricity.

4. Definition of System Emergency

40 CFR part 60, subpart TTTT (and the proposed 40 CFR part 60, subpart TTTTa) include a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted toward the percentage electric sales subcategorization threshold.[417] The EPA concluded that this exclusion is necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector (80 FR 64612; October 23, 2015). Some in the regulated community have informed the Agency that additional clarification on a system emergency would need tobe determined and documented for compliance purposes. The intent is that the local grid operator would determine which EGUs are essential to maintain grid reliability. The EPA is soliciting comments on amending the definition of system emergency to clarify how it would be implemented. The current text is any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely

[417] Electricity sold by units that are not called upon to operate due to a system emergency (*e.g.,* units already operating when the system emergency is declared) is counted toward the percentage electric sales threshold.

affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

5. Definition of Natural Gas

40 CFR part 60, subpart TTTT (and the proposed 40 CFR part 60, subpart TTTTa) include a definition of natural gas. Natural gas is a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value. The EPA is soliciting comment on if the exclusions for specific gases such as landfill gas, etc. are necessary of if they should be deleted. If landfill gas, coal-derived gas, or other gases are processed to meet the methane and heating value content of pipeline quality natural gas they could be mixed into the pipeline network and it is the intent that this mixture be considered natural gas for the purposes of 40 CFR part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa.

6. Additional Amendments

The EPA is proposing multiple less significant amendments. These amendments would be either strictly editorial and would not change any of the requirements of 40 CFR part 60, subpart TTTT or are intended to add additional compliance flexibility. The proposed amendments would also be incorporated into the proposed subpart TTTTa. For additional information on these amendments, see the redline strikeout version of the rule showing the proposed amendments. First, the EPA is proposing editorial amendments to define acronyms the first time they are used in the regulatory text. Second, the EPA is proposing to add International System of Units (SI) equivalent for owners/operators of stationary combustion turbines complying with a heat input-based standard. Third, the EPA is proposing to fix errors in the current 40 CFR part 60, subpart TTTT regulatory text referring to part 63 instead of part 60. Fourth, as a practical matter owners/operators of stationary combustion turbines subject to the heat input-based emissions standard need to maintain records of electric sales to demonstrate that they are not subject to the output-based emissions standard. Therefore, the EPA is proposing to add a specific requirement that owner/operators maintain records of electric sales to demonstrate they did not sell electricity above the threshold that would trigger the output-based standard. Next, the EPA is proposing to update the ANSI, ASME, and ASTM test methods to include more recent versions of the test methods. Finally, the EPA is proposing to add additional compliance flexibilities for EGUs either serving a common electric generator or using a common stack. Specifically, for EGUs serving a common electric generator, the EPA is soliciting comment on whether the Administrator should be able to approve alternate methods for determining energy output. For EGUs using a common stack, the EPA is soliciting comment on whether specific procedures should be added for apportioning the emissions and/or if the Administrator should be able to approve site-specific alternate procedures.

7. Summary of Solicitation of Comment on BSER Variations

This section summarizes the variations on the subcategories and on BSER for combustion turbines on which the EPA is soliciting comment. It is intended to highlight certain aspects of the proposal the Agency is soliciting comment on and is not intended to cover all aspects of the proposal.

For the low load subcategory, the EPA is soliciting comment on:

- An electric sales threshold of between 15 to 25 percent for all combustion turbines regardless of the specific design efficiency.
- An electric sales threshold based on three quarters of the design efficiency of the combustion turbine. This would result in electric sales thresholds of 18 to 22 percent for simple cycle turbines and 26 to 31 percent for combined cycle turbines.

For the intermediate load subcategory, the EPA is soliciting comment on:

- An efficiency-based emissions standard of between 1,000 to 1,200 lb CO_2/MWh-gross.
- The use of steam injection as part of the first BSER component.
- An electric sales threshold based on 94 percent of the design efficiency. This would result in electric sales thresholds of 29 to 35 percent for simple cycle turbines and 40 to 49 percent for combined cycle turbines.
- A hydrogen co-firing range of 30 to 50 percent as the second component of the BSER.
- Beginning implementation of the second component of the BSER (*i.e.*, hydrogen co-firing) as early as 2030.
- The second component of the BSER would establish separate subcategories for simple and combined cycle intermediate load combustion turbines, both based on co-firing low-GHG hydrogen.

For the base load subcategory, the EPA is soliciting comment on:

- An efficiency-based emissions standard of between 730 to 800 lb CO_2/MWh-gross for large combustion turbines.
- An efficiency-based emissions standard of between 850 to 900 lb CO_2/MWh-gross for small combustion turbines.
- Beginning implementation of the second component of the BSER (*i.e.*, CCS or hydrogen co-firing) as early as 2030.
- A hydrogen co-firing range of 30 to 50 percent as the second component of the BSER for combustion turbines co-firing hydrogen.
- A single BSER based on the use of CCS for all base load combustion turbines.

N. Compliance Dates

The EPA is proposing that affected sources that commenced construction or reconstruction after [**INSERT DATE OF PUBLICATION OF PUBLICATION IN THE FEDERAL REGISTER**], would need to meet the requirements of 40 CFR part 60, subpart TTTTa upon startup of the new or reconstructed affected facility or the effective date of the final rule, whichever is later. This proposed compliance schedule is consistent with the requirements in section 111 of the CAA.

VIII. Requirements for New, Modified, and Reconstructed Fossil Fuel-fired Steam Generating Units

A. Overview

As is further explained in this section, because the EPA is unaware of any coal-fired steam generating projects under development or any projections that suggest that new coal will be built in the near term in the U.S., the EPA is not proposing to review the standards of performance in NSPS TTTT with regards to new or reconstructed coal-fired units. The EPA is proposing to make slight changes to the applicability requirements of 40 CFR part 60, subpart TTTT as further explained in this section. As discussed in section V.B.2 of this preamble, on December 20, 2018, the EPA proposed amendments that would revise the determination of the BSER for control of GHG emissions from newly constructed coal-fired steam generating units in 40 CFR part 60, subpart TTTT (83 FR 65424). The EPA has not taken further action to finalize the 2018 proposed rule and intends to withdraw it in a separate notice.

B. Eight-year Review of NSPS for Fossil Fuel-fired Steam Generating Units

The EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015. As noted in section IV.C, the EPA is not aware of any plans by any companies to undertake new construction of a new fossil fuel-fired steam generating unit, or to undertake a modification or reconstruction of a fossil fuel-fired steam generating unit, that would be subject to the 2015 NSPS for steam generating units. Accordingly, the EPA does not consider it necessary to review that NSPS. See "New Source Performance Standards (NSPS) Review: Advanced notice of proposed rulemaking," 76 FR 65653, 65658 (October 24, 2011) (suggesting it may not be necessary for the EPA to review an NSPS when no new construction, modification, or reconstruction is expected in the source category).

C. Projects Under Development

Finally, during the 2015 NSPS rulemaking, the EPA identified the Plant Washington project in Georgia and the Holcomb 2 project in Kansas as EGU "projects under development" based on representations by developers that the projects had commenced construction prior to the proposal of the 2015 NSPS and, thus, would not be new sources subject to the final NSPS (80 FR 64542–43; October 23, 2015). The EPA did not set a performance standard at the time but committed to doing so if new information about the projects became available. These projects were never constructed and are no longer expected to be constructed.

The Plant Washington project was to be an 850-MW supercritical coal-fired EGU. The Environmental Protection Division (EPD) of the Georgia Department of Natural Resources issued air and water permits for the project in 2010 and issued amended permits in 2014.[418] [419] [420] In 2016, developers filed a request with the EPD to extend the construction commencement deadline specified in the amended permit, but the director of the EPD denied the request, effectively canceling the approval of the construction permit and revoking the plant's amended air quality permit.[421]

The Holcomb 2 project was intended to be a single 895-MW coal-fired EGU and received permits in 2009 (after earlier proposals sought approval for development of more than one unit). In 2020, after developers announced they would no longer pursue the Holcomb 2 expansion project, the air permits were allowed to expire, effectively canceling the project.

For these reasons, the EPA is proposing to remove these projects under the applicability exclusions in subpart TTTT.

IX. Proposed ACE Repeal

The EPA is proposing to repeal the ACE Rule. A general summary of the ACE Rule, including its regulatory and judicial history, is included in section V.B. of this preamble. The EPA proposes to repeal the ACE Rule on three grounds that together and, with respect to the first

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[418] See *https://www.gpb.org/news/2010/07/26/judge-rejects-coal-plant-permits*.
[419] See *https://www.southernenvironment.org/press-release/court-rules-ga-failed-to-set-safe-limits-on-pollutants-from-coal-plant/*.
[420] See *https://permitsearch.gaepd.org/permit.aspx?id=PDF-OP-22139*.
[421] See *https://www.southernenvironment.org/wp-content/uploads/legacy/words_docs/EPD_Plant_Washington_Denial_Letter.pdf*.

two grounds, independently, justify the rule's repeal. First, the EPA no longer believes that heat rate improvements (HRI) are the BSER for existing coal-fired EGUs. In fact, the EPA now believes that HRI are unnecessary and even counterproductive in the context of this source category because they would provide negligible CO_2 reductions overall and lead to increases in CO_2 emissions from certain designated facilities due to the rebound effect explained in section X.D.5.a. Moreover, due to changes in the industry and developments in the costs of controls, more impactful technologies like co-firing of natural gas and CCS, which the ACE Rule rejected, are now cost reasonable for designated facilities with longer operating horizons. Second, the ACE Rule was contrary to CAA section 111 and the EPA's implementing regulations because it did not identify the BSER or the "degree of emission limitation achievable" by applying the BSER with sufficient precision to provide the states with adequate guidance as to the level of emission reduction that their standards of performance must achieve in order for the EPA to approve them. Rather, the ACE Rule provided states with virtually unfettered discretion to determine how much, if any, emission reductions their standards would achieve. Third, as explained in the recently proposed revisions to the EPA's implementing regulations, the ACE Rule adopted an incorrect legal interpretation of CAA section 111 that precluded states from allowing their sources to comply with standards of performance by trading or averaging. On the contrary, CAA section 111(d) accords states with discretion to provide sources with compliance flexibilities, including trading or averaging in appropriate circumstances, as long as state plans maintain equivalent emission reductions as would be achieved if each affected source was achieving its applicable standard of performance.

A. Summary of the Key Features of the ACE Rule

The key features of the ACE Rule were that it determined that HRI was the BSER for coal-fired EGUs; it rejected several other controls, including co-firing with natural gas and CCS; and it interpreted CAA section 111 to preclude states from allowing compliance flexibilities such as trading or averaging.

The ACE Rule determined that the BSER for coal-fired EGUs was a "list of 'candidate technologies,'" consisting of seven types of the "most impactful HRI technologies, equipment upgrades, and best operating and maintenance practices," (84 FR 32536; July 8, 2019), including, among others, "Boiler Feed Pumps" and "Redesign/Replace Economizer." Id. at 32537 (table 1). The rule provided a range of improvements in heat rate that each of the seven "candidate technologies" could achieve if applied to coal-fired EGUs of different capacities. For six of the technologies, the expected level of improvement in heat rate ranged from 0.1–0.4 percent to 1.0–2.9 percent, and for the seventh technology, "Improved Operating and Maintenance (O&M) Practices," the range was "0 to >2%." Id. The ACE Rule went on to explain that states were to review each of their designated facilities, on either a source-by-source or group-of-sources basis, and "evaluate the applicability of each of the candidate technologies." Id. at 32550. Specifically, "states will use the information provided by the EPA [*i.e.*, the list of candidate technologies and each technology's range of HRI potential] as guidance but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies." Id. at 32538. The ACE Rule emphasized that states had "inherent flexibility" in undertaking this task with "a wide range of potential outcomes." Id. at 32542. The ACE Rule was clear that states could conclude that it was not appropriate to apply some of the technologies. Id. at 32550. Moreover, if a state did decide to apply a particular technology to a particular source, the state could determine the level of heat rate improvement from the technology to be anywhere within the range that the EPA had identified for that technology, or even outside that range. Id. at 32551. The ACE Rule went on to say that after the state applied the technologies and calculated the amount of HRI in this discretionary manner, it should determine the standard of performance that the source could achieve, Id. at 32550, but the state could then adjust that standard further based on the application of source-specific factors such as remaining useful life. Id. at 32551. Moreover, according to the ACE Rule, the state could combine both of those actions into a "hybridized" approach in which it determined the standard of performance in a single combined step. Id. at 32550.

The ACE Rule went on to identify the process by which states were required to take these actions. According to the rule, states must "evaluat[e] each" of the seven candidate technologies and provide a summary, which "include[s] an evaluation of the … degree of emission limitation achievable through application of the technologies." Id. at 32580. Further, the state must provide a variety of information about each power plant, including, the plant's "annual generation," "CO_2 emissions," "[f]uel use, fuel price, and carbon content," "operation and maintenance costs," "[h]eat rates," "[e]lectric generating capacity," and the "timeline for implementation," among other information. Id. at 32581. The EPA explained that the purpose of this data was to allow the Agency to "adequately and appropriately review the plan to determine whether it is satisfactory." Id. at 32558.

The ACE Rule projected that if states generally applied the set of candidate technologies to their sources, the rule would achieve a less-than-1-percent reduction in power-sector CO_2

emissions by 2030.[422] However, the rule also projected that it would result in increased CO_2 emissions from power plants in 15 states and the District of Columbia due to the rebound effect for the reasons explained in section X.D.5.a.[424]

The ACE Rule considered several other control measures as the BSER, including co-firing with natural gas and CCS, but rejected them. The ACE Rule rejected co-firing with natural gas primarily on grounds that it was too costly in general, and especially for sources that have limited or no access to natural gas. 84 FR 32545 (July 8, 2019). The rule also concluded that generating electricity by co-firing natural gas in a utility boiler would be an inefficient use of the gas when compared to combusting it in a combustion turbine. Id. The ACE Rule also rejected CCS on grounds that it was too costly. Id. at 32548. The rule identified the high capital and operating costs of CCS and noted the fact that the IRC 45Q tax credit, as it then applied, would provide only limited benefit to sources. Id. at 32548-49.

In addition, the ACE Rule interpreted CAA section 111 to preclude states from allowing their sources to trade or average to demonstrate compliance with their emission standards. Id. at 32556–57.

B. Changes in Factual and Policy Underpinnings of ACE Rule

The EPA's first basis for proposing to repeal the ACE Rule is that changes have occurred in the factual and policy underpinnings of the rule concerning the structure of the industry and CO_2 control requirements, leading the EPA to conclude that the BSER of HRI that the ACE Rule included was flawed and that other control measures qualify as the BSER instead.

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[422] ACE Rule RIA 3-11, table 3-3.
[424] The rebound effect becomes evident by comparing the results of the ACE Rule IPM runs for the 2018 reference case, EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case*, EPA-HQ-OAR-2017-0355-26720, and for the "Illustrative ACE Scenario. *IPM State-Level Emissions: Illustrative ACE Scenario*, EPA-HQ-OAR-2017-0355-26724.

In explaining its proposal to repeal the ACE Rule and replace it with this proposed rule, the EPA is following the direction of the Supreme Court in *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009). There, the Court described the type of reasoning an agency must provide to justify changing a rule it has previously adopted:

> [T]he requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it is changing position…. And of course the agency must show that there are good reasons for the new policy. But it need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates. This means that the agency need not always provide a more detailed justification than what would suffice for a new policy created on a blank slate. Sometimes it must—when, for example, its new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance interests that must be taken into account…. It would be arbitrary or capricious to ignore such matters. In such cases it is not that further justification is demanded by the mere fact of policy change; but that a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy.

Id. at 514–16 (emphasis in original; citation omitted).

Since the promulgation of the ACE Rule in 2019, the factual underpinnings of the rule have changed in several ways. The first concerns the structure of the power sector. The EPA discusses these changes in section IV of this preamble. For more than the past decade, coal-fired EGUs have experienced greater competitive pressure from natural gas-fired combustion turbines and renewable energy generating sources, and as a result, have been reducing their utilization and retiring. This trend has continued since the promulgation of the ACE Rule in 2019, with a number of sources announcing retirements. Importantly, in part because of the enactment of the IRA, which provides substantial incentives for renewable energy, more coal-fired EGUs are expected to announce retirements in the near future.

In addition to these significant changes in the structure of the power sector, the costs of two control measures, co-firing with natural gas and CCS, have fallen substantially for sources with longer-term operating horizons. As noted above, the ACE Rule rejected natural gas co-firing as the BSER on grounds that it was too costly and would lead to inefficient use of natural gas. However, as discussed in section X.D.2.b.ii of this preamble, the costs of natural gas co-firing have decreased, and the EPA is proposing that the costs of co-firing 40 percent by volume natural gas are reasonable for existing coal-fired EGUs in the medium-term subcategory, *i.e.*, units that plan to operate during, in general, the 2032 to 2040 period. In addition, natural gas is available in greater amounts, and there are fewer coal-fired EGUs, than at the time of the ACE Rule's promulgation, which mitigates the concerns in that rule about inefficient use of natural gas. See section X.D.2.b.iii.(B).

Similarly, the ACE Rule rejected CCS as the BSER on grounds that it was too costly. However, as discussed in section X.D.1.b.ii of this preamble, the costs of CCS have substantially declined, partly because of developments in the technology that have lowered capital costs, and partly because the IRA extended and increased the IRC section 45Q tax credit so that it defrays a higher portion of the costs of CCS. Accordingly, for coal-fired EGUs that will continue to operate past 2040, the EPA is proposing that the costs of CCS, which have fallen to approximately $7– $12/MWh, are reasonable.

On the other hand, the EPA now recognizes that the ACE Rule's view of HRI improvements as appropriate for the BSER for coal-fired EGUs was flawed. HRI achieve only a limited amount of GHG emission reductions. The ACE Rule projected that if states generally applied the set of candidate technologies to their sources, the rule would achieve a less-than-1-

percent reduction in power-sector CO_2 emissions by 2030.[425] Moreover, as a practical matter, as discussed in section IX.C., the ACE Rule would not necessarily achieve any reductions, and, in fact could result in at least some states establishing emission standards that allow sources to increase their emission rates. It is clear that the amount of emission reductions that the ACE Rule would achieve is minimal, which raises significant concerns that the rule's determination that HRI qualify as the BSER was flawed because one of the criteria for whether a control measure qualifies as the BSER is the amount of emission reductions that the measure achieves. Moreover, at least for a subset of sources, HRI are likely to cause a rebound effect leading to an increase in GHG emissions, for the reasons explained in section X.D.5.a. The rebound effect was quite pronounced in the ACE Rule – the rule projected that it would result in increased CO_2 emissions from power plants in 15 states and the District of Columbia.[426] In addition, as discussed in section IX.C, the BSER based on HRI as included in the ACE Rule would not necessarily achieve any reductions, and, in fact could result in at least some states establishing emission standards that allow sources to increase their emission rates. Accordingly, the EPA believes that HRI do not qualify as the BSER for any coal-fired EGUs, although they remain on the menu of improvements a state may consider to meet the proposed GHG emissions standard.

Based on the just-described developments and changes in policy, the EPA is proposing to fundamentally change its regulatory scheme for coal-fired power plants from the ACE Rule. As discussed in section X.C.3, of this preamble, the EPA is proposing to subcategorize coal-fired power plants according to the period of time that they will continue to operate. For sources in the

[425] ACE Rule RIA 3-11, table 3-3.
[426] The rebound effect becomes evident by comparing the results of the ACE Rule IPM runs for the 2018 reference case, EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case*, EPA-HQ-OAR-2017-0355-26720, and for the "Illustrative ACE Scenario. *IPM State-Level Emissions: Illustrative ACE Scenario*, EPA-HQ-OAR-2017-0355-26724.

imminent-term and near-term subcategories – which include sources that, in general, have federally enforceable commitments to permanently cease operations by 2032 or 2035, respectively – the EPA is proposing that the BSER is routine methods of operation and maintenance, with associated presumptive emission standards that do not permit an increased emission rate and are not anticipated to have a rebound effect. For sources in the medium-term subcategory – which includes sources that are not in the other subcategories and that have a federally enforceable commitment to permanently cease operations by 2040 – the EPA is proposing that the BSER is co-firing 40 percent by volume natural gas. The EPA believes that this control measure is appropriate because it achieves substantial reductions and can be implemented at reasonable cost. In addition, the EPA believes that because of the large supply of natural gas that is available, devoting part of this supply for fuel for a coal-fired steam generating unit in place of a percentage of the coal burned at the unit should not be considered an inefficient use of natural gas and will not cause any adverse impacts on the energy system. See section X.D.2.b.iii.(B). For sources in the long-term subcategory – which includes sources that do not have a federally enforceable commitment to permanently cease operations by 2040 – the EPA is proposing that the BSER is CCS with 90 percent capture of CO_2. The EPA believes that this control measure is appropriate because it achieves substantial reductions and can be implemented at reasonable cost. See section X.D.1.c.

The EPA is not proposing HRI as the BSER for any of the subcategories. As discussed in section X.D.5.a, the EPA does not consider HRI to be an appropriate BSER for the imminent-term and near-term subcategories because it would achieve relatively few, if any, emissions reductions, and, for at least a subset of sources, it could have the effect of increasing emissions through the rebound effect. The EPA is proposing to reject HRI as the BSER for the medium-term and long-term subcategories because HRI could also lead to a rebound effect for them, and, most importantly, changed circumstances now indicate that because co-firing natural gas and CCS, respectively, are available, can be implemented at reasonable cost, and will achieve more GHG emissions reductions.

For these reasons, the EPA proposes to repeal the ACE Rule and to replace it with the emission guidelines proposed in this action.

C. Insufficiently Precise BSER and Degree of Emission Limitation

The second reason why the EPA is proposing to repeal the ACE Rule is that the rule did not identify the BSER or the degree of emission limitation achievable through the application of the BSER with sufficient precision to provide adequate guidance to the states as to the level of emission reduction that the standards of performance must achieve. The ACE Rule determined the BSER to be a menu of HRI "candidate technologies," but did not identify a meaningful degree of emission limitation and, further, authorized the states wide latitude to decide which, if any, candidate technologies to apply and what amount of heat rate improvement, if any, to achieve. As a result, the ACE Rule was contrary to CAA section 111 and the implementing regulations, and, in any event, a poor policy guide for states in developing their state plans, and by which the EPA could determine whether those state plans were satisfactory.

CAA section 111 and the EPA's long-standing implementing regulations establish a step-by-step process for the EPA and states to regulate emissions of certain air pollutants from existing sources. First, the EPA determines the BSER and calculates the degree of emission limitation achievable by application of the BSER. The EPA promulgates this information as part of the emission guidelines, CAA section 111(d)(1), (a)(1), 40 CFR 60.22, 60.22a; this information constitutes the necessary basis for determining the emission reductions that state plans must achieve in order to comport with CAA section 111. The Supreme Court has confirmed that the EPA is responsible for determining both the BSER and the associated degree of emission limitation. *West Virginia v. EPA*, 142 S. Ct. 2587, 2607 (2022).

Once the EPA makes these determinations, the state must establish "standards of performance" for its sources that are based on the degree of emission limitation that the EPA determines in the emissions guidelines. CAA section 111(a)(1) makes this clear through its definition of the term "standard of performance:" "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER]." The state includes the standards of performance in its state plan and submits it to the EPA for review. CAA section 111(d)(2)(A).

The EPA approves the plan, including the standards of performance, if they are "satisfactory," under CAA section 111(d)(2)(A). EPA's long-standing implementing regulations make clear that the EPA's basis for determining whether the plan is "satisfactory" includes that the plan must contain "emission standards . . . no less stringent than the corresponding emission guideline(s)." 40 CFR 60.24(c). The EPA's revised implementing regulations contain the same requirement. 40 CFR 60.24a(c). In adopting the implementing regulations, the EPA explained that if its review of state plans were based "solely on procedural criteria," then "states could set extremely lenient standards . . . so long as EPA's procedural requirements were met." 40 FR 53343 (November 17, 1975). It should be noted that in applying the standards to any particular source, the state may take into consideration, among other factors, the remaining useful life of the source, CAA section 111(d)(1) (RULOF provision), as discussed in section XI.D.2.

In the ACE Rule, the EPA recognized that it has the responsibility to determine the BSER and the degree of emission limitation achievable through application of the BSER. 84 FR 32537

(July 8, 2019). However, the rule was flawed because it did not in fact make those determinations. Rather, what the rule described as the BSER, which was the list of "candidate technologies," and what the rule described as the degree of emission limitation achievable by application of the BSER, which was the ranges of HRI calculated for the technologies, did not identify either the BSER or the associated degree of emission limitation with sufficient precision. Instead, the rule shifted the responsibility for those determinations to the states. Accordingly, the ACE Rule did not meet the CAA section 111 or regulatory requirements to determine the BSER or the degree of emission limitation.

As described above, the ACE Rule identified the HRI in the form of a list of seven "candidate technologies," accompanied by a broad wide range of percentage improvements to heat rate that these technologies could provide. Indeed, for one of them, improved O&M practices, the range was "0 to >2%", which is effectively unbounded. 84 FR 32537 (table 1). The ACE Rule was clear that this list was simply the starting point for the state to use in calculating the standards of performance for its sources and that the state had significant discretion in doing so. That is, the seven sets of technologies were "candidate[s]" that the state could, but was not required to, apply and if the state did choose to apply one or more of them, the state could do so in a manner that yielded any percentage of heat rate improvement within the range that the EPA identified, or even outside that range, if the state chose. Thus, as a practical matter, the ACE Rule did not determine either the BSER or any degree of emission limitation; both those were up to the state. In this manner, the ACE Rule in effect transferred the EPA's responsibilities to the state, directing each state to determine for its sources what the BSER would be (that is, which HRI technologies should be applied to the source and with what intensity), and, based on that, what the degree of emission limitation achievable by application of the BSER should be. See 84 FR 32537-38 (July 8, 2019).

The only constraints that the ACE Rule imposed on the states were procedural ones, and those did not give the EPA any benchmark for how to determine whether a plan could be approved or give the states any certainty to know whether their plan would be approved. As noted above, when the state submitted its plan, it needed to show that it evaluated each candidate technology for each source or group of sources, explain how it determined the degree of emission limitation achievable, and include data about the sources. However, because the ACE Rule did not include a degree of emission limitation that the standards must reflect, and instead placed the responsibility on the states to determine that amount by deciding which “candidate technologies” the source could apply to improve its performance and by how much, the EPA had no benchmark against which to judge a state’s submission to determine whether it is “satisfactory” under CAA section 111(d)(2)(A). The procedural requirements that the ACE Rule imposed on the states were not sufficient for this purpose. As the EPA stated when it adopted its implementing regulations in 1975, it is “essential” that “EPA review … [state] plans for their substantive adequacy.” 40 FR 53342-43 (November 17, 1975). The EPA rejected limiting its review based “solely on procedural criteria” because “states could set extremely lenient standards . . . so long as EPA’s procedural requirements were met.” Id. at 53343.

A draft partial state plan to implement the ACE Rule submitted by West Virginia highlights both the state’s discretion to determine what the ACE Rule described as the BSER and associated degree of emission limitation and the risks that, absent minimum requirements for emission reductions, the states could set lenient standards. The D.C. Circuit vacated the ACE Rule before any state plans were required to be submitted or had been formally submitted, but

West Virginia did release a draft of a partial state plan prior to the vacatur. The draft partial plan would have applied to one source, the Longview Power, LLC facility, and would have established a standard of performance, based on the state's consideration of the "candidate technologies," that was higher (*i.e.*, less stringent) than the source's historical emission rate. Thus, the draft plan did not achieve any emission reductions from the source, and instead would have allowed the source to increase its emissions.[427]

Finally, it should be noted that the ACE Rule's approach to determining the BSER and degree of emission limitation was a significant departure from prior emission guidelines under CAA section 111(d), in which the EPA included a numeric degree of emission limitation. See, *e.g.*, 42 FR 55796, 55797 (October 18, 1977) (limiting emission rate of acid mist from sulfuric acid plants to 0.25 grams per kilogram of acid); 44 FR 29828, 29829 (May 22, 1979) (limiting concentrations of total reduced sulfur from most of the subcategories of kraft pulp mills, such as digester systems and lime kilns, to 5, 20, or 25 ppm over 12-hour averages); 61 FR 9905, 9919 (March 12, 1996) (limiting concentration of non-methane organic compounds from solid waste landfills to 20 parts per million by volume or 98-percent reduction).

For these reasons, the EPA proposes to repeal the ACE Rule. Its failure to determine a BSER and associated degree of emission limitation were contrary to CAA section 111 and the implementing regulations. In any event, those failures were poor policy because the ACE Rule failed to set a benchmark that would guide the states in developing their state plans, and by which the EPA could determine whether those state plans were satisfactory.

[427] West Virginia CAA §111(d) Partial Plan for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs), *https://dep.wv.gov/daq/publicnoticeandcomment/Documents/Proposed%20WV%20ACE%20State%20Partial%20Plan.pdf*, accessed January 23, 2023.

D. ACE Rule's Preclusion of Emissions Trading or Averaging

While not an independent basis for repeal, the EPA also now disagrees with the ACE Rule's interpretation of CAA section 111(d) to preclude states from allowing emissions trading or averaging among their sources. It is paradoxical that in the area where Congress left matters to states' discretion—how to implement and enforce the standards set forth in the EPA's emission guidelines—the ACE Rule incorrectly interpreted the statute as constraining states' discretion. That is, CAA section 111(d) accords states discretion in developing a plan that determines the emission reduction obligations of its sources, including allowing compliance flexibilities like trading or averaging in appropriate circumstances, as long as the plan achieves equivalent emissions reductions to the EPA's emission guidelines. The ACE Rule's legal interpretation that CAA section 111(d) precludes the state from adopting those flexibilities was incorrect.

Under CAA section 111(d)(1), each state is required to submit to the EPA "a plan which … establishes standards of performance for any existing source" that emits certain types of air pollutants, and which "provides for the implementation and enforcement of such standards of performance." Under CAA section 111(a)(1), a "standard of performance" is defined as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER]."

The ACE Rule interpreted these provisions to preclude states from allowing their sources to trade or average to demonstrate compliance with their standards of performance. 84 FR 32556–57 (July 8, 2019). The ACE Rule based this interpretation on its view that CAA section 111 limits the type of "system" that the EPA may select as the BSER to a control measure that could be applied inside the fenceline of each source to reduce emissions at each source. Id. at 32523–24. The ACE Rule also concluded that the compliance measures the states include in their plans must “correspond with the approach used to set the standard in the first place,” and therefore must also be limited to inside-the-fenceline measures that reduce the emissions of each source. Id. at 32556.

The EPA has proposed to determine that the ACE Rule’s legal interpretation was incorrect in its recently published notice of proposed rulemaking to amend the CAA section 111(d) implementing regulations, “Implementing Regulations under 40 CFR Part 60 Subpart Ba Adoption and Submittal of State Plans for Designated Facilities: Proposed Rule,” 87 FR 79176, 79207 (December 23, 2022). As discussed in that notice, CAA section 111(d)(1) provides, in relevant part, that states “establish[],” “implement[],” and “enforce[]” “standards of performance for any existing source.” No provision in CAA section 111(d), by its terms, precludes states from having flexibility in determining which measures will best achieve compliance with the EPA’s emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion. As the U.S. Supreme Court has explained, CAA section 111(d) “envisions extensive cooperation between federal and state authorities, generally permitting each State to take the first cut at determining how best to achieve EPA emissions standards within its domain.” *American Elec. Power Co. v. Connecticut*, 564 U.S. 410, 428 (2011) (citations omitted). It should also be noted, however, that the flexibility that CAA section 111(d) grants to states in adopting measures for their state plans is not unfettered. The EPA may preclude certain flexibilities in specific emission guidelines where necessary to ensure that state plans achieve equivalent emission reductions to what the EPA determined is achievable through application of the BSER. Additionally, CAA section 111(d)(2) requires the EPA to review state plans to assure that they are “satisfactory.”

For the reasons just noted, the EPA proposed to disagree with the ACE Rule's conclusion that state plan compliance measures must always correspond with the approach the EPA uses to determine the BSER, so long as the plan meets the requirements of CAA section 111(d) and its implementing regulations, including the requirement that the state plan (taking into account its compliance measures) achieves equivalent emissions reductions to EPA's emission guidelines. See 87 FR 79208 (December 23, 2022). The EPA's proposed legal interpretation that CAA section 111(d) does not preclude emissions trading is consistent with the D.C. Circuit's decision in *American Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021). There, the court vacated the ACE Rule, including invalidating the rule's preclusion of emissions trading in state plans, on the basis of the reasoning that the EPA explains above. Id. at 957-58. As noted in section V.B.6, the U.S. Supreme Court reversed the D.C. Circuit's vacatur of the ACE Rule's embedded repeal of the CPP in *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), but the Court did not rule on the scope of the states' compliance flexibilities and declined to address whether CAA section 111 limits the type of "system" the EPA could consider as the BSER to inside-the-fenceline measures. See id. at 2615.

For these reasons, in its notice of proposed rulemaking to amend the CAA section 111(d) implementing regulations, the EPA proposed to interpret CAA section 111(d) as authorizing the EPA to approve state plans, in particular emission guidelines, that achieve the requisite emission limitation through the aggregate reductions from their sources, including through trading or averaging, where appropriate for a particular emission guideline and consistent with the intended environmental outcomes of the guideline. As discussed in section XI.E.2., the EPA is soliciting comment on whether trading and averaging would be an appropriate compliance mechanism for the proposed emission guideline for coal-fired steam generating units and if so, how such compliance mechanisms could be implemented to ensure equivalency with the emission reductions that would be achieved if each affected source was achieving its appliable standard of performance.

The ACE Rule's flawed legal interpretation that CAA section 111(d) precludes states from emissions trading is incorrect, and adds to EPA's reasoning for proposing to repeal the rule.

X. Proposed Regulatory Approach for Existing Fossil Fuel-fired Steam Generating Units

A. Overview

In this section of the preamble, the EPA explains the basis for its proposed emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units for states' use in plan development. This includes proposing different subcategories of designated facilities, the BSER for each subcategory, and the degree of emission limitation achievable by application of each proposed BSER. In this action, the EPA is not proposing BSER for existing electric utility natural gas-fired combustion turbines, including simple cycle and combined cycle units. However, as detailed in section XII of this preamble, the EPA is soliciting comment on possible BSER for those units, to inform future regulatory action for those units.

The proposed subcategories, the BSER for each subcategory, and the associated degrees of emission limitation are summarized in table 4, below. In brief, the EPA is proposing subcategories for steam generating units based on the type and amount of fossil fuel (*i.e.,* coal, oil, and natural gas) fired in the unit. In addition, the EPA is proposing to divide the subcategory for coal-fired units into additional subcategories based on operating horizon (*i.e.*, the period of time that sources expect to continue to operate) and, for one of those subcategories, load levels (*i.e.*, annual capacity factor). Further, the EPA is proposing to divide subcategories for oil- and natural gas-fired units based on capacity and, in some cases, geographic location.

For coal-fired steam generating units, as noted in section IV of this preamble, ongoing trends in the power sector are leading the owners or operators of many of these units to decrease utilization of their steam generating units and to announce or develop plans for retiring the units. In the course of the EPA's engagement with stakeholders to inform this proposed rule, industry stakeholders recommended that the EPA define subcategories and evaluate GHG control technology options that take these plans for ceasing operation into account. These additional subcategories are responsive to this industry input, and appropriately recognize that the GHG control technology options available to existing coal-fired steam generating units – and the cost-effectiveness of those options – differ depending on the sources' expected operating time horizon.

Table 4—Summary of Proposed BSER, Subcategories, and Degrees of Emission Limitation for Affected EGUs

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance[428]	Ranges in Values on Which the EPA is Soliciting Comment
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not adopted a federally enforceable commitment to permanently cease operations by January 1, 2040	CCS with 90 percent capture of CO_2	88.4 percent reduction in emission rate (lb CO_2/MWh-gross)	88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline	The achievable capture rate from 90 to 95 percent and the achievable degree of emission limitation defined by a reduction in emission rate from 75 to 90 percent

[428] Presumptive standards of performance are discussed in detail in section XI of the preamble as setting standards of performance are the obligation for states, not the EPA, in plan development. Inclusion in this table is for completeness.

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance [428]	Ranges in Values on Which the EPA is Soliciting Comment
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that choose to adopt a federally enforceable commitment to permanently cease operations after December 31, 2031, and before January 1, 2040, and that are not near-term units	Natural gas co-firing at 40 percent of the heat input to the unit	A 16 percent reduction in emission rate (lb CO_2/MWh-gross)	A 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline	The percent of natural gas co-firing from 30 to 50 percent and the degree of emission limitation from 12 to 20 percent

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance[428]	Ranges in Values on Which the EPA is Soliciting Comment
Near-term existing coal-fired steam generating units	Coal-fired steam generating units that choose to adopt a federally enforceable commitment to permanently cease operations after December 31, 2031, and before January 1, 2035, and to operate with annual capacity factors less than 20 percent	Routine methods of operation	No increase in emission rate (lb CO_2/MWh-gross)	An emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline	The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance[428]	Ranges in Values on Which the EPA is Soliciting Comment
Imminent-term existing coal-fired steam generating units	Coal-fired steam generating units that choose to adopt a federally enforceable commitment to permanently cease operations before January 1, 2032	Routine methods of operation	No increase in emission rate (lb CO_2/MWh-gross)	An emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline	The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline
Base load continental existing oil-fired steam generating units	Oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent	Routine methods of operation and maintenance	No increase in emission rate (lb CO_2/MWh-gross)	An annual emission rate limit of 1,300 lb CO_2/MWh-gross	The threshold between intermediate and base load from 40 to 50 percent annual capacity factor; the degree of emission limitation from 1,250 lb CO_2/MWh-gross to 1,800 lb CO_2/MWh-gross

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance [428]	Ranges in Values on Which the EPA is Soliciting Comment
Intermediate load continental existing oil-fired steam generating units	Oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent	Routine methods of operation and maintenance	No increase in emission rate (lb CO_2/MWh-gross)	An annual emission rate limit of 1,500 lb CO_2/MWh-gross	The degree of emission limitation from 1,400 lb CO_2/MWh-gross to 2,000 lb CO_2/MWh-gross
Low load (continental and non-continental) existing oil-fired steam generating units	Oil-fired steam generating units with an annual capacity factor less than 8 percent	None proposed	-	-	The threshold between low and intermediate load from 5 to 20 percent annual capacity factor
Intermediate and base load non-continental existing oil-fired steam generating units	Non-continental oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent	Routine methods of operation and maintenance	No increase in emission rate (lb CO_2/MWh-gross)	An emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline	The presumptive standard: 0 to 2 standard deviations in annual emission rate above or 0 to 10 percent above the unit-specific baseline

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance[428]	Ranges in Values on Which the EPA is Soliciting Comment
Base load existing natural gas-fired steam generating units	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent	Routine methods of operation and maintenance	No increase in emission rate (lb CO_2/MWh-gross)	An annual emission rate limit of 1,300 lb CO_2/MWh-gross	The threshold between intermediate and base load from 40 to 50 percent annual capacity factor; The acceptable standard from 1,250 lb CO_2/MWh-gross to 1,400 lb CO_2/MWh-gross
Intermediate load existing natural gas-fired steam generating units	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent	Routine methods of operation and maintenance	No increase in emission rate (lb CO_2/MWh-gross)	An annual emission rate limit of 1,500 lb CO_2/MWh-gross	The acceptable standard from 1,400 lb CO_2/MWh-gross to 1,600 lb CO_2/MWh-gross

Affected EGUs	Subcategory Definition	BSER	Degree of Emission Limitation	Presumptively Approvable Standard of Performance[428]	Ranges in Values on Which the EPA is Soliciting Comment
Low load existing natural gas-fired steam generating units	Natural gas-fired steam generating units with an annual capacity factor less than 8 percent	None proposed	-	-	The threshold between low and intermediate load from 5 to 20 percent annual capacity factor

The EPA is proposing CCS with 90 percent capture as BSER for long-term existing coal-fired steam generating units. The EPA is soliciting comment on a range of maximum capture rates (90 to 95 percent or greater) and, to potentially account for the amount of time the capture equipment operates relative to operation of the steam generating unit, a slightly lower achievable degree of emission limitation (75 to 90 percent reduction in average annual emission rate, defined in terms of pounds of CO_2 per unit of generation). As it does with all coal-fired units, the EPA calculates the proposed presumptive standards of performance for long-term units by applying the degree of emission limitation to a source-specific baseline.

Although CCS satisfies the BSER criteria for long-term coal-fired units, the EPA recognizes that many owners of existing coal-fired units have already announced plans to cease operating these units over the near- to medium-term or may soon choose to do so. For units that are planning to cease operations earlier than 2040, the cost effectiveness of CCS is likely to be less favorable in light of the capital investment required to retrofit with such systems and the relatively shorter operating period over which these units can recover costs and utilize available tax incentives for CCS. Accordingly, the EPA has determined that for units that will permanently cease operations before 2040, other GHG control options—including standards reflecting the application of natural gas co-firing or, for units that are retiring in the near term, routine operations and maintenance—achieve meaningful emission limitations and better satisfy the BSER criteria. Based on input provided by coal-fired unit owners and other stakeholders, the EPA believes that recognizing distinct BSER and corresponding emission limitations for units that will permanently cease operations over the imminent- to medium-term will also better align with industry trends and the business plans of many power companies.

Accordingly, the EPA is proposing to establish additional subcategories of existing coal-fired steam generating units based on operating timeframe, with a separate BSER and degree of emission limitation corresponding to each subcategory. For medium-term coal-fired steam generating units, the EPA is proposing natural gas co-firing at 40 percent of annual heat input as BSER because it achieves meaningful emission reductions and satisfies the other BSER criteria, including being cost reasonable for units on an intermediate operating timeframe. The EPA is soliciting comment on the percent of natural gas co-firing from 30 to 50 percent and the degree of emission limitation defined by a reduction in emission rate from 12 to 20 percent. For imminent-term and near-term coal-fired steam generating units, the EPA is proposing a BSER of routine methods of operation and maintenance. Because of differences in performance between units, the EPA is proposing to determine the associated degree of emission limitation as no increase in emission rate.

For natural gas- and oil-fired steam generating units, the EPA is proposing a BSER of routine methods of operation and maintenance and degrees of emission limitation of no increase in emission rate. However, because natural gas- and oil-fired steam generating units with similar annual capacity factors perform similarly to one another, the EPA is proposing presumptive standards of performance of 1,300 lb CO_2/MWh-gross for base load units (*i.e.*, those with annual capacity factors greater than 45 percent) and 1,500 lb CO_2/MWh-gross for intermediate load units (*i.e.*, those with annual capacity factors between 8 and 45 percent). Because natural gas- and oil-fired steam generating units with low load have large variations in emission rate, the EPA is not proposing BSER or degrees of emission limitation for those units in this action. However, the EPA is soliciting comment on a potential BSER of "clean fuels" and degree of emission limitation defined on a heat input basis by 120 to 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units and 150 to 170 lb CO_2/MMBtu for low load oil-fired steam generating units. Also, because non-continental oil-fired steam generating units operate at intermediate and base load, and because there are relatively few of those units for which to define a limit on a fleet-wide basis, the EPA is proposing degrees of emission limitation for those units of no increase in emission rate and presumptive standards based on unit-specific emission rates, as detailed in section XI of this preamble. The EPA is soliciting comment on ranges of annual capacity factors to define the thresholds between the load levels and ranges in the degrees of emission limitation, as specified in section X.E of this preamble.

The remainder of this section is organized into the following subsections. Subsection B describes the proposed applicability requirements for existing steam generating units. Subsection C provides the explanation for the proposed subcategories. Subsection D contains, for coal-fired steam generating units, a summary of the systems considered for the BSER, detailed discussion of the systems and other options considered, and explanation and justification for the determination of BSER and degree of emission limitation. Subsection E contains, for natural gas- and oil-fired steam generating units, a summary of the systems considered for the BSER, detailed discussion of the systems and other options considered, and explanation and justification for the determination of BSER and degree of emission limitation.

B. Applicability Requirements for Existing Fossil Fuel-fired Steam Generating Units

For the emission guidelines, the EPA is proposing that a designated facility[429] is any fossil fuel-fired electric utility steam generating unit (*i.e.,* utility boiler) that: (1) was in operation or had commenced construction on or before January 8, 2014;[430] (2) serves a generator capable of selling greater than 25 MW to a utility power distribution system; and (3) has a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). Consistent with the implementing regulations, the term "designated facility" is used throughout this preamble to refer to the sources affected by these emission guidelines.[431] For this action, consistent with prior CAA section 111 rulemakings concerning EGUs, the term "designated facility" refers to a single EGU that is affected by these emission guidelines. The rationale for this proposal concerning applicability is the same as that for 40 CFR part 60, subpart TTTT (80 FR 64543–44; October 23, 2015). We incorporate that discussion by reference here.

Section 111(a)(6) of the CAA defines an "existing source" as "any stationary source other than a new source." Therefore, the emission guidelines would not apply to any EGUs that are new after January 8, 2014, or modified or reconstructed after June 18, 2014, the applicability

[429] The term "designated facility" means "any existing facility…which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility. See 40 CFR 60.21a(b).
[430] Under CAA section 111, the determination of whether a source is a new source or an existing source (and thus potentially a designated facility) is based on the date that the EPA proposes to establish standards of performance for new sources.
[431] The EPA recognizes, however, that the word "facility" is often understood colloquially to refer to a single power plant, which may have one or more EGUs co-located within the plant's boundaries.

dates of 40 CFR part 60, subpart TTTT. In addition, the EPA is proposing to include in the applicability of the emission guidelines the same exemptions as discussed for 40 CFR part 60, subpart TTTT in section VII.E.1 of this preamble. Designated EGUs that may be excluded from a state's plan are: (1) units that are subject to 40 CFR part 60, subpart TTTT, as a result of commencing a qualifying modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh; (3) non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (5) units that serve a generator along with other steam generating unit(s), where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less; (6) municipal waste combustor units subject to 40 CFR part 60, subpart Eb; (7) commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or (8) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU. The EPA solicits comment on the proposed definition of "designated facility" and applicability exemptions for fossil fuel-fired steam generating units.

The exemptions listed above at (4), (5), (6), and (7) are among the current exemptions at 40 CFR 60.5509(b), as discussed in section VII.E.1 of this preamble. The exemptions listed above at (2), (3), and (8) are exemptions the EPA is proposing to revise for 40 CFR part 60, subpart TTTT, and the rationale for proposing the exemptions is in section VII.E.1 of this preamble. For consistency with the applicability requirements in 40 CFR part 60, subpart TTTT, we are proposing these same exemptions for the applicability of the emission guidelines.

The EPA is proposing to apply the same requirements to fossil fuel-fired steam generating units in non-continental areas (*i.e.*, Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA is proposing for comparable units in the contiguous 48 states. However, units in non-continental and non-contiguous areas operate on small, isolated electric grids, may operate differently from units in the contiguous 48 states, and may have limited access to certain components of the proposed BSER due to their uniquely isolated geography or infrastructure. Therefore, the EPA is soliciting comment on the proposed BSER and degrees of emission limitation for units in non-continental and non-contiguous areas, and the EPA is soliciting comment on whether those units in non-continental and non-contiguous areas should be subject to different, if any, requirements.

C. Subcategorization of Fossil Fuel-fired Steam Generating Units

Steam generating units can have a broad range of technical and operational differences. Based on these differences, they may be subcategorized, and different BSER and degrees of emission limitation may be applicable to different subcategories. Subcategorizing allows for determining the most appropriate control requirements for a given class of steam generating unit. Therefore, the EPA is proposing subcategories for steam generating units based on fossil fuel type, operating horizon and load level, and is proposing different BSER and degrees of emission limitation for those different subcategories. The EPA notes that, in section XI.B of this preamble, comment is solicited on the compliance deadline (*i.e.*, January 1, 2030), for imminent-term and near-term coal-fired steam generating units, and different subcategories of natural gas- and oil-fired steam generating units.

1. Subcategorization by Fossil Fuel Type

In the 2015 NSPS, the EPA promulgated GHG standards of performance for all new fossil fuel-fired steam generating units. 40 CFR 60.5509(a). Accordingly, existing fossil fuel-fired steam generating units are subject to regulation for GHG emissions under CAA section 111(d). In this action, the EPA is proposing definitions for subcategories of existing fossil fuel-fired steam generating units based on the type and amount of fossil fuel used in the unit. The subcategory definitions proposed for these emission guidelines are based on the definitions in 40 CFR part 63, subpart UUUUU, and using the fossil fuel definitions in 40 CFR part 60, subpart TTTT.

A coal-fired steam generating unit is an electric utility steam generating unit or IGCC unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to the proposed compliance deadline (*i.e.*, January 1, 2030), or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029.

An oil-fired steam generating unit is an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to the proposed compliance deadline (*i.e.*, January 1, 2030), or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

A natural gas-fired steam generating unit is an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired or oil-fired steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to the proposed compliance deadline (*i.e.*, January 1, 2030), or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

2. Subcategorization of Natural Gas- and Oil-fired Steam Generating Units by Load Level

The EPA is also proposing additional subcategories for oil-fired and natural gas-fired steam generating units, based on load levels: "low" load, defined by annual capacity factors less than 8 percent; "intermediate" load, defined by annual capacity factors greater than or equal to 8 percent and less than 45 percent; and "base" load, defined by annual capacity factors greater than or equal to 45 percent. In addition, the EPA is soliciting comment on a range from 5 to 20 percent to define the threshold value between low and intermediate load and a range from 40 to 50 percent to define the threshold value between intermediate and base load. The rationale for the proposed load thresholds is detailed in the description of the BSER for oil- and natural gas-fired steam generating units in section X.E of this preamble.

3. Subcategorization of Coal-fired Steam Generating Units by Operating Horizon and Load Level

As discussed in section IV of this preamble, the electric power sector is undergoing a period of significant change, with increases in the deployment of natural gas and renewable sources of electricity and decreases in the utilization of steam generating units. Many fossil fuel-fired steam generating units have plans to cease operations, are part of utilities with commitments to net zero power by certain dates, or are in states or localities with commitments to net zero power by certain dates. Over one-third of existing coal-fired steam generating capacity has planned to cease operation by 2032, and approximately half of the capacity has planned to cease operations by 2040.[432] Certain technologies that are cost reasonable for EGUs that intend to operate for the long term are less cost reasonable for EGUs with shorter operating horizons because of shorter amortization periods and, for CCS, less time to utilize the IRC section 45Q tax credit. To accommodate this reality, and to limit unnecessary investment in facilities with shorter remaining operating periods, the EPA is proposing four subcategories for steam generating units by operating horizon (*i.e.*, federally enforceable[433] commitments to permanently cease operations) and, in one case, by load level (*i.e.*, annual capacity factor) as well. “Imminent-term” steam generating units are those that choose to adopt federally enforceable commitments to permanently cease operations prior to January 1, 2032. “Near-term” steam generating units are those that choose to adopt federally enforceable commitments to permanently cease operations on or after January 1, 2032, and prior to January 1, 2035, and have federally enforceable annual capacity factor limits that are less than 20 percent. “Medium-term” steam generating units are those that choose to adopt federally enforceable commitments to permanently cease operations prior to January 1, 2040, and that are not imminent-term or near-

[432] See the *Power Sector Trends* TSD.
[433] Dates for permanently ceasing operation and capacity factor commitments that a state relies on to subcategorize coal-fired EGUs under these emission guidelines will become federally enforceable upon EPA approval of a state plan including those commitments. While such commitments must be enforceable by the state when a state plan is submitted to the EPA, they do not necessarily have to be federally enforceable at that time. However, this preamble uses the term “federally enforceable commitment” throughout to ensure there is no confusion that date and capacity factor commitments contained in a state plan will become federally enforceable upon EPA approval of that plan.

term units. "Long-term" steam generating units are those that have not adopted federally enforceable commitments to permanently cease operations prior to January 1, 2040. Details regarding the implementation of subcategories in state plans are available in section XI.D of this preamble.

The EPA is proposing the imminent-term subcategory based on a 2-year operating horizon from the proposed compliance deadline (January 1, 2030, see section XI.B for additional details). This proposed subcategory is designed to accommodate units with operating horizons short enough that no additional CO_2 control measures would be cost reasonable. The EPA is proposing the near-term subcategory to provide an alternative option for units that intend to operate for a slightly longer horizon but as peaking units, *i.e.*, that intend to run at lower load levels. The load level of 20 percent for the near-term subcategory is based on spreading an average 2 years of generation (*i.e.*, 50 percent in each year, a typical load level) that would occur under the imminent-term subcategory over the 5-year operating horizon of the near-term subcategory.

The EPA is proposing the 10-year operating horizon (*i.e.*, January 1, 2040) as the threshold between medium-term and long-term subcategories because about half of the existing steam generating unit capacity has planned operation after that date. Additionally, long-term units will have a longer amortization period and may be better able to fully utilize the IRC section 45Q tax credit. The EPA is soliciting comment on the dates and load levels used to define the coal-fired subcategories. As noted in section X.D.1.a.ii.(C) of this preamble, the costs for CCS may be reasonable for units with amortization periods as short as 8 years. Therefore, the EPA is specifically soliciting comment on an operating horizon of between 8 and 10 years (*i.e.*, January 1, 2038, to January 1, 2040) to define the date for the threshold between medium-term and long-term coal-fired steam generating units.

4. Legal Basis for Subcategorization

As noted in section V of this preamble, the EPA has broad authority under CAA section 111(d) to identify subcategories. As also noted in section V, the EPA's authority to "distinguish among classes, types, and sizes within categories," as provided under CAA section 111(b)(2) and as we interpret CAA section 111(d) to provide as well, generally allows the Agency to place types of sources into subcategories when they have characteristics that are relevant to the controls that the EPA may determine to be the BSER for those sources. One element of the BSER is cost reasonableness. See CAA section 111(d)(1) (requiring the EPA, in setting the BSER, to "tak[e] into account the cost of achieving such reduction"). As noted in section V, the EPA's long-standing regulations under CAA section 111(d) explicitly recognize that subcategorizing may be appropriate for sources based on the "costs of control."[434] Subcategorizing on the basis of federally enforceable dates for permanently ceasing operation is consistent with a central characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements: A large percentage of the industry has announced, or is expected to announce, dates for ceasing operation, and the fact that many coal-fired steam generating units intend to cease operation affects what controls are "best" for different subcategories. Whether the costs of control are reasonable depends in part on the period of time over which the affected sources can amortize those costs. Sources that have shorter

[434] 40 CFR 60.22(b)(5), 60.22a(b)(5).

operating horizons will have less time to amortize capital costs and the controls will thereby be less cost-effective and therefore may not qualify as the BSER.[435]

In addition, subcategorizing by length of period of continued operation is similar to two other bases for subcategorization on which the EPA has relied in prior rules, each of which implicates the cost reasonableness of controls: The first is load level, noted in section X.C of this preamble. For example, in the 2015 NSPS, the EPA divided new natural gas-fired combustion turbines into the subcategories of base load and non-base load. 80 FR 64510, 64602 (table 15) (October 23, 2015). The EPA did so because the control technologies that were "best"-including consideration of feasibility and cost-reasonableness—depended on how much the unit operated. The load level, which relates to the amount of product produced on a yearly or other basis, bears similarity to a limit on a period of continued operation, which concerns the amount of time remaining to produce the product. In both cases, certain technologies may not be cost reasonable because of the capacity to produce product—*i.e.*, because the costs are spread over less product produced.

The second is fuel type, as also noted in section X.C of this preamble. The 2015 NSPS provides an example of this type of subcategorization as well. There, the EPA divided new combustion turbines into subcategories on the basis of type of fuel combusted. *Id.* Subcategorizing on the basis of the type of fuel combusted may be appropriate when different controls have different costs, depending on the type of fuel, so that the cost-reasonableness of the control depends on the type of fuel. In that way, it is similar to subcategorizing by operating horizon because in both cases, the subcategory is based upon the cost reasonableness of controls.

[435] Steam Electric Reconsideration Rule, 85 FR 64650, 64679 (October 13, 2020) (distinguishes between EGUs retiring before 2028 and EGUs remaining in operation after that time).

Subcategorizing by fuel type presents an additional analogy to the present case of subcategorizing on the basis of the length of time when the source will continue to operate because this timeframe is tantamount to the length of time when the source will continue to combust the fuel. Subcategorizing on this basis may be appropriate when different controls for a particular fuel have different costs, depending on the length of time when the fuel will continue to be combusted, so that the cost-reasonableness of controls depends on that timeframe. Some prior EPA rules for coal-fired sources have made explicit the link between length of time for continued operation and type of fuel combusted by codifying federally enforceable retirement dates as the dates by which the source must "cease burning coal."[436]

D. Determination of BSER for Coal-fired Steam Generating Units

The EPA evaluated two primary control technologies as potentially representing the BSER for existing coal-fired steam generating units: CCS and natural gas co-firing. This section of the preamble discusses each of these alternatives, based on the criteria described in section V.C of this preamble.

The EPA is proposing CCS with 90 percent capture as BSER for long-term coal-fired steam generating units, that is, ones that are expected to continue to operate past 2039, because CCS can achieve an appropriate amount of emission reductions and satisfies the other BSER criteria. Because CCS is less cost reasonable for EGUs that do not plan to operate in the long term, the EPA is proposing other measures as BSER for the other subcategories of existing coal-fired steam generating units.

[436] See 79 FR 5031, 5192 (January 30, 2014) (explaining that , "[t]he construction permit issued by Wyoming requires Naughton Unit 3 to *cease burning coal* by December 31, 2017 and to be retrofitted to natural gas as its fuel source by June 30, 2018" (emphasis added)).

Specifically, for medium-term units, that is, ones that choose to adopt federally enforceable commitments to permanently cease operations after December 31, 2031, and before January 1, 2040, and are not near-term units, the EPA is proposing a BSER of 40 percent natural gas co-firing on a heat input basis. However, the EPA is taking comment on the date that defines the threshold between medium-term and long-term coal-fired steam generating units, and it is possible that the costs of CCS may be considered reasonable for some portion of the units that may be covered by the medium-term subcategory as proposed.

For imminent-term and near-term units, that is, ones that choose to adopt federally enforceable commitments to permanently cease operations before January 1, 2032, and between December 31, 2031, and January 1, 2035, coupled with an annual capacity factor limit, respectively, the EPA is proposing a BSER of routine methods of operation and maintenance that maintain current emission rates.

1. Long-term Coal-fired Steam Generating Units

In this section of the preamble, the EPA evaluates CCS and natural gas co-firing as potential BSER for long-term coal-fired steam generating units.

The EPA is proposing CCS with 90 percent capture of CO_2 at the stack as BSER for long-term coal-fired steam generating units. The Agency is taking comment on the range of the amount of capture of CO_2 from 90 to 95 percent or greater. CCS achieves substantial reductions in emissions and can capture and permanently sequester more than 90 percent of CO_2 emitted by coal-fired steam generating units. The technology is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources, and there are vast sequestration opportunities across the continental U.S. Additionally, accounting for the tax credit under IRC section 45Q, the costs for CCS are reasonable. Moreover, the non-air quality health and environmental impacts and energy requirements of CCS are not unreasonably adverse. These factors provide the basis for proposing CCS as BSER for these sources. In addition, determining CCS as the BSER promotes this useful control technology.

The EPA also evaluated natural gas co-firing at 40 percent of heat input as a potential BSER for long-term coal-fired steam generating units. While the unit level emission rate reductions of 16 percent achieved by 40 percent natural gas co-firing are reasonable, those reductions are less than CCS with 90 percent capture of CO_2. Therefore, because CCS achieves more reductions at the unit level and is cost reasonable, the EPA is not proposing natural gas co-firing as the BSER for these units.

a. CCS

In this section of the preamble, the EPA evaluates the use of CCS as the BSER for existing long-term coal-fired steam generating units. This section incorporates by reference the parts of section VII.F.3.b.iii of this preamble that discuss the aspects of CCS that are common to new combustion turbines and existing steam generating units. This section also discusses additional aspects of CCS that are relevant for existing steam generating units and, in particular, long-term units.

i. Adequately Demonstrated

The EPA is proposing that CCS is technically feasible and has been adequately demonstrated, based on the utilization of the technology at existing coal-fired steam generating units and industrial sources in addition to combustion turbines. While the EPA would propose that CCS is adequately demonstrated on those bases alone, this determination is further corroborated by EPAct05-assisted projects.

The fundamental CCS technology has been in existence for decades, and the industry has extensive experience with and knowledge about it. Thus, the EPA will explain how existing and planned fossil fuel-fired electric power plants and other industrial projects that have installed or expect to install some or all of the components of CCS technology support the EPA's proposed determination that CCS is adequately demonstrated for existing coal-fired power plants, and the EPA will explain how EPAct05-assisted projects support that proposed determination, consistent with the legal interpretation of the EPAct05 in section VII.F.3.b.iii.(A).

(A) CO_2 Capture Technology

The technology of CO_2 capture, in general, is detailed in section VII.F.3.b.iii of this preamble. As noted there, solvent-based (*i.e.*, amine-based) post-combustion CO_2 capture is the technology that is most applicable at existing coal-fired steam generating units. Technology considerations specific to existing coal-fired steam generating units, including energy demands, non-GHG emissions, and water use and siting, are discussed in section X.D.1.a.iii of this preamble. As detailed in section VII.F.3.b.iii.(A) of this preamble, the CO_2 capture component of CCS has been demonstrated at existing coal-fired steam generating units, industrial processes, and existing combustion turbines. In particular, SaskPower's Boundary Dam Unit 3 has demonstrated capture rates of 90 percent of the CO_2 in flue gas using solvent-based post-combustion capture retrofitted to existing coal-fired steam generating units. While the EPA would propose that the CO_2 capture component of CCS is adequately demonstrated on the basis of Boundary Dam Unit 3 alone, CO_2 capture has been further demonstrated at other coal-fired steam generating units (CO_2 capture from slipstreams of AES's Warrior Run and Shady Point) and industrial processes (*e.g.*, Quest CO_2 capture project), detailed descriptions of which are provided in section VII.F.3.b.iii.(A)2 of this preamble. The core technology of CO_2 capture applied to combustion turbines is similar to that of coal-fired steam generating units (*i.e.*, both may use amine solvent-based methods); therefore the demonstration of CO_2 capture at combustion turbines (*e.g.*, the Bellingham, Massachusetts, combined cycle unit), as detailed in section VII.F.3.b.iii.(A)3 of this preamble, provide additional support for the adequate demonstration of CO_2 capture for coal-fired steam generating units. Finally, EPAct05-assisted CO_2 capture projects (*e.g.*, Petra Nova) further corroborate the adequate demonstration of CO_2 capture.

(B) CO_2 Transport

As discussed in section VII.F.3.b.iii of this preamble, CO_2 pipelines are available and their network is expanding in the U.S., and the safety of existing and new CO_2 pipelines is comprehensively regulated by PHMSA. Other modes of CO_2 transportation also exist.

Based on data from DOE/NETL studies of storage resources, 77 percent of existing coal-fired steam generating units that have planned operation during or after 2030 are within 80 km (50 miles) of potential saline sequestration sites, and another 5 percent are within 100 km (62 miles) of potential sequestration sites.[437] Additionally, of the coal-fired steam generating units with planned operation during or after 2030, 90 percent are located within 100 km of one or more types of sequestration formations, including deep saline, unmineable coal seams, and oil and gas reservoirs. This distance is consistent with the distances referenced in studies that form the basis for transport cost estimates in this proposal.[438]

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[437] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details please see Chapter 6 of the IPM documentation available at: *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf*.

[438] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

(C) Geologic Sequestration of CO_2

Geologic sequestration (*i.e.*, the long-term containment of a CO_2 stream in subsurface geologic formations) is well proven and broadly available throughout the U.S. Geologic sequestration is based on a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. As discussed in section VIII.F.3.a.iii of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC Class VI well regulations, which are under the authority of SDWA, and the GHGRP, under the authority of the CAA.

Geologic sequestration potential for CO_2 is widespread and available throughout the U.S. Through an availability analysis of sequestration potential in the U.S. based on resources from the DOE, the USGS, and the EPA, the EPA found that there are 43 states with access to, or are within 100 km from, onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs.

Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies.[439] These data show that of the coal-fired steam generating units with planned operation during or after 2030, 60 percent are located within the boundary of a saline reservoir, 77 percent are located within 40 miles (80 km) of the boundary of a saline reservoir, and 82 percent are located within 62 miles (100 km) of a saline reservoir. Additionally, of the coal-fired steam generating units with planned operation during or after 2030, 90 percent are located within 100 km of any of

[439] For details, please see Chapter 6 of the IPM documentation, available at: *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf*.

the considered formations, including deep saline, unmineable coal seams, and oil and gas reservoirs.[440]

ii. Costs

The EPA has analyzed the costs of CCS for existing coal-fired long-term sources, including costs for CO_2 capture, transport, and sequestration. The EPA is proposing that this analysis demonstrates that the costs of CCS for these sources are reasonable.

The EPA assessed costs of CCS for a reference unit as well as the average cost for the fleet of coal-fired steam generating units with planned operation during or after 2030. The reference unit, which represents an average unit in the fleet, has a 400 MW-gross nameplate capacity and a 10,000 Btu/kWh heat rate. Applying CCS to the reference unit with a 12-year amortization period and assuming a 50 percent annual capacity factor—a typical value for the fleet—results in annualized total costs that can be expressed as an abatement cost of $14/ton of CO_2 reduced and an incremental cost of electricity of $12/MWh. For the fleet of coal-fired steam generating units with planned operation during or after 2030, and assuming a 12-year amortization period and 50 percent annual capacity factor, the average total costs of CCS are $8/ton of CO_2 reduced and $7/MWh. Included in these estimates is the EPA's assessment that the transport and storage costs are roughly $30/ton, on average. for the reference unit. These total costs also account for the IRC section 45Q tax credit, a detailed discussion of which is provided in section VII.F.3.b.iii.(B)3 of this preamble. Compared to the representative costs of controls for other pollutants (*i.e.*, wet FGD SO_2 emission control costs of $15.00 to $18.50/MWh as detailed in section VII.F.3.b.iii.(B)5 of this preamble), the costs for CCS on long-term coal-fired steam

[440] The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline.

generating units are anticipated to be similar or better on an incremental cost of electricity ($/MWh) basis. Therefore, the EPA is proposing that for the purposes of the BSER analysis, CCS is cost reasonable for long-term coal-fired steam generating units. The EPA also evaluated costs of CCS under various other assumptions of amortization period and annual capacity factor. Finally, it is noted that these CCS costs are lower than those in prior rulemakings due to the IRC section 45Q tax credit and reductions in the cost of the technology.

(A) CO_2 Capture Costs at Existing Coal-fired Steam Generating Units

A variety of sources provide information for the cost of CCS systems, and they generally agree around a range of cost. The EPA has relied heavily on information recently developed by NETL, in the U.S. Department of Energy, in particular, "Cost and Performance Baseline for Fossil Energy Plants,"[441] and the "Pulverized Coal Carbon Capture Retrofit Database."[442] In addition, the EPA developed an independent engineering cost assessment for CCS retrofits, with support from Sargent and Lundy.[443]

(B) CO_2 Transport and Sequestration Costs

As discussed in section VII.F.3.b.iii. of this preamble, NETL's "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies" is one of the more comprehensive sources of information on CO_2 transport and storage costs available. The Quality Guidelines provide an estimation of transport costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and

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[441] Available at *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.*

[442] Available at *https://netl.doe.gov/energy-analysis/details?id=69db8281-593f-4b2e-ac68-061b17574fb8*.

[443] Detailed cost information, assessment of technology options, and demonstration of cost reasonableness can be found in the *GHG Mitigation Measures – 111(d)* TSD.

operations and maintenance costs.[444] These Quality Guidelines also provide an estimate of sequestration costs reflecting the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection.

NETL's Quality Guidelines model costs for a given cumulative storage potential. At a storage potential of 25 gigatons of CO_2, costs range between $7.54/ton ($8.32/metric ton) sequestered (in the Illinois Basin) and $18.00/ton ($19.84/metric ton) sequestered (in the Powder River Basin).[445]

(C) Amortization Period and Annual Capacity Factor

In the EPA's cost analysis for long-term coal-fired steam generating units, the EPA assumes a 12-year amortization period and a 50 percent annual capacity factor. The 12-year amortization period is consistent with the period of time during which the IRC section 45Q tax credit can be claimed and the 50 percent annual capacity factor is consistent with the historical fleet average. However, increases in utilization are likely to occur for units that apply CCS due to the incentives provided by the IRC section 45Q tax credit. Therefore, the EPA also assessed the costs for CCS retrofitted to existing coal-fired steam generating units assuming a 70 percent annual capacity factor. For a 70 percent annual capacity factor and a 12-year amortization period, the costs for the reference unit are -$8/ton of CO_2 reduced and -$7/MWh. For either capacity factor assumption, the $/MWh costs are comparable to or less than the representative cost of installing and operating wet FGD, costs for which are detailed in VII.F.3.b.iii.(B)5.

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[444] Grant, T., *et al.* "Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies." National Energy Technology Laboratory. 2019. Available online at: *https://www.netl.doe.gov/energy-analysis/details?id=3743*.
[445] *Ibid.*

As noted in section X.C.3 of this preamble, the EPA is also taking comment on the date for the threshold between medium-term and long-term coal-fired steam generating units. For a 70 percent annual capacity factor and an 8-year amortization period, costs for the reference unit are \$24/ton of CO_2 reduced and \$21/MWh, and it is possible that the cost of generation may be reasonable relative to the representative cost for wet FGD. However, CCS will be less cost favorable for units with shorter amortization periods. For a 70 percent annual capacity factor and a 7-year amortization period, costs for the reference unit are \$34/ton of CO_2 reduced and \$21/MWh. Additional details of the cost analysis are available in the *GHG Mitigation Measures – 111(d)* TSD.

(D) Comparison to Costs for CCS in Prior Rulemakings

In the CPP and ACE Rule, the EPA determined that CCS did not qualify as the BSER due to cost considerations. Two key developments have led the EPA to reevaluate this conclusion: the costs of CCS technology have fallen and, most importantly, the extension and increase in the IRC section 45Q tax credit, as included in the IRA, in effect provide a significant stream of revenue for sequestered CO_2 emissions. The CPP and ACE Rule relied on a 2015 NETL report estimating the cost of CCS. NETL has issued updated reports to incorporate the latest information available, most recently in 2022, which show cost reductions. The 2015 report estimated incremental levelized cost of CCS at a new pulverized coal facility relative to a new facility without CCS at \$74/MWh (2022\$),[446] while the 2022 report estimated incremental

[446] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 3 (July 2015), available at: *https://netl.doe.gov/projects/files/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGastoElectRev3_070615.pdf*.

levelized cost at $44/MWh (2022$).[447] Additionally, the IRA increased the IRC section 45Q tax credit from $50/metric ton to $85/metric ton (and, in the case of EOR or certain industrial uses, from $35/metric ton to $60/metric ton), assuming prevailing wage and apprenticeship conditions are met. The IRA also enhanced the realized value of the tax credit through the direct pay and transferability monetization options described in Section IV.E.1The combination of lower costs and higher tax credits significantly improves the cost effectiveness of CCS for purposes of determining whether it qualifies as the BSER.

iii. Non-air Quality Health and Environmental Impact and Energy Requirements

CCS for steam generating units is not expected to have unreasonable adverse consequences related to non-air quality health and environmental impacts or energy requirements. As discussed later in the preamble, the EPA has considered non-GHG emissions impacts, the water use impacts, the transport and sequestration of captured CO_2, and energy requirements resulting from CCS. Because the non-air quality health and environmental impacts are closely related to the energy requirements, the latter are discussed first.

(A) Energy Requirements

For a steam generating unit with 90 percent amine-based CO_2 capture, parasitic/auxiliary energy demand increases and the net power output decreases. Amine-based CO_2 capture is an energy-intensive process. In particular, the solvent regeneration process requires substantial amounts of heat in the form of steam and CO_2 compression requires a large amount of electricity. Heat and power for the CO_2 capture equipment can be provided either by using the steam and

[447] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022), available at: *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf*.

electricity produced by the steam generating unit or by an auxiliary cogeneration unit. However, any auxiliary source of heat and power is part of the "designated facility," along with the steam generating unit. The standards of performance apply to the designated facility. Thus, any CO_2 emissions from the connected auxiliary equipment need to be captured or they will increase the facility's emission rate.

Using integrated heat and steam can reduce the capacity (*i.e.,* the amount of electricity that a unit can distribute to the grid) of a 550 MW-net coal-fired steam generating unit without CCS to 425 MW-net with CCS and contributes to a reduction in net efficiency of 23 percent.[448] Despite decreases in efficiency, IRC section 45Q tax credits provide an incentive for increased utilization. because the credits are proportional to the amount of captured and sequestered CO_2 emissions and not to the amount of electricity generated. The Agency is proposing that the energy penalty is relatively minor compared to the GHG benefits of CCS and, therefore, does not disqualify CCS as being considered the BSER for existing coal-fired steam generating units.

Additionally, the EPA considered the impacts on the power sector, on a nationwide and long-term basis, of determining CCS to be the BSER for long-term coal-fired steam generating units. The EPA is proposing that designating CCS as the BSER for existing long-term coal-fired steam generating units would have limited and non-adverse impacts on the long-term structure of the power sector. Absent the requirements defined in this action, the EPA projects that 9 GW of coal-fired steam generating units would apply CCS by 2030 and 35 GW of coal-fired steam generating units, some without controls, would remain in operation in 2040. Designating CCS to be the BSER for existing long-term coal-fired steam generating units would likely result in more

[448] DOE/NETL-2016/1796. "Eliminating the Derate of Carbon Capture Retrofits." May 31, 2016. Accessed at *https://www.netl.doe.gov/energy-analysis/details?id=d335ce79-84ee-4a0b-a27b-c1a64edbb866*.

of the coal-fired steam generating unit capacity applying CCS. The time available before the compliance deadline of January 1, 2030, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired steam generating units. While the IRC 45Q tax credit is available, long-term coal-fired steam generating units are anticipated to run at base load conditions. Total generation from coal-fired steam generating units in the other subcategories would gradually decrease over an extended period of time through 2039, subject to the commitments those units have chosen to adopt. Any decreases in the amount of generation from coal-fired steam generating units, whether locally or more broadly, are compensated for by increased generation from other sources. Additionally, for the long-term units applying CCS, the EPA is proposing the increase in the annualized cost of generation for those units is reasonable. Therefore, the EPA is proposing that there would be no unreasonable impacts on the reliability of electricity generation. A broader discussion of reliability impacts of the proposed actions is available in section XIV.F of this preamble. Finally, changes in the amount of generation from coal-fired steam generating units may contribute to additional generation from combined cycle combustion turbines. Since these EGUs have lower GHG and criteria pollutant emission rates than existing coal-fired steam generating units, overall emissions from the power sector would likely decrease.

(B) Non-GHG Emissions

For amine-based CO_2 capture retrofits to coal-fired steam generating units, decreased efficiency and increased utilization would otherwise result in increases of non-GHG emissions; however, importantly, most of those impacts would be mitigated by the flue gas conditioning required by the CO_2 capture process and by other control equipment that the units already have or may need to install to meet other CAA requirements. Decreases in efficiency result in increases in the relative amount of coal combusted per amount of electricity generated and would otherwise result in increases in the amount of non-GHG pollutants emitted per amount of electricity generated. Additionally, increased utilization would otherwise result in increases in total non-GHG emissions. However, substantial flue gas conditioning, particularly to remove SO_2, is critical to limiting solvent degradation and maintaining reliable operation of the capture plant. To achieve the necessary limits on SO_2 levels in the flue gas for the capture process, steam generating units will need to add an FGD column, if they do not already have one, and may need an additional polishing column (*i.e.,* quencher). A wet FGD column and a polishing column will also reduce the emission rate of particulate matter. Additional improvements in particulate matter removal may also be necessary to reduce the fouling of other components of the capture process (*e.g.*, heat exchangers or bag houses). NO_X emissions can cause solvent degradation and nitrosamine formation by chemical absorption of NO_X, depending on the chemical structure of the solvent. A conventional multistage water or acid wash and mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.*, nitrosamine) emissions.[449] [450] NO_X levels of the flue gas required to avoid solvent degradation and nitrosamine formation in the CO_2 scrubber vary. For most units, the requisite limits on NO_X levels to assure that the CO_2 capture process functions properly may be met by the existing NO_X combustion controls, and those units may not need to install SCR for process purposes. However, most existing coal-fired steam generating units either already have SCR or will be

[449] Sharma, S., Azzi, M., "A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies," *Fuel*, 121, 178 (2014).
[450] Mertens, J., *et al.*, "Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests," *Int'l J. of GHG Control*, 13, 72 (2013).

covered by proposed Federal Implementation Plan (FIP) requirements regulating interstate transport of NO_X (as an ozone precursors) from EGUs. See 87 FR 20036 (April 6, 2022). For units not otherwise required to have SCR, increased utilization from a CO_2 capture retrofit could result in increased emissions that may trigger New Source Review (NSR) permitting requirements and, in turn, may require the installation of SCR for those units. See section XIII.A of this preamble.

(C) Water Use and Siting

Water consumption at the plant increases when applying carbon capture, due to solvent water makeup and cooling demand. Water consumption can increase by 36 percent on a gross basis.[451] A separate cooling water system dedicated to a CO_2 capture plant may be necessary. However, the amount of water consumption depends on the design of the capture system. For example, the cooling system cited in the CCS feasibility study for SaskPower's Shand Power station would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption.[452] Regions with limited water supply may rely on dry or hybrid cooling systems, although, in areas with adequate water, wet cooling systems can be more effective.

With respect to siting considerations, CO_2 capture systems have a sizeable physical footprint and a consequent land-use requirement. The EPA is proposing that the water use and siting requirements are manageable and therefore the EPA does not expect any of these

[451] DOE/NETL-2016/1796. "Eliminating the Derate of Carbon Capture Retrofits." May 31, 2016. Accessed at *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9*.
[452] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. Accessed at *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf*.

considerations to preclude coal-fired power plants generally from being able to install and operate CCS. However, the EPA is soliciting comment on these issues.

(D) Transport and Geologic Sequestration

As noted in section VII.F.3.b.iii of this preamble, PHMSA oversight of CO_2 pipeline safety protects against environmental release during transport and UIC Class VI regulations under the SDWA, in tandem with GHGRP subpart RR requirements, ensure the protection of USDWs and the security of geologic sequestration.

iv. Extent of Reductions in CO_2 Emissions

CCS can be applied to coal-fired steam generating units at the source and reduce the CO_2 emission rate by 90 percent or more. Increased steam and power demand have a small impact on the reduction in emission rate that occurs with 90 percent capture. According to the 2016 NETL Retrofit report, 90 percent capture will result in emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture.[453] After capture, CO_2 can be transported and securely sequestered.[454] Although steam generating units with CO_2 capture will have an incentive to operate at higher utilization because the cost to install the CCS system is largely fixed and the IRC section 45Q tax credit increases based on the amount of CO_2 captured and sequestered, any increase in utilization will be far outweighed by the substantial reductions in emission rate.

[453] DOE/NETL-2016/1796. "Eliminating the Derate of Carbon Capture Retrofits." May 31, 2016. Accessed at *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9*.
[454] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

v. Technology Advancement

The EPA considered the potential impact of designating CCS as the BSER for long-term coal-fired steam generating units on technology advancement, and the EPA is proposing that designating CCS as the BSER will provide for meaningful advancement of CCS technology, for many of the same reasons as noted in section VII.F.3.b.iii.(F) of this preamble.

b. Natural Gas Co-firing

The EPA also evaluated natural co-firing at 40 percent of the heat input as the potential BSER for long-term coal-fired steam generating units. Because the EPA is proposing natural gas co-firing as the BSER for medium-term units, details that are common to medium-term and long-term units are discussed in section X.D.2.b of the preamble. Based on the discussion therein, the EPA is proposing that natural gas co-firing is adequately demonstrated and that the non-air quality health and environmental effects and energy requirements are not unreasonable. The costs of natural gas co-firing for a long-term unit may also be reasonable. For example, for a representative unit with a 10-year amortization period, the cost of reductions is \$53/ton of CO_2. Finally, while the unit-level emission rate reductions of 16 percent achieved by 40 percent natural gas co-firing are reasonable, those reductions are less than CCS with 90 percent capture. Therefore, because CCS achieves more reductions at the unit level and is proposed as cost reasonable for long-term units, the EPA is not proposing natural gas co-firing as the BSER for long-term coal-fired steam generating units.

c. Conclusion

The EPA proposes that CCS at a capture rate of 90 percent is the BSER for long-term coal-fired steam generating units because CCS is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources, and there are vast sequestration opportunities across the continental U.S. Additionally, accounting for the tax credit under IRC section 45Q, the costs for CCS are reasonable. Moreover, any adverse non-air quality health and environmental impacts and energy requirements of CCS, including impacts on the power sector on a nationwide basis, are limited and are outweighed by the benefits of the significant emission reductions at reasonable cost. In contrast, co-firing 40 percent natural gas would achieve far fewer emission reductions without improving the cost effectiveness of the control strategy. These considerations provide the basis for proposing CCS as the best of the systems of emission reduction for long-term coal-fired power plants. In addition, determining CCS as the BSER promotes this useful control technology.

2. Medium-term Coal-fired Steam Generating Units

In this section of the preamble, the EPA evaluates CCS and natural gas co-firing as potential BSER for medium-term coal-fired steam generating units.

In section X.D.1.a of this preamble, the EPA evaluated CCS with 90 percent capture of CO_2 as the BSER for long-term coal-fired steam generating units. Much of this evaluation is relevant for medium-term units. However, because they have shorter operating horizons and, as a result, a shorter period for amortization and for collecting the IRC section 45Q tax credits, CCS would be less cost effective for those units. Therefore, the EPA is not proposing CCS as BSER for medium-term coal-fired steam generating units.

Instead, the EPA is proposing that 40 percent natural gas co-firing on a heat input basis is the BSER for medium-term coal-fired steam generating units. Co-firing 40 percent natural gas, on an annual average heat input basis, results in a 16 percent reduction in CO_2 emission rate. The technology has been adequately demonstrated, can be implemented at reasonable cost, does not have adverse non-air quality health and environmental impacts or energy requirements, and achieves meaningful reductions in CO_2 emissions. Co-firing also advances useful control technology and has acceptable national and long-term impacts on the energy sector, which provide additional, although not essential, support for treating it as the BSER.

a. CCS

In this section of the preamble, the EPA evaluates the use of CCS as the BSER for existing medium-term coal-fired steam generating units. This evaluation is much the same as the evaluation for long-term units, with the important difference of costs.

For long-term units, as discussed earlier in this preamble, the EPA's analysis used to evaluate the reasonableness of CCS costs employs a 12-year amortization period, which is consistent with the period of time during which the IRC section 45Q tax credit can be claimed. However, existing coal-fired steam generating units that choose to adopt federally enforceable commitments to permanently cease operations prior to 2040—ones in the medium-term subcategory, as well as in the near-term, and imminent-term subcategories—would have a shorter period to amortize capital costs and also would not be able to fully utilize the IRC section 45Q tax credit. As a result, for these sources, the cost effectiveness of CCS is less favorable. As noted in section X.D.1.a.ii.(C) of this preamble, for a 70 percent annual capacity factor and a 7-year amortization period, costs for the reference unit are $39/ton of CO_2 reduced and $34/MWh. This $/MWh generation cost is less favorable relative to the representative cost ($/MWh) for wet FGD, the costs for which are detailed in section VII.F.3.b.iii.(B)5. Due to the higher incremental cost of generation, the EPA is not proposing CCS as the BSER for medium-term coal-fired steam generating units.

While the EPA is not proposing CCS as BSER for the proposed subcategory of medium-term units, the EPA is taking comment on what dates most appropriately define the threshold between medium-term and long-term units and the EPA is also taking comment on the level of costs of CCS that should be considered reasonable.

b. Natural Gas Co-firing

In this section of the preamble, the EPA evaluates natural gas co-firing as potential BSER for medium-term coal-fired steam generating units. Considerations that are common to the proposed subcategories of existing coal-fired steam generating units are discussed in this section (X.D.1.a) of the preamble, in addition to considerations that are specific to medium-term units.

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal, so that the unit fires a combination of coal and natural gas, is known as "natural gas co-firing." The EPA is proposing natural gas co-firing at a level of 40 percent of annual heat input as BSER for medium-term coal-fired steam generating units.

i. Adequately Demonstrated

The EPA is proposing to find that natural gas co-firing at the level of 40 percent of annual heat input is adequately demonstrated for coal-fired steam generating units. Many existing coal-fired steam generating units already use some amount of natural gas, and several have co-fired at relatively high levels at or above 40 percent of heat input in recent years.

(A) Boiler Modifications

Most existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal, up to 100 percent natural gas. Generally, the modification of existing boilers to enable or increase natural gas firing typically involves the installation of new gas burners and related boiler modifications, including, for example, new fuel supply lines and modifications to existing air ducts. The introduction of natural gas as a fuel can reduce boiler efficiency slightly, due in large part to the relatively high hydrogen content of natural gas.

However, since the reduction in coal can result in reduced auxiliary power demand, the overall impact on net heat rate can range from a 2 percent increase to a 2 percent decrease.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source. Coal-fired steam generating units often use natural gas or oil as a startup fuel, to warm the units up before running them at full capacity with coal. While startup fuels are generally used at low levels (up to roughly 1 percent of capacity on an annual average basis), some coal-fired steam generating units have co-fired natural gas at considerably higher shares. Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[455] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.*, a year). Additionally, during that same 2015 through 2020 period, 29 coal-fired steam generating units co-fired natural gas at over 40 percent on an annual heat input basis. Because of the number of units that have demonstrated co-firing above 40 percent of heat input, the EPA is proposing that co-firing at 40 percent is adequately demonstrated. A more detailed discussion of the record of natural gas co-firing, including current trends, at coal-fired steam generating units is included in the *GHG Mitigation Measures – 111(d)* TSD.

[455] U.S. Environmental Protection Agency (EPA). "Power Sector Emissions Data." Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data web site: *https://campd.epa.gov*.

(B) Natural Gas Pipeline Development

In addition to any potential boiler modifications, the supply of natural gas is necessary to enable co-firing at existing coal-fired steam boilers. As discussed in the previous section, many plants already have at least some access to natural gas. In order to increase natural gas access beyond current levels, many will find it necessary to construct natural gas supply pipelines.

The U.S. natural gas pipeline network consists of approximately 3 million miles of pipelines that connect natural gas production with consumers of natural gas. To increase natural gas consumption at a coal-fired boiler without sufficient existing natural gas access, it is necessary to connect the facility to the natural gas pipeline transmission network via the construction of a lateral pipeline. The cost of doing so is a function of the total necessary pipeline capacity (which is characterized by the length, size, and number of laterals) and the location of the plant relative to the existing pipeline transmission network. The EPA estimated the costs associated with developing new lateral pipeline capacity sufficient to meet 60 percent of the net summer capacity at each coal-fired steam generating unit. As discussed in the *GHG Mitigation Measures – 111(d)* TSD, the EPA estimates that this lateral capacity would be sufficient to enable each unit to achieve 40 percent natural gas co-firing on an annual average basis.

The EPA considered the availability of the upstream natural gas pipeline capacity to satisfy the assumed co-firing demand implied by these new laterals. This analysis included pipeline development at all EGUs that could be included in this subcategory. The EPA's assessment reviewed the reasonableness of each assumed new lateral by determining whether the peak gas capacity of that lateral could be satisfied without modification of the transmission pipeline systems to which it is assumed to be connected. This analysis found that most, if not all, existing pipeline systems are currently able to meet the peak needs implied by these new laterals in aggregate, assuming that each existing coal-fired unit in the analysis co-fired with natural gas at a level implied by these new laterals, or 60 percent of net summer generating capacity. While this is a reasonable assumption for the analysis to support this mitigation measure in the BSER context, it is also a conservative assumption that overstates the amount of natural gas co-firing expected under the proposed rule.

The maximum amount of pipeline capacity, if all coal-fired steam capacity in the medium-term subcategory implemented the proposed BSER by co-firing 40 percent natural gas, would be a fraction of the pipeline capacity constructed recently. The EPA estimates that this maximum total capacity would be about 17.3 billion cubic feet per day, which would require almost 4,000 miles of pipeline costing roughly $13.3 billion. Over 5 years, this maximum total incremental pipeline capacity would amount to 800 miles per year and approximately $2.7 billion per year in capital expenditures, on average. By comparison, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year, with a total capacity of 10 to 25 billion cubic feet per day. This represents an estimated annual investment of up to nearly $15 billion. These historical annual values are much higher than the maximum annual values that could be expected under this proposed BSER measure—which, as noted above, represent a conservative estimate that overstates the amount of co-firing that the EPA projects would occur under this proposed rule.

These conservatively high estimates of pipeline requirements also compare favorably to industry projections of future pipeline capacity additions. Based on a review of a 2018 industry report, titled “North America Midstream Infrastructure through 2035: Significant Development Continues,” investment in midstream infrastructure development is expected to average about

$37 billion per year through 2035, which is lower than historical levels. Approximately $10 to $20 billion annually is expected to be invested in natural gas pipelines through 2035. This report also projects that an average of over 1,400 miles of new natural gas pipeline will be built through 2035, which is similar to the approximately 1,670 miles that were built on average from 2013 to 2017. These values are considerably greater than the average annual expenditure of $2.7 billion on 800 miles per year of new pipeline construction that would be necessary for the entire operational fleet of coal-fired steam generating units to co-fire with natural gas. The actual pipeline investment for this subcategory would be substantially lower.

ii. Costs

The capital costs associated with the addition of new gas burners and other necessary boiler modifications depend on the extent to which the current boiler is already able to co-fire with some natural gas and on the amount of gas co-firing desired. The EPA estimates that, on average, the total capital cost associated with modifying existing boilers to operate at up to 100 percent of heat input using natural gas is approximately $52/kW. These costs could be higher or lower, depending on the equipment that is already installed and the expected impact on heat rate or steam temperature.

While fixed O&M (FOM) costs can potentially decrease as a result of decreasing the amount of coal consumed, it is common for plants to maintain operation of one coal pulverizer at all times, which is necessary for maintaining several coal burners in continuous service. In this case, coal handling equipment would be required to operate continuously and therefore natural gas co-firing would have limited effect on reducing the coal-related FOM costs. Although, as noted, coal-related FOM costs have the potential to decrease, the EPA does not anticipate a significant increase in impact on FOM costs related to co-firing with natural gas.

In addition to capital and FOM cost impacts, any additional natural gas co-firing would result in incremental costs related to the differential in fuel cost, taking into consideration the difference in delivered coal and gas prices, as well as any potential impact on the overall net heat rate. The EPA's post-IRA 2022 reference case projects that in 2030, the average delivered price of coal will be $1.47/MMBtu and the average delivered price of natural gas will be $2.53/MMBtu. Thus, assuming the same level of generation and no impact on heat rate, the additional fuel cost would be above $1/MMBtu on average in 2030. The total additional fuel cost could increase or decrease depending on the potential impact on net heat rate. An increase in net heat rate, for example, would result in more fuel required to produce a given amount of generation and thus additional cost. In the *GHG Mitigation Measures – 111(d)* TSD, the EPA's cost estimates assume a 1 percent increase in net heat rate.

Finally, for plants without sufficient access to natural gas, it is also necessary to construct new natural gas pipelines ("laterals"). Pipeline costs are typically expressed in terms of dollars per inch of pipeline diameter per mile of pipeline distance (*i.e.*, dollars per inch-mile), reflecting the fact that costs increase with larger diameters and longer pipelines. On average, the cost for lateral development within the contiguous U.S. is approximately $280,000 per inch-mile (2019$), which can vary based on site-specific factors. The total pipeline cost for each coal-fired steam generating unit is a function of this cost, as well as a function of the necessary pipeline capacity and the location of the plant relative to the existing pipeline transmission network. The pipeline capacity required depends on the amount of co-firing desired as well as on the desired level of generation—a higher degree of co-firing while operating at full load would require more pipeline capacity than a lower degree of co-firing while operating at partial load. It is reasonable to assume that most plant owners would develop sufficient pipeline capacity to deliver the maximum amount of desired gas use in any moment, enabling higher levels of co-firing during periods of lower fuel price differentials. Once the necessary pipeline capacity is determined, the total lateral cost can be estimated by considering the location of each plant relative to the existing natural gas transmission pipelines as well as the available excess capacity of each of those existing pipelines. For purposes of the cost reasonableness estimates as follows, the EPA assumes pipeline costs of $92/kW, which is the median value of all unit-level pipeline cost estimates, as explained in the *GHG Mitigation Measures – 111(d)* TSD. The range in costs reflects a range in the amortization period of the capital costs over 6 to 10 years, which is consistent with the amount of time over which the units in the medium-term subcategory could be operational.

The EPA sums the natural gas co-firing costs as follows: For a typical base load coal-fired steam generating unit in 2030, the EPA estimates that the cost of co-firing with 40 percent natural gas on an annual average basis is approximately $53 to $66/ton CO_2 reduced, or $9 to $12/MWh, respective to amortization periods of 10 to 6 years. This estimate is based on the characteristics of a typical coal-fired unit in 2021 (400 MW capacity and an average heat rate of 10,500 Btu/kWh) operating at a typical capacity factor of about 50 percent, and it assumes a pipeline cost of $92/kW, as discussed earlier in this preamble.

Based on the coal-fired steam generating units that existed in 2021 and that do not have known plans to cease operations or convert to gas by 2030, and assuming that each of those units continues to operate at the same level in 2030 as it operated in 2017-2021, on average, the EPA estimates that the weighted average cost of co-firing with 40 percent natural gas on an annual average basis is approximately $64 to $78/ton CO_2 reduced, or $11 to $14/MWh. The $/ton cost estimate is lower than average for approximately 82 GW, and the $/MWh cost estimate is lower than average for 86 GW (about 69 percent and 72 percent, respectively, of the relevant coal fleet). These estimates and all underlying assumptions are explained in detail in the *GHG Mitigation Measures – 111(d)* TSD.

As was described in section X.D.1 of this preamble, the EPA has compared the estimated costs discussed in section X.D.2 of this preamble to costs that coal-fired steam generating units have incurred to install controls that reduce other air pollutants, such as SO_2. Representative wet FGD SO_2 emission control costs are \$15.00 to \$18.50/MWh, as detailed in section VII.F.3.b.iii.(B)5 of this preamble. The estimated range of annualized costs of natural gas co-firing (approximately \$9–\$14/MWh) is lower than or comparable to the representative annualized costs of installing and operating wet FGD, which are detailed in section VII.F.3.b.iii.(B)5 of this preamble. The range of cost effectiveness estimates presented in this section is lower than previously estimated by the EPA in the proposed CPP, for several reasons. Since then, the expected difference between coal and gas prices has decreased significantly, from over \$3/MMBtu to about \$1/MMBtu in this proposal. Additionally, a recent analysis performed by Sargent and Lundy for the EPA supports a considerably lower capital cost for modifying existing boilers to co-fire with natural gas. The EPA also recently conducted a highly detailed facility-level analysis of natural gas pipeline costs, the median value of which is slightly lower than the value used by the EPA previously to approximate the cost of co-firing at a representative unit.

Based on the range of costs presented in this section, the EPA is proposing that the costs of natural gas co-firing are reasonable for the medium-term coal-fired steam generating unit subcategory.

iii. Non-air Quality Health and Environmental Impact and Energy Requirements

Natural gas co-firing for steam generating units is not expected to have any significant adverse consequences related to non-air quality health and environmental impacts or energy requirements.

(A) Non-GHG Emissions

Non-GHG emissions are reduced when steam generating units co-fire with natural gas because less coal is combusted. SO_2, $PM_{2.5}$, acid gas, mercury and other hazardous air pollutant emissions that result from coal combustion are reduced proportionally to the amount of natural gas consumed, *i.e.*, under this proposal, by 40 percent. Natural gas combustion does produce NO_X emissions, but in lesser amounts than from coal-firing. However, the magnitude of this reduction is dependent on the combustion system modifications that are implemented to facilitate natural gas co-firing.

Additionally, sufficient regulations exist related to natural gas pipelines and transport that assure natural gas can be safely transported with minimal risk of environmental release. PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.6 million mile pipeline transportation system. Recently, PHMSA finalized a rule that will improve the safety and strengthen the environmental protection of more than 300,000 miles of onshore gas transmission pipelines.[456] PHMSA also recently promulgated a rule covering natural gas transmission,[457] as well as a rule that significantly expanded the scope of

[456] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (87 FR 52224; August 24, 2022).
[457] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180; October 1, 2019).

safety and reporting requirements for more than 400,000 miles of previously unregulated gas gathering lines.[458] Additionally, FERC oversees the development of new natural gas pipelines.

(B) Energy Requirements

The introduction of natural gas co-firing will cause steam boilers to be slightly less efficient due to the high hydrogen content of natural gas. Co-firing at levels between 20 percent and 100 percent can be expected to decrease boiler efficiency between 1 percent and 5 percent. However, despite the decrease in boiler efficiency, the overall net output efficiency of a steam generating unit that switches from coal- to natural gas-firing may change only slightly, in either a positive or negative direction. Since co-firing reduces coal consumption, the auxiliary power demand related to coal handling and emissions controls typically decreases as well. While a site-specific analysis would be required to determine the overall net impact of these countervailing factors, generally the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent.

The EPA previously determined in the ACE Rule (84 FR 32520 at 32545; July 8, 2019) that "co-firing natural gas in coal-fired utility boilers is not the best or most efficient use of natural gas and […] can lead to less efficient operation of utility boilers." That determination was informed by the more limited supply of natural gas, and the larger amount of coal-fired EGU capacity and generation, in 2019. Since that determination, the expected supply of natural gas has expanded considerably, and the capacity and generation of the existing coal-fired fleet has decreased, reducing the total mass of natural gas that might be required for sources to implement this measure. Additionally, the natural gas co-firing measure is now being proposed for a

[458] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments (86 FR 63266; November 15, 2021).

medium-term coal-fired steam generating unit subcategory, a group of units that will operate at most for 10 years following the compliance date, which would further reduce the total amount of required natural gas.

Furthermore, regarding the efficient operation of boilers, the ACE determination was based on the observation that "co-firing can negatively impact a unit's heat rate (efficiency) due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product." That finding does not consider the fact that the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent, and therefore the net impact on overall utility boiler efficiency for each steam generating unit is uncertain.

For all of these reasons, the EPA is proposing that natural gas co-firing at medium-term coal-fired steam generating units does not result in any significant adverse consequences related to energy requirements.

Additionally, the EPA considered longer term impacts on the energy sector, and the EPA is proposing these impacts are reasonable. Designating natural gas co-firing as the BSER for medium-term coal-fired steam generating units would not have significant adverse impacts on the structure of the energy sector. Steam generating units that currently are coal-fired would be able to remain primarily coal-fired. The replacement of some coal with natural gas as fuel in these sources would not have significant adverse effects on the price of natural gas or the price of electricity.

iv. Extent of Reductions in CO_2 Emissions

One of the primary benefits of natural gas co-firing is emission reduction. CO_2 emissions are reduced by approximately 4 percent for every additional 10 percent of co-firing. When shifting from 100 percent coal to 60 percent coal and 40 percent natural gas, CO_2 stack emissions are reduced by approximately 16 percent. Non-CO_2 emissions are reduced as well, as noted earlier in this preamble.

v. Technology Advancement

Natural gas co-firing is already well-established and widely used by coal-fired steam boiler generating units. As a result, this proposed rule is not likely to lead to technological advances or cost reductions in the components of natural gas co-firing, including modifications to boilers and pipeline construction. However, greater use of natural gas co-firing may lead to improvements in the efficiency of conducting natural gas co-firing and operating the associated equipment.

c. Conclusion

The EPA proposes that natural gas co-firing at 40 percent of heat input is the BSER for medium-term coal-fired steam generating units because natural gas co-firing is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources. Additionally, the costs for natural gas co-firing are reasonable. Moreover, any adverse non-air quality health and environmental impacts and energy requirements of natural gas co-firing are limited and are outweighed by the benefits of the emission reductions at reasonable cost. In contrast, CCS, although achieving greater emission reductions, would be less cost-effective, in general, for the proposed subcategory of medium-term units.

While the EPA is not proposing CCS as BSER for the proposed subcategory definition of medium-term units, the EPA is taking comment on the dates that define the threshold between medium-term and long-term units and on what amount of costs should be considered reasonable.

3. Imminent-term and Near-term Coal-fired Steam Generating Units

In this section of the preamble, the EPA evaluates CCS, natural gas co-firing, and routine methods of operation and maintenance as the BSER for imminent-term and near-term coal-fired steam generating units. Primarily because of the effect of a short operating horizon on the cost of controls for these units, the EPA proposes routine methods of operation and maintenance as the BSER.

a. CCS

As noted in section X.D.2.a of this preamble, the EPA is not proposing CCS for medium-term units due to $/MWh costs being less favorable based on the appropriate cost metrics. Because of the shorter operating horizons for imminent-term and near-term coal-fired steam generating units, CCS is less cost favorable for them than for medium-term units. Therefore, the EPA is not proposing CCS as BSER for imminent-term or near-term coal-fired steam generating units. Additional details of cost values for amortization periods representative of imminent-term and near-term units are available in the *GHG Mitigation Measures – 111(d)* TSD.

b. Natural Gas Co-firing

Much of the discussion of natural gas co-firing in section X.D.2.b of this preamble for medium-term units is relevant for imminent-term and near-term units, except that natural gas co-firing is less cost effective for the latter units because of their short operating horizons. For a 2-year amortization period, annualized costs for the representative unit are $130/ton of CO_2 reduced and $23/MWh of generation. Therefore, the EPA is not proposing natural gas co-firing as BSER for imminent-term or near-term units. Additional details of cost are available in the *GHG Mitigation Measures – 111(d)* TSD.

c. Routine Methods of Operation and Maintenance

For the imminent-term and near-term coal-fired steam generating units, the EPA is proposing that the BSER is routine methods of operation and maintenance already occurring at the unit, so as to maintain the current unit-specific CO_2 emission rates (expressed as lb CO_2/MWh). Furthermore, requiring additional investment in those units could have the counterproductive effects of leading them to increase operations and thereby increase CO_2 emissions.

Routine methods of operation and maintenance are adequately demonstrated because units already operate by those methods. They will not result in additional costs from any controls, and will not create adverse non-air quality health and environmental impacts or energy requirements. They will not achieve CO_2 emission reductions at the unit level relative to current performance, but they can prevent worsening of emission rates over time. Although they do not advance useful control technology, they do not have adverse impacts on the energy sector from a nationwide or long-term perspective.

4. Degree of Emission Limitation

Under CAA section 111(d), once the EPA determines the BSER, it must determine the "degree of emission limitation" achievable by the application of the BSER. States then determine standards of performance and include them in the state plans, based on the specified degree of emission limitation. Proposed presumptive standards of performance are detailed in section XI.D of this preamble. There is substantial variation in emission rates among coal-fired steam generating units—the range is, approximately, from 1,700 lb CO_2/MWh-gross to 2,500 lb CO_2/MWh-gross—which makes it challenging to determine a single, uniform emission limit. Accordingly, for each of the four subcategories of coal-fired steam generating units, the EPA is proposing to determine the degree of emission limitation by a percentage change in emission rate, as follows:

a. Long-term Coal-fired Steam Generating Units

As discussed earlier in this preamble, the EPA is proposing the BSER for long-term coal-fired steam generating units as "full-capture" CCS, defined as 90 percent capture of the CO_2 in the flue gas. The degree of emission limitation achievable by applying this BSER can be determined on a rate basis. A capture rate of 90 percent results in reductions in the emission rate of 88.4 percent on a lb CO_2/MWh-gross basis, and this reduction in emission rate can be observed over an extended period (*e.g.*, an annual calendar-year basis). Therefore, the EPA is proposing that the degree of emission limitation for long-term units is an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.*, an annual calendar-year basis).

As noted in section X.D.1.a of this preamble, new CO_2 capture retrofits on existing coal-fired steam generating units may achieve capture rates greater than 90 percent, and the EPA is taking comment on a range of capture rates that may be achievable. As also discussed in section X.D.1.a, the operating availability (*i.e.*, the amount of time a process operates relative to the amount of time it planned to operate) of industrial processes is usually less than 100 percent. Assuming that CO_2 capture achieves 90 percent capture when available to operate, that CCS is available to operate 90 percent of the time the coal-fired steam generating unit is operating, and that the steam generating unit operates the same whether or not CCS is available to operate, total emission reductions would be 81 percent. Higher levels of emission reduction could occur for higher capture rates coupled with higher levels of operating availability relative to operation of the steam generating unit. If the steam generating unit were not permitted to operate when CCS was unavailable, there may be local reliability consequences, and the EPA is soliciting comment on how to balance these issues. Additionally, the EPA is soliciting comment on a range of the degree of emission limitation achievable, in the form of a reduction in emission rate of 80 to 90 percent when determined over an extended period (*e.g.*, an annual calendar-year basis).

b. Medium-term Coal-fired Steam Generating Units

As discussed earlier in this preamble, the BSER for medium-term coal-fired steam generating units is 40 percent natural gas co-firing. The application of 40 percent natural gas co-firing results in reductions in the emission rate of 16 percent. Therefore, the degree of emission limitation for these units is a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.*, an annual calendar-year basis).

c. Imminent-term and Near-term Coal-fired Steam Generating Units

As discussed above, the BSER for imminent-term and near-term coal-fired steam generating units is routine methods of operation and maintenance. Application of this BSER results in no increase in emission rate. Thus, the degree of emission limitation corresponding to the application of the BSER is no increase in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.*, an annual calendar-year basis).

5. Other Emission Reduction Measures

a. Heat Rate Improvements

Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy input, measured in Btu, required to generate one kWh of electricity. The lower an EGU's heat rate, the more efficiently it operates. As a result, an EGU with a lower heat rate will consume less fuel and emit lower amounts of CO_2 and other air pollutants per kWh generated as compared to a less efficient unit. HRI measures include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. The EPA considered HRI to be part of the BSER in the CPP and to be the BSER in the ACE Rule. However, the reductions that may be achieved by HRI are small relative to the reductions from natural gas co-firing and CCS. Also, some facilities that apply HRI would, as a result of their increased efficiency, increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants), a phenomenon that the EPA has termed the “rebound effect.” Therefore, the EPA is not proposing HRI as a part of BSER.

i. CO_2 Reductions from HRI in Prior Rulemakings

In the CPP, the EPA quantified emission reductions achievable through heat rate improvements on a regional basis by an analysis of historical emission rate data, taking into consideration operating load and ambient temperature. The Agency concluded that EGUs can achieve on average a 4.3 percent improvement in the Eastern Interconnection, a 2.1 percent improvement in the Western Interconnection, and a 2.3 percent improvement in the Texas Interconnection. See 80 FR 64789 (October 23, 2015). The Agency then applied all three of the building blocks to 2012 baseline data and quantified, in the form of CO_2 emission rates, the reductions achievable in each interconnection in 2030, and then selected the least stringent as a national performance rate. Id. At 64811–19. The EPA noted that building block 1 measures could not by themselves constitute the BSER because the quantity of emission reductions achieved would be too small and because of the potential for an increase in emissions due to increased utilization (*i.e.*, the “rebound effect”).

A description of the ACE Rule is detailed in section IX of this preamble.

ii. Updated CO_2 Reductions from HRI

The HRI measures include improvements to the boiler island (*e.g.*, neural network system, intelligent sootblower system), improvements to the steam turbine (*e.g.*, turbine overhaul and upgrade), other equipment upgrades (*e.g.*, variable frequency drives), and improvements in operation and maintenance practices. Specific details of the HRI measures are described in the *GHG Mitigation Measures – 111(d)* TSD and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Mem*o), available in docket. Most HRI measures achieve reductions in heat rate of less than 2 percent. Steam path overhaul and upgrade may achieve reductions up to 5.15 percent, with the average being around 1.5 percent. Different combinations of HRI measures do not necessarily result in cumulative reductions in emission rate (*e.g.*, intelligent sootblowing systems combined with neural network systems). Some of the HRI measures (*e.g.*, variable frequency drives) only impact heat rate on a net generation basis by reducing the parasitic load on the unit. Assuming many of the HRI measures could be applied to a unit, it is possible that some units could achieve a maximum emission rate reduction of up to 5 percent. However, the reductions that the fleet could achieve on average are likely much smaller. The unit level reductions in emission rate from HRI are small relative to CCS or natural gas co-firing. In the CPP and ACE Rule, the EPA viewed the CCS and natural gas co-firing as too costly to qualify as the BSER; those costs have fallen since those rules and, as a result, CCS and natural gas co-firing do qualify as the BSER for the long-term and medium-term subcategories, respectively.

iii. Potential for Rebound in CO_2 Emissions

Reductions achieved on a rate basis from HRI may not result in overall emission reductions and could instead cause a “rebound effect” from increased utilization. A rebound effect would occur where, because of an improvement in its heat rate, a steam generating unit experiences a reduction in variable operating costs that makes the unit more competitive relative to other EGUs and consequently raises the unit's output. The increase in the unit's CO_2 emissions associated with the increase in output would offset the reduction in the unit's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of output. The extent of the offset would depend on the extent to which the unit's generation increased. The CPP did not consider HRI to be BSER on its own, in part because of the potential for a rebound effect. Analysis for the ACE Rule, where HRI was the entire BSER, observed a rebound effect for certain sources in some cases. In this action, where different subcategories of units are proposed to be subject to different BSER measures, steam generating units in a hypothetical subcategory with HRI as BSER could experience a rebound effect. Because of this potential for perverse GHG emission outcomes resulting from deployment of HRI at certain steam generating units, coupled with the relatively minor overall GHG emission reductions that would be expected from this measure, the EPA is not proposing HRI as the BSER for any subcategory of existing coal-fired steam generating units.

E. Natural Gas-fired and Oil-fired Steam Generating Units

In this section of the preamble, the EPA is addressing natural gas- and oil-fired steam generating units. The EPA is proposing the BSER and degree of emission limitation achievable by application of the BSER for those units and identifying the associated emission rates that states may apply to these units. For the reasons described here, the EPA is proposing subcategories based on load level (*i.e.*, annual capacity factor), specifically, units that are base load, intermediate load, and low load. At this time, the EPA is not proposing requirements for low load units but is taking comment on a BSER of "clean fuels" for those units. The EPA is proposing routine methods of operation and maintenance as BSER for intermediate and base load units. Applying that BSER would not achieve emission reductions but would prevent increases in emission rates. The EPA is proposing presumptive standards of performance that differ between intermediate and base load units due to their differences in operation, as detailed in section XI.D.1.f of this preamble. The EPA is also proposing a separate subcategory for non-continental oil-fired steam generating units, which operate differently from continental units, with presumptive standards of performance detailed in section XI.D.1.g of this preamble.

Natural gas- and oil-fired steam generating units combust natural gas or distillate fuel oil or residual fuel oil in a boiler to produce steam for a turbine that drives a generator to create electricity. In non-continental areas, existing natural gas- and oil-fired steam generating units may provide base load power, but in the continental U.S., most existing units operate in a load-following manner. There are approximately 200 natural gas-fired steam generating units and fewer than 30 oil-fired steam generating units in operation in the continental U.S. Fuel costs and inefficiency relative to other technologies (*e.g.*, combustion turbines) result in operation at lower annual capacity factors for most units. Based on data reported to EIA and CAMD for the contiguous U.S., for natural gas-fired steam generating units in 2019, the average annual capacity factor was less than 15 percent and 90 percent of units had annual capacity factors less than 35 percent. For oil-fired steam generating units in 2019, no units had annual capacity factors above 8 percent. Additionally, their load-following method of operation results in frequent cycling and a greater proportion of time spent at low hourly capacities, when generation is less efficient. Furthermore, because startup times for most boilers are usually long, natural gas steam generating units may operate in standby mode between periods of peak demand. Operating in standby mode requires combusting fuel to keep the boiler warm, and this further reduces the efficiency of natural gas combustion.

Unlike coal-fired steam generating units, the CO_2 emission rates of oil- and natural gas-fired steam generating units that have similar annual capacity factors do not vary considerably between units. This is partly due to the more uniform qualities (*e.g.*, carbon content) of the fuel used. However, the emission rates for units that have different annual capacity factors do vary considerably, as detailed in the *Natural Gas- and Oil-fired Steam Generating Unit* TSD. Low annual capacity factor units cycle frequently, have a greater proportion of CO_2 emissions that may be attributed to startup, and have a greater proportion of generation at inefficient hourly capacities. Intermediate annual capacity factor units operate more often at higher hourly capacities, where CO_2 emission rates are lower. High annual capacity factor units operate still more at base load conditions, where units are more efficient and CO_2 emission rates are lower. Based on these performance differences between these load levels, the EPA is, in general, proposing to divide natural gas- and oil-fired steam generating units into three subcategories each—low load, intermediate load, and base load—as specified in section X.C.2 of this preamble: “low” load is defined by annual capacity factors less than 8 percent, “intermediate” load is defined by annual capacity factors greater than or equal to 8 percent and less than 45 percent, and “base” load is defined by annual capacity factors greater than 45 percent.

1. Options Considered for BSER

The EPA has considered various methods for controlling CO_2 emissions from natural gas- and oil-fired steam generating units to determine whether they meet the criteria for BSER. Co-firing natural gas cannot be the BSER for these units because natural gas- and oil-fired steam generating units already fire large proportions of natural gas. Most natural gas-fired steam generating units fire more than 90 percent natural gas on a heat input basis, and any oil-fired steam generating units that would potentially operate above an annual capacity factor of around 15 percent would combust natural gas as a large proportion of their fuel as well. Nor is CCS a candidate for BSER. The utilization of most gas-fired units, and likely all oil-fired units, is relatively low, and as a result, the amount of CO_2 available to be captured is low. However, the capture equipment would still need to be sized for the nameplate capacity of the unit. Therefore, the capital and operating costs of CCS would be high relative to the amount of CO_2 available to be captured. Additionally, again due to lower utilization, the amount of IRC section 45Q tax credits that owner/operators could claim would be low. Because of the relatively high costs and the relatively low cumulative emission reduction potential for these natural gas- and oil-fired steam generating units, the EPA is not proposing CCS as the BSER for them.

The EPA has reviewed other possible controls but is not proposing any of them as the BSER for natural gas- and oil-fired units either. Co-firing hydrogen in a boiler is technically possible, but, for the same reasons discussed in section VII of this preamble, the only hydrogen that could be considered for the BSER would be low-GHG hydrogen, and there is limited availability of that hydrogen now and in the near future. Additionally, for natural gas-fired steam generating units, setting a future standard based on hydrogen would have limited GHG reduction benefits given the low utilization of natural gas- and oil-fired steam generating units. Lastly, HRI for these types of units would face many of the same issues as for coal-fired steam generating units; in particular, HRI could result in a rebound effect that would increase emissions.

However, the EPA recognizes that natural gas- and oil-fired steam generating units could possibly, over time, operate more, in response to other changes in the power sector. Additionally, some coal-fired steam generating units have converted to 100 percent natural gas-fired, and it is possible that more may do so in the future. Moreover, in part because the fleet continues to age, the plants may operate with degrading emission rates. In light of these possibilities, identifying the BSER and degrees of emission limitation for these sources would be useful to provide clarity and prevent backsliding in GHG performance. Therefore, the EPA is proposing BSER for intermediate and base load natural gas- and oil-fired steam generating units to be routine methods of operation and maintenance, such that the sources could maintain the emission rates (on a lb/MWh-gross basis) currently maintained by the majority of the fleet across discrete ranges of annual capacity factor. The EPA is proposing this BSER for intermediate load and base load natural gas- and oil-fired steam generating units, regardless of the operating horizon of the unit.

A BSER based on routine methods of operation and maintenance is adequately demonstrated because units already operate with those practices. There are no or negligible additional costs because there is no additional technology that units are required to apply and there is no change in operation or maintenance that units must perform. Similarly, there are no adverse non-air quality health and environmental impacts or adverse impacts on energy requirements. Nor do they have adverse impacts on the energy sector from a nationwide or long-term perspective. The EPA's initial modeling, which supports this proposed rule, indicates that by 2040, a number of natural gas-fired steam generating units have remained in operation since 2030, although at reduced annual capacity factors. There are no CO_2 reductions that may be achieved at the unit level, but applying the BSER should preclude increases in emission rates. Routine methods of operation and maintenance do not advance useful control technology, but this point is not significant enough to offset their benefits.

The EPA is also taking comment on, but not proposing, a BSER of "clean fuels" for low load natural gas- and oil-fired steam generating units. As noted earlier in this preamble, non-coal fossil fuels combusted in utility boilers typically include natural gas, distillate fuel oil (*i.e.*, fuel oil No. 1 and No. 2), and residual fuel oil (*i.e.*, fuel oil No. 5 and No. 6). The EPA previously established "clean fuels" as BSER in the 2015 NSPS for new non-base load natural gas- and multi-fuel-fired stationary combustion turbines (80 FR 64615–17; October 23, 2015), and the EPA is similarly proposing "clean fuels" as BSER for new low load combustion turbines as described in section VII of this preamble. For low load natural gas- and oil-fired steam generating units, the high variability in emission rates associated with the variability of load at the lower-load levels limits the benefits of a BSER based on routine maintenance and operation. That is because the high variability in emission rates would make it challenging to determine an emission rate (*i.e.*, on a lb CO_2/MWh-gross basis) that could serve as the presumptive standard of performance that would reflect application of a BSER of routine operation and maintenance. On the other hand, for those units, a BSER of "clean fuels" and an associated presumptive standard of performance based on a heat input basis, as described in section XI.D of this preamble, may be reasonable. The EPA is soliciting comment on the fuel types that would constitute "clean fuels" specific to low load natural gas- and oil-fired steam generating units.

2. Degree of Emission Limitation

As discussed above, because the proposed BSER for base load and intermediate load natural gas- and oil-fired steam generating plants is routine operation and maintenance, which the units are, by definition, already employing, the degree of emission limitation by application of this BSER is no increase in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*e.g.*, an annual calendar year).

XI. State Plans for Proposed Emission Guidelines for Existing Fossil Fuel-fired EGUs

A. Overview

State plan submissions under these emission guidelines are governed by the requirements of 40 CFR part 60, subpart Ba (subpart Ba).[459] The EPA proposed to revise certain aspects of 40 CFR part 60, subpart Ba, in its December 2022 proposal, "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)" (proposed subpart Ba).[460] The Agency intends to finalize revisions to 40 CFR part 60, subpart Ba, before promulgating these emission guidelines. Therefore, state plans and state plan submissions under these proposed emission guidelines would be subject to the requirements of subpart Ba as revised in that future final action, including any changes the EPA makes to the proposal in response to public comments. To the extent the EPA is proposing to add to, supersede, or otherwise vary the requirements of subpart Ba for the purposes of these particular emission guidelines, those proposals are explicitly addressed in this section. Unless expressly amended or superseded in these proposed emission guidelines, the provisions of subpart Ba, as revised by the EPA's forthcoming final rule, would apply.

This section provides information on several aspects of state plan development, including compliance deadlines, a presumptive methodology for establishing standards of performance for affected EGUs, compliance flexibilities, and state plan components and submission. The EPA notes that, in section X of this preamble, comment is solicited on ranges for dates and values for defining subcategories, BSER, and degrees of emission limitation, and that those solicitations for

[459] 40 CFR 60.20a–60.29a.
[460] See 87 FR 79176 (December 23, 2022); see also id., Docket ID No. EPA-HQ-OAR-2021-0527-0002 (memorandum to docket containing proposed revisions to 40 CFR part 60, subpart Ba).

comment extend to the proposed values and dates discussed in this section of the preamble. In Section XI.B, the EPA proposes and explains its reasoning for a compliance deadline of January 1, 2030. In Section XI.C, the EPA describes its requirement that state plans achieve equivalent stringency to the EPA's BSER. Section XI.D proposes a presumptive methodology for calculating the standards of performance for affected EGUs based on subcategory as well as requirements related to invoking RULOF to apply a less stringent standard of performance than results from the EPA's presumptive methodology. Section XI.D also describes requirements for increments of progress and milestones for federally enforceable commitments to cease operations. Because many of the subcategories take into account operating horizon, the EPA is proposing milestones to provide the public with assurance that steps towards permanently ceasing operations will be concluded in a timely manner. In Section XI.E, the EPA requests comment on whether emission trading and averaging are appropriate in the context of these emission guidelines. Finally, Section XI.F describes what must be included in state plans, including plan components specific to these emission guidelines and requirements for conducting meaningful engagement.

B. Compliance Deadlines

The EPA is proposing a compliance date of January 1, 2030. This means that starting on January 1, 2030, designated EGUs would be required to demonstrate compliance with the standards of performance and associated requirements in their applicable state plans under these emission guidelines. The EPA is proposing that this is the soonest compliance with standards of performance could reasonably commence based on the proposed state plan submission timeline (24 months; see section XI.F.2 of this preamble) and the amount of time affected EGUs will need to install CCS or natural gas co-firing. However, the BSER for other subcategories are routine methods of operation and maintenance, which can be applied earlier. Therefore, the EPA is soliciting comment on compliance dates defined by the date of approval of the state plan or January 1, 2030, whichever is earlier, for imminent-term coal-fired steam generating units, near-term coal-fired steam generating units, and the different subcategories of natural gas- and oil-fired steam generating units.

The proposed compliance timeframe in these proposed emission guidelines is based on the amount of time the EPA believes is needed to comply with standards of performance based on implementation of natural gas co-firing or CCS. Each of these systems would require several years to plan, permit, and construct. However, as explained further in section XI.F.2 of this preamble, the EPA is proposing to adjust the state plan submission deadline so that certain necessary planning and design steps for natural gas co-firing or CCS implementation can take place as part of the state plan development process. That is, we expect that some of the planning and design steps described below would take place prior to state plan submission. The EPA believes that coordinating state plan development and implementation in this manner reflects how the owners/operators of affected EGUs and states would actually undertake the steps leading to ultimate deployment of a control technology and compliance with a standard of performance.

The *GHG Mitigation Measures – 111(d)* TSD discusses the timeframes for implementation of natural gas co-firing and CCS at existing coal-fired EGUs. Based on this analysis, the time needed to design and implement CCS is an important aspect for setting a compliance date under these emission guidelines. CCS projects will include planning, design, and construction of both carbon capture and transport and storage systems; the EPA believes that all of these steps can be completed within roughly 5 years.[461] Deployment of carbon capture systems starts with a technical and economic feasibility evaluation, including a (Front End Engineering Design (FEED) study. The owner/operator of an affected EGU would then proceed to making technical and commercial arrangements, including arranging project financing and permitting. These initial steps do not need to be undertaken sequentially and may be complete in 3 years or less. As noted above, the EPA also believes that at least some of these project design and development steps, including feasibility evaluations and FEED studies, can and will be completed prior to state plan submission deadline. The EPA believes that the commencement of CCS project implementation activities, including more detailed engineering work and procurement, construction of the carbon capture system, and startup and testing, will overlap with the final steps of the initial project design and development phase. Project implementation takes approximately 3 years to complete.

In addition to planning and implementing a carbon capture system, the owners/operators of affected EGUs will also have to design and construct a system for transporting and storing captured CO_2. The necessary steps for implementing transport and storage can be undertaken simultaneously with development of the capture system, and the EPA believes they can also be completed within roughly 5 years. As with the planning and design phases associated with a carbon capture system, the EPA believes that the initial phases of planning and design for CO_2 transport and storage, including site characterization and pipeline feasibility and design activities, can and will occur prior to state plan submission deadline. First, the owner/operator of an affected EGU would undertake a feasibility analysis associated with CO_2 transport and storage, as well as site characterization and permitting of potential storage areas. These three

[461] *GHG Mitigation Measures- 111(d)* TSD, chapter 4.7.1.

steps can overlap with each other and the EPA anticipates they will take 2–3 years to complete. Similar to the design and implementation of the carbon capture system, the EPA believes there is significant opportunity to overlap the design and planning phase for CO_2 transport and storage with the engineering and construction phase, which is anticipated to take 2–3 years.

The EPA expects that implementation of natural gas co-firing projects, including any necessary construction of natural gas pipelines, can be completed in approximately 3.5 years. As discussed in the *GHG Mitigation Measures – 111(d)* TSD,[462] any necessary boiler modifications to accommodate natural gas co-firing can be completed within 3 years. The process of planning, permitting, and construction for boiler modifications can occur simultaneously with the steps that owners/operators of affected EGUs would need to undertake if construction of a new natural gas pipeline is needed. The time required to develop and construct natural gas laterals can be broken into three phases: planning and design; permitting and approval; and construction. It is reasonable to assume that the planning and design phase can typically be completed in a matter of months and will often be finalized in less than a year. The time required to complete the permitting and approval phase can vary. Based on a review of recent FERC data, the average time for pipeline projects similar in scope to the projects considered in this TSD is about 1.5 years and would likely not exceed 4 years. Finally, the actual construction could likely be completed in less than 1 year. Based on a sum of these estimates, the EPA believes that 3.5 years is a reasonable timeframe for pipeline projects.

The EPA expects that final emission guidelines will be published in June 2024 and is proposing a state plan submission deadline that is 24 months from publication, meaning June 2026. The proposed compliance date is January 1, 2030. The EPA requests comment on whether

[462] *GHG Mitigation Measures – 111(d)* TSD, chapters 3.2.1.4 and 3.2.2.3.

using a period of 3.5 years after state plan submission is appropriate for establishing a compliance deadline for these emission guidelines. As explained above, the EPA is basing this proposed timeframe on the expectation that some of the initial evaluation and planning steps for both natural gas co-firing and CCS would take place as part of state plan development, *i.e.*, before the state plan submission deadline. To the extent that commenters believe more or less time after state plan submission is more appropriate, the EPA requests that commenters provide information supporting the provision of a different compliance date. Additionally, the proposed state plan submission date and proposed compliance date are based on the EPA's anticipation that it will publish final emission guidelines for affected EGUs in June 2024. Should the actual date of publication of the final emission guidelines differ from this target, the EPA will adjust the state plan submission and compliance dates accordingly.

C. Requirement for State Plans to Maintain Stringency of the EPA's BSER Determination

As explained in section V.C of this preamble, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include standards of performance for existing sources. Under CAA section 111(a)(1), a standard of performance is "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated." That is, the EPA has the responsibility to determine the best system of emission reduction for a given category or subcategory of sources and to determine the degree of emission limitation achievable through application of the BSER to affected sources.[463]

[463] *See, e.g., West Virginia v. EPA*, 142 S. Ct. 2587, 2607 (2022) ("In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.") (internal citations omitted).

The level of emission performance required under CAA section 111 is reflected in the EPA's presumptive standards of performance.

States use the EPA's presumptive standards of performance as the basis for establishing requirements for affected sources in their state plans. In order for the EPA to find a state plan "satisfactory," that plan must address each affected source within the state and achieve the level of emission performance that would result if each affected source was achieving its presumptive standard of performance, after accounting for any application of RULOF.[464] That is, while states have the discretion to establish the applicable standards of performance for affected sources in their state plans, the structure and purpose of CAA section 111 require that those plans achieve equivalent stringency as applying the EPA's presumptive standards of performance to each of those sources (again, after accounting for any application of RULOF).

The EPA's December 2022 proposed revisions to the CAA section 111 implementing regulations (subpart Ba) would provide that states are permitted, in appropriate circumstances, to adopt compliance measures that allow their sources to meet their standards of performance in the aggregate.[465] As with the establishment of standards of performance for affected sources, CAA section 111 requires that state plans that include such flexibilities for complying with standards of performance demonstrate equivalent stringency as would be achieved if each affected source was achieving its standard of performance.

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[464] As explained in section XI.D.2 of this preamble, states may invoke RULOF to apply a less stringent standard of performance to a particular affected EGU when the state demonstrates that the EGU cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA. In this case, the state plan may not necessarily achieve the same stringency as achieving the EPA's presumptive standards of performance because affected EGUs for which RULOF has been invoked would have standards of performance less stringent than the EPA's presumptive standards.

[465] See 87 FR 79176, 79207–08 (December 23, 2015).

The requirement that state plans achieve equivalent stringency to the EPA's BSER and stringency determinations is borne out of the structure and purpose of CAA section 111, which is to mitigate air pollution that is reasonably anticipated to endanger public health or welfare. It achieves this purpose by requiring source categories that cause or contribute to dangerous air pollution to operate more cleanly. Unlike the Clean Air Act's NAAQS-based programs, section 111 is not designed to reach a level of emissions that has been deemed "safe" or "acceptable"; there is no air-quality target that tells states and sources when emissions have been reduced "enough." Rather, CAA section 111 requires affected sources to reduce their emissions to the level that the EPA has determined is achievable through application of the best system of emission reduction, *i.e.*, to achieve emission reductions consistent with the applicable presumptive standard of performance. Consistent with the statutory purpose of requiring affected sources to operate more cleanly, the EPA typically expresses presumptive standards of performance as rate-based emission limitations.

In the course of complying with a rate-based standard of performance under a state plan, an affected source may take an action that removes it from the source category, *e.g.*, by permanently ceasing operations. In this case, the source is no longer subject to the emission guidelines. An affected source may also choose to change its operating characteristics in a way that impacts its overall emissions, *e.g.*, by changing its utilization; however, the source is still required to meet its rate-based standard. In either instance, the changes to one affected source do not implicate the obligations of other affected sources. Although such changes may reduce emissions from the source category, they do not absolve the remaining affected EGUs from the statutory obligation to improve their emission performance consistent with the level that the EPA has determined is achievable through application of the BSER. This fundamental statutory requirement applies regardless of whether a standard of performance is expressed or implemented as a rate- or mass-based emission limitation, or whether standards of performance are achieved on a source-specific or aggregate basis.

In sum, consistent with the respective roles of the EPA and states under CAA section 111, states have discretion to establish standards of performance for affected sources in their state plans, and to provide flexibilities for affected sources to use in complying with those standards. However, state plans must demonstrate that they ultimately provide for equivalent stringency as would be achieved if each affected source was achieving the applicable presumptive standard of performance, after accounting for any application of RULOF.

D. Establishing Standards of Performance

CAA section 111(d)(1)(A) provides that "each State shall submit to the Administrator a plan which establishes standards of performance for any existing source"; that plan must also "provide[] for the implementation and enforcement of such standards of performance." That is, states must use the BSER and stringency in the EPA's emission guidelines to establish standards of performance for each existing affected EGU (as defined in section IX of this preamble) through a state plan.

To assist states in developing state plans that achieve the level of stringency required by the statute, it has been the EPA's longstanding practice to provide presumptively approvable standards of performance or a methodology for establishing such standards. For the purpose of these emission guidelines, the EPA is proposing a methodology for states to use in establishing presumptively approvable standards of performance for affected EGUs. Per CAA section 111(a)(1), the basis of this methodology is the degree of emission limitation the EPA has determined is achievable through application of the BSER to each subcategory. The EPA anticipates and intends for most states to apply the presumptive standards of performance to affected EGUs.

Additionally, CAA section 111(d)(1)(B) permits states to take into consideration a particular affected EGU's RULOF when applying a standard of performance to that source. The EPA's proposed revisions to the CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba provide that a state would be able to apply a less stringent standard of performance to an affected EGU when the state can demonstrate that the source cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA. Proposed subpart Ba describes the conditions that would warrant application of a less stringent RULOF standard under these emission guidelines and how a RULOF standard would be determined. Further detail about how the EPA proposes to implement the RULOF provision in the context of this rulemaking is provided in section XI.D.2 of this preamble.

States also have the authority to apply standards of performance to affected EGUs that are more stringent than the EPA's presumptively approvable standards of performance.[466]

1. Application of Presumptive Standards

As described in section X.C of this preamble, the EPA is proposing to first subcategorize the affected EGUs under these emission guidelines by fuel type: coal-fired and oil- or natural gas-fired steam generating units. The EPA is proposing further subcategorization into four subcategories for coal-fired steam generating units and seven subcategories for oil- and natural gas-fired steam generating units. Under this proposal, each subcategory with a proposed BSER and degree of emission limitation would have a corresponding methodology for establishing

[466] 40 CFR 60.24a(f). The EPA has proposed to revise this provision to clarify that it has the obligation and authority to review and approve state plans that contain the more stringent requirements. See 87 FR 79176, 79204 (December 23, 2022).

presumptively approvable standards of performance (also referred to as "presumptive standards of performance" or "presumptive standards"). As explained in section X.C.3, the EPA is proposing that an affected coal-fired steam EGU's operating horizon determines the applicable subcategory in three of the four subcategories; in the case of the near-term subcategory, the operating horizon and load level establish applicability. For affected oil- and natural gas-fired steam generating units, subcategories are defined by load level and the type of fuel fired, as well as locality (*i.e.*, continental and non-continental U.S.). There are four subcategories for oil-fired steam generating units based on different combinations of load level (base load, intermediate load, and low load) and locality, and three subcategories for natural gas-fired steam generating units based on load level (base load, intermediate, and low).

A state, when establishing standards of performance for affected EGUs in its plan, would identify each affected EGU in the state and specify into which subcategory each EGU falls. The EPA is proposing that the state would then use the corresponding methodology for the given subcategory to calculate and apply the presumptively approvable standard of performance for each affected EGU.

The EPA notes that, as explained in section X.C.3 of this preamble, commitments for dates to permanently cease operation and capacity factor commitments on which a state relies to subcategorize coal-fired steam generating units under these emission guidelines will become federally enforceable upon EPA approval of a state plan including those commitments. While such commitments must be enforceable by the state when its plan is submitted to the EPA, they do not necessarily have to be federally enforceable at that time. However, this preamble uses the term "federally enforceable commitment" throughout to make clear that date and capacity factor commitments contained in a state plan will become federally enforceable upon EPA approval of that plan.

States also have the authority to deviate from the methodology for presumptively approvable standards, in order to apply a more stringent standard of performance through increasing the degree of emission limitation beyond what the EPA has determined to be achievable for units as a general matter (*e.g.,* a state decides that an EGU in the medium-term coal-fired subcategory should co-fire 50 percent natural gas instead of 40 percent). Deviations to increase stringency do not trigger use of the RULOF mechanism, which requires states to demonstrate that an affected EGU cannot reasonably apply the BSER to achieve the degree of emission limitation determination by the EPA.[467] The EPA proposes to presume that standards of performance that are more stringent than the EPA's presumptive standards are "satisfactory" for the purposes of CAA section 111(d).

a. Establishing Baseline Emission Performance for Presumptive Standards

For each of the coal-fired subcategories and for the non-continental intermediate and base load oil-fired subcategory, the proposed methodology to calculate a standard of performance entails establishing a baseline of CO_2 emissions and corresponding electricity generation for an affected EGU and then applying the degree of emission limitation achievable through the application of the BSER (as established in section X.D of this preamble). The methodology for establishing baseline emission performance for an affected EGU is identical in each of the subcategories but will result in a value that is unique to each affected EGU. To establish baseline emission performance for an affected EGU, the EPA is proposing that a state will use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any

[467] See 87 FR 79176, 79199 (December 23, 2022).

continuous 8-quarter period from 40 CFR part 75 reporting within the 5 years immediately prior to the date the final rule is published in the *Federal Register*. This proposed period is based on the NSR program's definition of "baseline actual emissions" for existing electric steam generating units. See 40 CFR 52.21(b)(48)(i). Eight quarters of 40 CFR part 75 data corresponds to a 2-year period, but the EPA is proposing 8 quarters of data as that corresponds to quarterly reporting according to 40 CFR part 75. Functionally, the EPA expects states to utilize the most representative 8-quarter period of data from the 5 years immediately preceding the date the final rule is published in the *Federal Register*. For the 8 quarters of data, the EPA is proposing that a state would divide the total CO_2 emissions (in the form of pounds) over that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh. As an example, a state establishing baseline emission performance in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for each of its affected EGUs for 2018 through 2022 and choosing, for each affected EGU, a continuous 8-quarter period that it deems to be the best representation of the operation of that affected EGU. While the EPA will evaluate the choice of baseline periods chosen by states when reviewing state plan submissions, the EPA intends to defer to a state's reasonable exercise of discretion as to which 8-quarter period is representative.

The EPA is proposing to require the use of 8 quarters during the 5-year period prior to the date the final rule is published in the *Federal Register* as the relevant period for the baseline methodology for a few reasons. First, each affected EGU has unique operational characteristics that affect the emission performance of the EGU (load, geographic location, hours of operation, coal rank, unit size, *etc.*), and the EPA believes each affected EGU's emission performance baseline should be representative of the source-specific conditions of the affected EGU and how it has typically operated. Additionally, allowing a state to choose (likely in consultation with the owners or operators of affected EGUs) the 8-quarter period for assessing baseline performance can avoid situations in which a prolonged period of atypical operating conditions would otherwise skew the emissions baseline. Relatedly, the EPA believes that by using total mass CO_2 emissions and total electric generation for an affected EGU over an 8-quarter period, any relatively short-term variability of data due to seasonal operations or periods of startup and shutdown, or other anomalous conditions, will be averaged into the calculated level of baseline emission performance. The baseline-setting approach of using total CO_2 mass emissions and total electric generation over an 8-quarter period also aligns with the reporting and compliance requirements. The EPA is proposing that compliance would be demonstrated annually based on the lb CO_2/MWh emission rate derived by dividing the total reported CO_2 mass emissions by the total reported electric generation for an affected EGU during the compliance year, which is consistent with the expression of the degree of emission limitation proposed for each subcategory in sections X.D.4 and X.E.2. The EPA believes that using total mass CO_2 emissions and total electric generation provides a simple and streamlined approach for calculating baseline emission performance without the need to sort and filter non-representative data; any minor amount of non-representative data will be subsumed and accounted for through implicit averaging over the course of the 8-quarter period. Moreover, this approach, by not sorting or filtering the data, eliminates any need for discretion in assessing whether the data is appropriate to use.

The EPA is soliciting comment on the proposed baseline-setting approach and specifically on the applicability of such an approach for each of the different subcategories. The EPA is proposing a continuous 8-quarter period to better average out operating variability but solicits comment on whether a different time period would be more appropriate for assessing baseline emission performance, as well as on the 5-year window from which the period for baseline emission performance is chosen. The EPA also solicits comment on the use of total mass CO_2 emissions and total electric generation over a consecutive 8-quarter time period as representative and on whether the EPA's proposed approach is appropriate.

The EPA believes that using the proposed baseline-setting approach as the basis for establishing presumptively approvable standards of performance will provide certainty for states, as well as transparency and a streamlined process for state plan development. While this approach is specifically designed to be flexible enough to accommodate unit-specific circumstances, states retain the ability to deviate from the methodologies the EPA is proposing for establishing baselines of emission performance for affected EGUs. The EPA believes that the instances in which a state may need to use an alternate baseline-setting methodology will be limited to anticipated changes in operation, *i.e.*, circumstances in which historical emission performance is not representative of future emission performance. The EPA is proposing that states wishing to vary the baseline calculation for an affected EGU based on anticipated changes in operation, when those changes result in a less stringent standard of performance, must use the RULOF mechanism, which is designed to address such contingencies.

b. Long-term Coal-fired Steam Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for long-term coal-fired steam generating units. Affected EGUs that choose to adopt a federally enforceable commitment to permanently cease operations of January 1, 2040, or later, or that do not adopt a federally enforceable date to permanently cease operations included in the state's plan submission, fall within this subcategory and have a proposed BSER of CCS with 90 percent capture and a proposed degree of emission limitation of 90 percent capture of the mass of CO_2 in the flue gas (*i.e.*, the mass of CO_2 after the boiler but before the capture equipment) over an extended period of time and an 88.4 percent reduction in emission rate on a gross basis over an extended period of time. The EPA is proposing that where states use the methodology described here to establish standards of performance for an affected EGU in this subcategory, those established standards would be presumptively approvable when included in a state plan submission. In section X of this preamble, for the long-term coal-fired subcategory, the EPA is soliciting comment on a capture rate of 90 to 95 percent and a degree of emission limitation defined by a reduction in emission rate on a gross basis from 75 to 90 percent.

Establishing a standard of performance for an affected coal-fired EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described above); and applying the level of stringency, based on the application of the BSER, to that level of baseline emission performance. Implementation of CCS with a capture rate of 90 precent translates to a level of stringency of an 88.4 percent reduction in CO_2 emission rate (see section X.D.4.a of this preamble) compared to the baseline level of emission performance. Using the complement of 88.4 percent (*i.e*., 11.6 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance. For example, if a long-term coal-fired EGU's level of baseline emission performance is 2,000 lbs per MWh, it will have a presumptively approvable standard of performance of 232 lbs per MWh (2,000 lbs per MWh multiplied by 0.116).

The EPA is also proposing that affected coal-fired EGUs in the long-term subcategory comply with federally enforceable increments of progress, which are described in section XI.D.3.a of this preamble.

The EPA solicits comments on this proposed methodology for calculating presumptively approvable standards of performance for long-term coal-fired steam generating units.

c. Medium-term Coal-fired Steam Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for medium-term coal-fired steam generating units. Affected EGUs that choose to adopt a federally enforceable commitment to permanently cease operations after December 31, 2031, and before January 1, 2040, have a proposed BSER of 40 percent co-firing of natural gas. The EPA is proposing that where states use the methodology described here to establish standards of performance for affected coal-fired EGUs in this subcategory, those established standards of performance would be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described earlier in this preamble); and applying the level of emission reduction stringency, based on the application of the BSER, to that level of baseline emission performance. Implementation of natural gas co-firing at a level of 40 percent of total annual heat input translates to a level of stringency of a 16 percent reduction in CO_2 emissions (see section X.D.4.b of this preamble) compared to the baseline level of emission performance. Using the complement of 16 percent (*i.e.*, 84 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance for the affected EGU. For example, if a medium-term coal-fired EGU's level of baseline emission performance is 2,000 lbs per MWh, it will have a presumptively approvable standard of performance of 1,680 lbs per MWh (2,000 lbs per MWh multiplied by 0.84). In section X of this preamble, for the medium-term coal-fired subcategory, the EPA is soliciting comment on a natural gas co-firing level of 30 to 50 percent and a degree of emission limitation from 12 to 20 percent.

For medium-term coal-fired steam generating units that have an amount of co-firing that is reflected in the baseline operation, the EPA is proposing that states account for such preexisting co-firing in adjusting the degree of emission limitation. If, for example, an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 30 percent to reflect the preexisting level of natural gas co-firing. This results in a standard of performance based on the degree of emission limitation achieving an additional 30 percent co-firing beyond the 10 percent that is accounted for in the baseline. The EPA believes this approach is a more straightforward mathematical adjustment than adjusting the baseline to appropriately reflect a preexisting level of co-firing. However, the EPA solicits comment on whether the adjustment of a standard of performance based on preexisting levels of natural gas co-firing should be done through the baseline. To adjust the baseline to account for preexisting natural gas co-firing, the state would need to calculate a baseline of emission performance for an EGU that removes the mass emissions and electric generation that are attributable to the natural gas portion of the fuel. With this adjusted baseline that removes the natural gas-fired portion, the presumptive standard of performance would be calculated by multiplying the adjusted baseline by the degree of emission limitation factor that reflects 40 percent co-firing. The EPA is not proposing this methodology, because parsing the attributable emissions and electric generation associated with natural gas co-firing from the attributable emissions and electric generation associated with coal-fired generation requires manipulation of the emissions and electric generation data. However, the EPA solicits comment on whether baseline adjustment is more appropriate and also why that may be so.

The standard of performance for the medium-term coal-fired subcategory is based on the degree of emission limitation that is achievable through application of the BSER to the affected EGUs in the subcategory and consists exclusively of the rate-based emission limitation. However, to qualify for inclusion in the subcategory an affected coal-fired EGU must have chosen to commit to permanently cease operations prior to January 1, 2040. This date will be included in a state's plan submission and, if approved by the EPA, will become a federally enforceable component of the state plan.

The EPA is proposing that affected coal-fired EGUs that are required to have enforceable dates to permanently cease operations for subcategory applicability, including EGUs in the medium-term coal-fired subcategory, have corresponding federally enforceable milestones with which they must comply. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with their state plan and commitments to dates to permanently cease operations. These milestones are described in detail in section XI.D.3.b of this preamble. Affected EGUs in this subcategory would also be required to comply with the federally enforceable increments of progress described in section XI.D.3.a of this preamble.

The EPA solicits comment on the proposed methodology for calculating presumptively approvable standards of performance for medium-term coal-fired steam generating units, including on the proposed approach for adjusting a presumptively approvable standard of performance to accommodate preexisting natural gas co-firing.

d. Imminent-term Coal-fired Steam Generating Units

This section describes the EPA's proposed methodology for establishing presumptively approvable standards of performance for imminent-term coal-fired steam generating units. Affected EGUs that choose to adopt a federally enforceable commitment to permanently cease operations before January 1, 2032, have a proposed BSER of routine methods of operation and maintenance. Therefore, the proposed presumptively approvable standard of performance is based on the baseline emission performance of the affected EGU (as described in section XI.D.1.a of this preamble).

Unlike the proposed standards of performance for the long-term and medium-term coal-fired steam generating units, establishing a standard of performance for an affected EGU in the imminent-term subcategory consists of just one step. The EPA is proposing that where states use the methodology described in section XI.D.1.a of this preamble to establish the baseline level of emission performance for an affected EGU, the emission rate described by that baseline would constitute the presumptively approvable standard of performance. This standard of performance reflects that the proposed BSER for these affected EGUs is routine methods of operation and maintenance and a degree of emission limitation equivalent to no increase in emission rate from the baseline level of emission performance. This also ensures that the affected EGU will not backslide in its emission performance.

Although the EPA believes that the baseline performance level adequately accounts for variability in annual emission rate, the EPA is also soliciting comment on a methodology for a presumptive standard above the baseline emission performance. For the imminent-term coal-fired subcategory, the EPA is soliciting comment on a presumptive standard that is defined by 0 to 2 standard deviations in annual emission rate (using the 5-year period of data) above the baseline emission performance, or that is 0 to 10 percent above the baseline emission performance.

The standard of performance for the imminent-term coal-fired subcategory is based on the degree of emission limitation that is achievable through application of the BSER to the affected EGUs in the subcategory and consists exclusively of the rate-based emission limitation. However, to qualify for inclusion in the subcategory an affected coal-fired EGU must have chosen to commit to permanently cease operations prior to January 1, 2032. This date will be included in a state's plan submission and, if approved by the EPA, will become a federally enforceable component of the state plan.

The EPA is also proposing that affected coal-fired EGUs that are required to have enforceable dates to permanently cease operations for subcategory applicability, including EGUs in the imminent-term coal-fired subcategory, have corresponding federally enforceable milestones with which they must comply. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with these dates in their state plan. These milestones are described in detail in section XI.D.3.b of this preamble.

The EPA solicits comment on the proposed methodology for establishing presumptively approvable standards of performance for imminent-term coal-fired steam generating units.

e. Near-term Coal-fired Steam Generating Units

Similar to the proposed approach for establishing presumptively approvable standards of performance for affected EGUs in the imminent-term coal-fired subcategory, the EPA is proposing that affected EGUs in the near-term coal-fired subcategory have a presumptively approvable standard of performance based on the baseline emission performance of the affected EGU (as described in section XI.D.1.a of this preamble). The near-term subcategory includes affected EGUs that choose to adopt a federally enforceable commitment to permanently cease operations after December 31, 2031, and before January 1, 2035, and that choose to make a federally enforceable commitment to operate with an annual capacity factor of less than 20 percent.

The EPA is proposing that where states use the methodology described in section XI.D.1.a of this preamble to establish the baseline level of emission performance for an affected EGU, the emission rate described by that baseline would constitute the presumptively approvable standard of performance. This standard of performance reflects the proposed BSER of routine methods of operation and maintenance and a degree of emission limitation equivalent to no increase in emission rate. This also ensures that the affected EGU will not backslide in its emission performance.

For the near-term coal-fired subcategory, the EPA is soliciting comment on a presumptive standard that is defined by 0 to 2 standard deviations in annual emission rate (using the 5-year period of data) above the baseline emission performance, or that is 0 to 10 percent above the baseline emission performance.

The standard of performance for the near-term coal-fired subcategory is based on the degree of emission limitation that is achievable through application of the BSER to the affected EGUs in the subcategory and consists exclusively of the rate-based emission limitation. However, to qualify for inclusion in the subcategory an affected coal-fired EGU must have chosen to commit to permanently cease operations after December 31, 2031, and before January 1, 2035, and must have chosen to commit to operate at an annual capacity factor of less than 20 percent. These commitments will be included in a state's plan submission and, if approved by the EPA, will become a federally enforceable component of the state plan.

The EPA is also proposing that affected coal-fired EGUs that are required to have enforceable dates to permanently cease operations for subcategory applicability, including EGUs in the near-term coal-fired subcategory, have corresponding federally enforceable milestones with which they must comply. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with these dates in their state plan . These milestones are described in detail in section XI.D.3.b of this preamble.

The EPA solicits comment on the proposed methodology for establishing presumptively approvable standards of performance for near-term coal-fired steam generating units.

f. Natural Gas-fired Steam Generating Units and Continental Oil-fired Steam Generating Units

This section describes the EPA's proposed methodology for presumptively approvable standards of performance for affected natural gas-fired and continental oil-fired steam generating units: low load natural gas-fired steam generating units, intermediate load natural gas- fired steam generating units, base load natural gas-fired steam generating units, low load oil-fired steam generating units, intermediate load continental oil-fired steam generating units, and base load continental oil-fired steam generating units. It does not address non-continental intermediate oil-fired and non-continental base load oil-fired steam generating units, which are described in section XI.D.1.f of this preamble. The proposed definitions of these subcategories are discussed in section X.C.2 of this preamble. The proposed presumptive standards of performance are based on degrees of emission limitation that units are currently achieving, consistent with the proposed BSER of routine methods of operation and maintenance, which amounts to a proposed degree of emission limitation of no increase in emission rate.

Unlike the approach to establishing presumptive standards of performance for coal-fired EGUs in these proposed emission guidelines, the EPA is proposing presumptive standards of performance for affected natural gas-fired and continental oil-fired steam generating units in lieu of methodologies that states would use to establish presumptive standards of performance. This is largely because the low variability in emissions data at intermediate and base load for these units and relatively consistent performance between these units at those load levels, as discussed in section X.E of this preamble and detailed in the *Natural Gas- and Oil-fired Steam Generating Unit* TSD, allows for the identification of a generally applicable emission standard.

However, for natural gas- or oil-fired units with low annual capacity factors, annual emission rates can be high (greater than 2,500 lb CO_2/MWh-gross) and can vary considerably across units and from year to year. Despite their relatively high emission rates, though, overall emissions from these units are low. Based on these considerations, the EPA is not proposing a BSER or that states establish standards of performance for these units at this time. However, as noted above, the EPA is soliciting comment on determining a BSER of clean fuels for these units. In addition, the EPA is soliciting comment on a presumptive standard of performance for these units based on heat input. Specifically, the EPA is soliciting comment on a range of presumptive standards of performance from 120 to 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units, and from 160 to 170 lb CO_2/MMBtu for low load oil-fired steam generating units.

For intermediate load natural gas-fired units (annual capacity factors greater than or equal to 8 percent and less than 45 percent), annual emission rates are less than 1,500 lb CO_2/MWh-gross for about 90 percent of the units. Therefore, the EPA is proposing the presumptive standard of performance of an annual calendar-year emission rate of 1,500 lb CO_2/MWh-gross for these units.

For base load natural gas-fired units (annual capacity factors greater than or equal to 45 percent), annual emission rates are less than 1,300 lb CO_2/MWh-gross for about 80 percent of units. Therefore, the EPA is proposing the presumptive standard of performance of an annual calendar-year emission rate of 1,300 lb CO_2/MWh-gross for these units.

In the continental U.S., there are few if any oil-fired steam generating units that operate with intermediate or high utilization. Liquid-oil-fired steam generating units with 24-month capacity factors less than 8 percent do qualify for a work practice standard in lieu of emission requirements under the Mercury and Air Toxics Standards rule (MATS) (40 CFR 63, subpart UUUUU). If oil-fired units operated at higher annual capacities, it is likely they would do so with substantial amounts of natural gas firing and have emission rates that are similar to steam generating units that fire only natural gas at those levels of utilization. There are a few natural gas-fired steam generating units that are near the threshold for qualifying as oil-fired units (*i.e.*, firing more than 15 percent oil in a given year) but that on average fire more than 90 percent of their heat input from natural gas. Therefore, the EPA is proposing the same presumptive standards of performance for oil-fired steam generating units as for natural gas-fired units, noted above.

The EPA is also taking comment on a range of presumptive standards of performance for natural gas- and oil-fired steam generating units. Specifically, the EPA is soliciting comment on standards between (i) 1,400 and 1,600 lb CO_2/MWh-gross for intermediate load natural gas-fired units, (ii) 1,250 and 1,400 lb CO_2/MWh-gross for base load natural gas-fired units, (iii) 1,400 and 2,000 lb CO_2/MWh-gross for intermediate load oil-fired units, and (iv) 1,250 and 1,800 lb CO_2/MWh-gross for base load oil-fired units. The upper end of the ranges for oil-fired units is higher because of the limited data available for oil-fired units that operate at those annual capacity factors.

g. Non-continental Oil-fired Steam Generating Units

The EPA is proposing that for affected EGUs in the non-continental intermediate oil-fired and non-continental base load oil-fired subcategory, a presumptively approvable standard of performance would be based on baseline emission performance, consistent with the EPA's proposed BSER determination of routine methods of operation and maintenance and the proposed degree of emission limitation of no increase in emission rate. The EPA is proposing that where states use the methodology described in section XI.D.1.a of the preamble to establish unit-specific baseline levels of emission performance for affected EGUs in this subcategory, those emission rates would constitute presumptively approvable standards of performance when included in a state plan submission. This standard of performance would ensure no increase in the unit-specific emission rate from the baseline level of emission performance.

For the intermediate and base load non-continental oil-fired subcategory, the EPA is soliciting comment on a presumptive standard that is defined by 0 to 2 standard deviations in annual emission rate (using the 5-year period of data) above the baseline emission performance, or that is 0 to 10 percent above the baseline emission performance.

The EPA solicits comment on the proposed methodology for establishing presumptively approvable standards of performance for non-continental oil-fired steam generating units in the intermediate and base load subcategories.

2. Remaining Useful Life and Other Factors

Under CAA section 111(d), the EPA is required to promulgate regulations under which states submit plans applying standards of performance to affected EGUs. While states establish the standards of performance, there is a fundamental obligation under CAA section 111(d) that such standards reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA.[468] The EPA identifies this degree of emission limitation as part of its emission guideline. 40 CFR 60.22a(b)(5). Thus, as described in section X.D of this preamble, the EPA is providing proposed methodologies for states to follow in determining and applying presumptively approvable standards of performance to affected EGUs in each of the subcategories covered by these emission guidelines.

While standards of performance must generally reflect the degree of emission limitation achievable through application of the BSER, CAA section 111(d)(1) also requires that the EPA regulations permit the states, in applying a standard of performance to a particular designated facility, to “take into consideration, among other factors, the remaining useful life of the existing sources to which the standard applies.” The EPA’s implementing regulations under 40 CFR 60.24a thus allow a state to consider a particular designated facility’s remaining useful life and other factors in applying to that facility a standard of performance that is less stringent than the presumptive level of stringency given in an emission guideline.

In December 2022, the EPA proposed to clarify the existing requirements in subpart Ba governing what a state must demonstrate in order to invoke RULOF and provide a less stringent standard of performance when submitting a state plan.[469] Specifically, the EPA proposed to require the state to demonstrate that a particular facility cannot reasonably achieve the degree of

[468] *West Virginia v. EPA*, 142 S. Ct. 2587, 2607 (2022) (“In devising emissions limits for power plants, EPA first ‘determines’ the ‘best system of emission reduction’ that—taking into account cost, health, and other factors—it finds ‘has been adequately demonstrated.’ The Agency then quantifies ‘the degree of emission limitation achievable’ if that best system were applied to the covered source.”) (internal citations omitted).
[469] See 87 FR 79176, 79196–79206 (December 23, 2022).

emission limitation achievable through application of the BSER based on one or more of three delineated circumstances, and proposed to clarify those three circumstances. The EPA also proposed additions and further clarifications to the process of invoking RULOF and determining a standard of performance based on RULOF, to ensure that use of the provision does not undermine the overall presumptive level of stringency of the BSER, as well as to provide a clear analytical framework for states and the regulated community as they seek to craft satisfactory plans that the EPA can ultimately approve.[470]

The EPA is not soliciting comment in this rulemaking on the proposed revisions to the RULOF provisions in subpart Ba, which are subject to a separate rulemaking process. As noted in section XI.A of this preamble, the EPA intends to finalize revisions to subpart Ba prior to finalizing these emission guidelines. Those revised RULOF provisions, including any changes made in response to public comments, will apply to these emission guidelines. While the EPA is not taking comment on the proposed provisions of subpart Ba themselves, the EPA is requesting comment on how each of the RULOF provisions that the EPA proposed in December 2022 would be implemented in the context of these particular emission guidelines.

The remainder of this section of the preamble addresses how the requirements associated with RULOF, as the EPA has proposed to revise them, would apply to states and state plans under these emission guidelines. First, it addresses the threshold requirements for considering RULOF and how those requirements would apply to an affected EGU under these emission guidelines. Second, it addresses how, if a state has appropriately invoked RULOF for a particular affected EGU under the previous step, it would be required to determine a source-specific BSER and calculate a standard of performance for that affected EGU. Third, it discusses the proposed

[470] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002.

requirement for plans that apply less stringent standards of performance pursuant to RULOF to consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the affected EGU. Fourth, this section addresses the proposed provisions for the standard for EPA review of state plans that include RULOF standards of performance. And, finally, it discusses the EPA's proposed interpretation of the Clean Air Act as laid out in the proposed revisions to subpart Ba that the Act allows states to adopt and enforce standards of performance more stringent than required by an applicable emission guideline, and that the EPA has the ability and authority to approve such standards of performance into state plans.

a. Threshold Requirements for Considering RULOF

As discussed earlier in this preamble, CAA section 111(d)(1) expressly requires the EPA to permit states to consider RULOF when applying a standard of performance to a particular affected EGU. The EPA's proposed revisions to the regulations governing states' use of RULOF would provide a clear analytical framework to ensure that its use to apply less stringent standards of performance for particular sources is consistent across states. The proposed revisions would also ensure that the use of the RULOF framework does not undermine the overall presumptive level of stringency of the EPA's BSER determination or render it meaningless. Such a result would be contrary to the overarching purpose of CAA section 111(d), which is generally to achieve meaningful emission reductions from designated facilities, in this case affected EGUs, based on the BSER in order to mitigate pollution that endangers public health and welfare.

To this end, proposed subpart Ba would provide that a state may apply a less stringent standard of performance to a particular facility, taking into consideration remaining useful life and other factors, provided that the state demonstrates with respect to that facility (or class of facilities) that it cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA. Invocation of RULOF would be required to be based on one or more of three circumstances: (1) unreasonable cost of control resulting from plant age, location, or basic process design, (2) physical impossibility or technical infeasibility of installing necessary control equipment, or (3) other circumstances specific to the facility that are fundamentally different from the information considered in the determination of the BSER in the emission guidelines.[471]

A state wishing to invoke RULOF in order to apply a less stringent standard to a particular affected EGU would be required to demonstrate that there are fundamental differences between that EGU and the EPA's BSER determination, based on consideration of the BSER factors that the EPA considered in its analysis. In determining the BSER and the degree of emission reductions achievable through application of the BSER in these proposed emission guidelines, the EPA considered whether a system of emission reduction is adequately demonstrated for the subcategory based on the physical possibility and technical feasibility of applying that system, the costs of a system of emission reduction, the non-air quality health and environmental impacts and energy requirements associated with a system of emission reduction, and the extent of emission reductions from a system.[472]

For each subcategory, the EPA evaluated certain metrics related to each of these BSER factors. For example,[473] in evaluating the costs associated with CCS and natural gas co-firing,

[471] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (containing proposed revisions to RULOF provisions at 40 CFR 60.24a(e)–(n)).
[472] The EPA also considered impacts on the energy sector as part of its BSER determinations. However, because this consideration does not apply at the level of a particular affected EGU, it would not be appropriate basis for invoking RULOF.
[473] The examples are only for illustrative purposes and should not be interpreted to represent the difference that must exist to demonstrate a fundamental difference between the EPA's BSER determination and a particular affected EGU's circumstances.

the EPA considered both $/ton CO_2 reduced and increases in levelized costs expressed as dollars per MWh electricity generation. For long-term coal-fired steam generating units, the EPA assessed the cost of CCS under a range of scenarios varying the amortization period and capacity factor. In section X.D.1.a.ii of this preamble, the EPA discusses various representative scenarios under which it is proposing to find that the costs of CCS are reasonable. For example, the EPA is proposing that a cost of $12/MWh for a reference unit with 50 percent capacity factor and an amortization period of 12 years is reasonable, but notes that a cost of $34/MWh for reference unit with a 7-year amortization period at a 70 percent capacity factor is less favorable. A state wishing to invoke RULOF for a particular affected EGU in the long-term coal-fired subcategory based on unreasonable cost of control would also be required to consider the cost per ton of CO_2 reduced and cost per MWh electricity generated. The state would further have to demonstrate that the costs, as represented by these two metrics, for the particular affected EGU are significantly higher than the costs the EPA determines to be reasonable due to that EGU's age, location, or basic process design.

The RULOF provision, currently and as the EPA has proposed to revise it, also allows states to invoke RULOF based on other circumstances specific to an affected EGU. As an illustrative example, a state may wish to invoke RULOF for a medium-term coal-fired steam generating unit that is extremely isolated (*e.g.*, on a small island more than 200 miles offshore) such that it would require construction of an LNG terminal and shipping of LNG by barge to have natural gas available to fire at the unit. In the EPA's evaluation of natural gas co-firing as the potential BSER for medium-term coal-fired steam generating units, the EPA considered the distance and cost of lateral pipeline builds in proposing natural gas co-firing as BSER. If a state can demonstrate that there is something unique to the source's being on a remote island, that this was not considered in evaluation of the BSER, and that the affected EGU cannot otherwise reasonably achieve the standard of performance, then it may be reasonable to invoke RULOF for that source.

Under the EPA's proposed approach, states would not be able to invoke RULOF based on minor, non-fundamental differences between a particular affected EGU and what the EPA determined was reasonable for the BSER. There could be instances in which an affected EGU may not be able to comply with the presumptively approvable standard of performance based on the precise metrics of the BSER determination but is able to do so within a reasonable margin.

The EPA is providing a range of cost evaluations based on different assumptions regarding amortization period and capacity factor, and is proposing to find that the costs of CCS and natural gas co-firing are reasonable for long-term and medium-term coal-fired steam generating units, respectively, under the range of relevant scenarios. For example, the costs of CCS for a particular affected EGU with an amortization period of 12 years and a 50 percent capacity factor may be $18/MWh, which is higher than the $12/MWh that the EPA determined for a reference unit and the $7/MWh that EPA determined was the average cost for the fleet. However, $18/MWh is not an unreasonable cost given, *e.g.*, costs the EPA has determined are reasonable under other scenarios in this proposed rule and the comparisons to the costs of other rules that the EPA discussed in section X.D.1.a.ii of this preamble. A cost of $18/MWh would therefore not constitute a fundamental difference between the EPA's BSER determination and the circumstances of the affected EGU and would not be a reasonable basis for invoking RULOF. On the other hand, costs that constitute outliers, *e.g.*, that are greater than the 95th percentile of costs on a fleetwide basis for comparable circumstances or that are the same as costs the EPA has determined are unreasonable elsewhere under these emission guidelines would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF.

Importantly, the costs evaluated in the BSER determination are, in general, for representative, average units or are based on average values across the fleet of steam generating units. Those BSER cost analysis values represent the average of a distribution of costs including costs that are above or below the average representative value. On that basis, implicit in the proposed determination that those average representative values are reasonable is a proposed determination that a significant portion of the unit specific costs around those average representative values are also reasonable, including some portion of those unit specific costs that are above but not significantly different than the average representative values.

Another example of a fundamental difference between the EPA's BSER determination and a particular affected EGU's circumstances is a difference based on physical impossibility or technical infeasibility. In making BSER determinations, the EPA must find that a system is adequately demonstrated; among other things, this means that the BSER must be technically feasible for the source category. For long-term coal-fired steam generating units, the EPA determined that CCS is adequately demonstrated because its components can be and have been applied to the source category and because it is generally geographically available to affected EGUs. However, it may be possible that a particular affected coal-fired EGU is physically unable to implement CCS due to, *e.g.*, the impossibility of constructing a pipeline for CO_2 transport. If a state can demonstrate that it is physically impossible or technically infeasible for this affected EGU to apply CCS because there are no other options to transport captured CO_2, there is a fundamental difference between the EPA's BSER determination and the circumstances of this particular affected EGU and the state may invoke RULOF.

The EPA has proposed that states may invoke RULOF if they can demonstrate that an affected EGU cannot apply the BSER to achieve the degree of emission limitation determined by the EPA based on one or more of the three circumstances discussed earlier in this preamble.[474] It thus follows that states would be able to invoke RULOF if they can demonstrate that an affected EGU can apply the BSER but cannot achieve the degree of emission limitation that the EPA determined is possible for the source category generally.

However, the EPA has proposed in 40 CFR part 60, subpart Ba[475] that a state may not invoke RULOF to provide a less stringent standard of performance for a particular affected EGU if that EGU cannot apply the BSER but can reasonably implement a different system of emission reduction to achieve the degree of emission limitation required by the EPA's BSER determination. While a state may be able to demonstrate that the affected EGU cannot reasonably apply the BSER based on one of the three circumstances, it would be inappropriate to invoke RULOF to apply a less stringent standard of performance because the source can still reasonably achieve the presumptive degree of emission limitation. In this instance, providing a less stringent standard of performance would be inconsistent with the purpose of CAA section 111(d) and these emission guidelines.

States' consideration of the remaining useful life of a particular source for affected coal-fired EGUs will also be informed by the structure of the EPA's proposed subcategories, each of which has its own BSER determination under these emission guidelines. Under CAA section 111(d)(1) and the EPA's proposed RULOF provisions, states may consider an affected EGU's

[474] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)).
[475] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(g)).

remaining useful life in determining whether application of the BSER to achieve the presumptive level of stringency would result in unreasonable cost resulting from plant age.[476] In determining the BSER, the EPA considers costs and, in many instances, specifically considers annualized costs associated with payment of the total capital investment of the technology associated with the BSER. However, plant age can have considerable variability within a source category and the annualized costs can change significantly based on an affected EGU's remaining useful life and associated length of the capital recovery period. Thus, the costs of applying the BSER to an affected EGU with a short remaining life may differ fundamentally from the costs that the EPA found were reasonable in making its BSER determination.

These proposed emission guidelines include BSER determinations and presumptive standards of performance for affected coal-fired EGUs in four subcategories: imminent-term, near-term, medium-term, and long-term. As explained in section X.C.3 of this preamble, these subcategories are designed to accommodate ongoing trends in the power sector, which include many coal-fired EGUs that have currently planned or announced dates to cease operations. The EPA's proposed BSER determinations for each of these subcategories, as a practical matter, already account for the remaining useful lives of the affected EGUs by amortizing costs consistent with the operating horizons of sources within each subcategory. The EPA therefore does not anticipate that states would be likely to demonstrate the need to invoke RULOF based on a particular coal-fired EGU's remaining useful life, although doing so is not prohibited under these emission guidelines. The proposed requirements for states and affected EGUs invoking RULOF based on remaining useful life are addressed in the next subsection.

[476] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)(1)).

The EPA is proposing to allow states to use the RULOF mechanism to provide a different compliance deadline for a source that can meet the presumptive standard of performance for the applicable subcategory but cannot do so by the final compliance date under these emission guidelines. In such cases, a state may be able to demonstrate that there are "other circumstances specific to the facility . . . that are fundamentally different from the information considered in the determination of the best system of emission reduction in the emission guidelines"[477] that make timely compliance impossible. However, given the relatively long lead times and compliance timeframes proposed in these emission guidelines, the EPA anticipates that these circumstances will be rare. As explained here, under the proposed revisions to subpart Ba, RULOF demonstrations, including those in support of extending a compliance deadline, would have to be based on information from reliable and adequately documented sources and be applicable to and appropriate for the affected facility.[478]

As discussed in section XI.D.1.a of this preamble, the EPA is proposing a methodology for calculating an affected EGU's baseline emissions as part of determining its presumptively approvable standard of performance. The EPA explained that while the proposed methodology should be flexible enough to accommodate most unit-specific circumstances, it may not be appropriate to use recent historical emissions data to represent baseline emission performance when an affected EGU anticipates that its future operating conditions will change significantly. Consistent with the proposed subpart Ba, the EPA is proposing that states wishing to rely on an affected EGU's anticipated change in operating conditions as the basis for using a different

[477] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)(3)).
[478] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)).

methodology to set an emissions baseline would be required to use the RULOF mechanism described in this section of the preamble.

The EPA solicits comment on the application of the RULOF provisions of proposed subpart Ba to these emission guidelines. In particular, the EPA requests comment on factual circumstances in which it may or may not be appropriate for states to invoke RULOF for affected EGUs, given the proposed requirements and the EPA's proposed "fundamental difference" standard in the subpart Ba rulemaking. For the consideration of cost, the EPA requests comment on whether it should provide further guidance or requirements for determining when the costs of a BSER technology are "fundamentally different" from the Agency's BSER determination. The EPA additionally seeks comment on any source category-specific considerations for invoking RULOF for affected EGUs, including any additional or different requirements that might be necessary to ensure that use of RULOF does not undermine the presumptive stringency of these emission guidelines.

b. Calculation of a Standard That Accounts for RULOF

Subpart Ba, both the presently applicable requirements and as the EPA has proposed to revise them, provides that, if a state has demonstrated that accounting for RULOF is appropriate for a particular affected EGU, the state may then apply a less stringent standard to that EGU. The EPA's proposed subpart Ba would require that, in doing so, the state must determine a source-specific BSER by identifying all the systems of emission reduction available for the source and evaluating each system using the same factors and evaluation metrics that the EPA considered in determining the BSER for the applicable subcategory.[479] As part of determining source-specific BSER, the state would also have to determine the degree of emission limitation that can be achieved by applying this source-specific BSER to the particular source. The state would then calculate and apply the standard of performance that reflects this degree of emission limitation.[480]

Consistent with these proposed requirements in subpart Ba, the EPA is proposing to require states invoking RULOF for affected coal-fired EGUs in the long-term subcategory to evaluate natural gas co-firing as a potential source-specific BSER. Additionally, if an EGU in the long-term subcategory can implement CCS but cannot achieve the degree of emission limitation prescribed by the presumptive standard of performance, the EPA is proposing that the state evaluate CCS with a source-specific degree of emission limitation as a potential BSER. The EPA is also proposing that states invoking RULOF for long-term and medium-term affected coal-fired EGUs must evaluate different levels of natural gas co-firing. For example, for a source in the medium-term subcategory that cannot reasonably co-fire 40 percent natural gas, the state must evaluate lower levels of natural gas co-firing unless it has demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. Similarly, if a state invoking RULOF for an affected EGU in the long-term subcategory demonstrates that the EGU cannot co-fire with natural gas at 40 percent, the EPA is proposing that the state must evaluate lower levels of co-firing as potential BSERs for the source, unless the state can demonstrate that

[479] To the extent that a state seeks to apply RULOF to a class of affected EGUs that the state can demonstrate are similarly situated in all meaningful ways, the EPA proposes to permit the state to conduct an aggregate analysis of the BSER factors for the entire class of EGUs for which RULOF has been invoked.
[480] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(f)).

it is physically impossible or technically infeasible for the source to co-fire natural gas. States may also consider additional potential source-specific BSERs for affected EGUs in either subcategory.

The EPA notes again that, under both the proposed subpart Ba and CAA section 111(d),[481] an affected EGU that cannot reasonably apply the EPA's BSER but can achieve the degree of emission limitation for the applicable subcategory through other reasonable systems of emission reduction cannot be given a less stringent standard of performance. In this case, the affected EGU's standard of performance would still reflect the degree of emission limitation achievable through application of the EPA's BSER.

The EPA has proposed in its revisions to subpart Ba that specific requirements would apply when invoking RULOF based on an affected source's remaining useful life.[482] Among other requirements, the EPA would have to either identify in an emission guideline the outermost date to cease operations for the relevant source category that qualifies for consideration of remaining useful life or provide a methodology and considerations for states to use in establishing such an outermost date. Proposed subpart Ba also provides that an affected source with a date to cease operations that is both imminent and prior to the outermost date could be eligible for a standard of performance that reflects that source's BAU. The EPA is proposing to supersede the application of subpart Ba with respect to the proposed requirements to establish outermost and imminent dates to cease operations for invoking RULOF based on an affected

[481] As discussed earlier in this preamble, permitting a state to apply a less stringent standard to an affected EGU that can achieve the degree of emission limitation the EPA determined is required would be inconsistent with CAA section 111(d). See also 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(g)).
[482] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(h), (i)).

EGU's remaining useful life. As explained earlier in this section of the preamble, the EPA has designed the subcategories for coal-fired affected EGUs under these emission guidelines to accommodate sources' operating horizons. This approach to subcategorization obviates the need to establish an outermost date to cease operations to bound states' and affected EGUs' consideration of remaining useful life. Additionally, the EPA is proposing to establish an imminent-term subcategory with a proposed BSER determination of routine operation and maintenance, which serves the same purpose as establishing an imminent date to cease operations under the RULOF provision. It is not anticipated that states will have a reason to invoke RULOF due to a coal-fired EGU's imminent date to cease operations based on the structure of the subcategories under these emission guidelines.

Because of the small number of sources in the oil- and natural gas-fired steam generating unit subcategories and the diversity of circumstances in which they operate, the EPA is not proposing to establish outermost or imminent dates to cease operations for the purpose of considering remaining useful life for these sources. Regardless, because the proposed BSER determinations for these EGUs is routine methods of operation and maintenance (other than for low-load oil- and natural gas-fired steam generating units), the EPA does not anticipate that states will find it necessary to invoke RULOF for these sources.

The proposed subpart Ba would require that any plan that applies a less stringent standard to a particular affected EGU based on remaining useful life must include the date by which the EGU commits to permanently cease operations as an enforceable requirement.[483] The plan would also have to include measures that provide for the implementation and enforcement of such a

[483] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(h), (i)(3)).

commitment. The EPA is not proposing to supersede this proposed requirement for the purpose of this emission guideline; states that include a RULOF standard based on an affected EGU's remaining useful life must make the date that the source commits to permanently cease operations enforceable in the state plan.

Similarly, subpart Ba would require that if a state seeks to rely on a source's operating conditions, such as its restricted capacity, as the basis for invoking RULOF and setting a less stringent standard, the state plan must include that operating condition as an enforceable requirement.[484] This requirement would apply to operating conditions that are within an affected EGU's control and is necessary to ensure that a source's standard of performance matches what that source can reasonably achieve and does not undermine the stringency of these emission guidelines.

The proposed presumptively approvable standards of performance for affected EGUs in these emission guidelines are expressed in the form of rate-based emission limitations, specifically, as lb CO_2/MWh. Therefore, to ensure transparency and to enable the EPA, states, and stakeholders to ensure that RULOF standards do not undermine the presumptive stringency of these emission guidelines, the EPA is proposing to require that standards of performance determined through this RULOF mechanism be in the same form of rate-based emission limitations.[485]

The EPA seeks comment on implementation of the proposed subpart Ba requirements pertaining to determining a source-specific BSER and calculating a less stringent standard for

[484] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(h)).
[485] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(f)(3)).

sources invoking RULOF under these emission guidelines. It also seeks comment on the proposed requirements that are specific to these emission guidelines, including but not limited to the proposed requirement that states evaluate certain control options for affected EGUs in the long-term and medium-term subcategories as part of their source-specific BSER determination and the proposal to not provide outermost or imminent dates to cease operations for the consideration of remaining useful life.

c. Consideration of Impacted Communities

While the consideration of RULOF may warrant application of a less stringent standard of performance to a particular affected EGU, such standards have the potential to result in disparate health and environmental impacts to communities most affected by and vulnerable to impacts from those EGUs. Those communities could be put in the position of bearing the brunt of the greater health and environmental impacts resulting from an affected EGU implementing a less stringent standard of performance than would otherwise have been required pursuant to the emission guidelines. A lack of consideration of such potential outcomes would be antithetical to the public health and welfare goals of CAA section 111(d).

Therefore, the proposed subpart Ba revisions would require that states applying less stringent standards of performance consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the affected EGU in determining source-specific BSERs and the degree of emission limitation achievable through application of such BSERs.[486] The state will have identified these communities as pertinent

[486] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(k)).

stakeholders in the process of meaningful engagement, which is discussed in section XI.F.1.b of this preamble.

The EPA is proposing that, pursuant to the proposed requirement to consider the potential pollution impacts and benefits for impacted communities, state plan submissions would have to demonstrate that the state considered where and how a less stringent standard of performance impacts these communities. The plan submission under these emission guidelines must clearly identify impacted communities and how the state determined which communities were considered. The EPA is proposing that, in evaluating potential source-specific BSERs, a state must describe the health and environmental impacts anticipated from each control option it considered. A state must document how it considered these impacts, including any health and environmental benefits of control options, in determining the source-specific BSER. The EPA is also proposing that states must consider and include in their state plan submissions any feedback they received during meaningful engagement regarding their proposed RULOF standards of performance.

As an example, the state plan submission could include a comparative analysis assessing potential BSER options for an affected EGU and the corresponding potential benefits to the identified communities under each option. If the comparative analysis shows that emissions from an affected EGU could be controlled at a higher cost than under the EPA's BSER but that such control benefits the communities that would otherwise be adversely impacted by a less stringent standard of performance, the state could balance these considerations and determine that a higher cost is warranted for the source-specific BSER.

The EPA solicits comments on the proposed requirements for implementing subpart Ba's proposed provisions for consideration of impacted communities under these emission guidelines.

In particular, the Agency is requesting comment on metrics or information concerning health and environmental impacts from affected EGUs that states can consider in source-specific RULOF determinations. As discussed in section XI.F.1.b, the EPA is also requesting comment on tools and methodologies for identifying communities that are most affected by and vulnerable to emissions from affected EGUs under these emission guidelines.

d. The EPA's Standard of Review of State Plans Invoking RULOF

Under CAA section 111(d)(2), the EPA has the obligation to determine whether a state plan submission is "satisfactory." This obligation extends to all aspects of a state plan, including the application of less stringent standards of performance that account for RULOF. Pursuant to CAA section 111(d) and the proposed subpart Ba provisions,[487] states carry the burden of making the demonstrations required under the RULOF mechanism and have the obligation to justify any accounting for RULOF in support of standards of performance that are less stringent than the proposed presumptively approvable standards in these emission guidelines. While the EPA has the discretion to supplement a state's demonstration, the EPA may also find that a state plan's demonstration is a basis for concluding that the plan is not "satisfactory" and may therefore disapprove the plan.

As a general matter, a less stringent standard of performance pursuant to RULOF must meet all other applicable requirements of subpart Ba and these emission guidelines.[488]

In determining whether a state has met its burden in providing a less stringent standard of performance based on RULOF, the EPA will consider, among other things, the applicability and

[487] See CAA section 111(d)(2), 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)).
[488] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(l)).

appropriateness of the information on which the state relied. Both a demonstration that a particular affected EGU meets the threshold requirements to invoke RULOF and the determination of a source-specific standard of performance entail the use of technical, cost, engineering, and other information. The proposed subpart Ba revisions would require states to use information that is applicable to and appropriate for the particular source at issue.[489] This means that, when available, the state must use source- and site-specific information. This is consistent with the premise that invoking RULOF is appropriate for a particular source when there are fundamental differences between the EPA's BSER and that source's specific circumstances.

In some instances, site-specific information may not be available. In such cases, it may be reasonable for a state to use information from, *e.g.*, cost, engineering, and other analyses the EPA has provided to support this rulemaking. The EPA is proposing that states using non-site-specific information must explain why that information is reasonable to rely on to determine a less stringent standard of performance based on RULOF. Regardless of the information used, it must come from reliable and adequately documented sources, which the proposed subpart Ba revisions explain presumptively include sources published by the EPA, permits, environmental consultants, control technology vendors, and inspection reports.[490]

The EPA solicits comment on the types of source-specific and other information that states should be required to provide to support the inclusion of standards of performance based

[489] See 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)(1)).
[490] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(j)(2)).

on RULOF in state plans, as well as on any additional sources of information that may be appropriate for states to use in this context.

e. Authority to Apply More Stringent Standards as Part of State Plans

As explained in the subpart Ba notice of proposed rulemaking, the EPA reevaluated its interpretation of CAA sections 111(d) and 116 and, consistent with its revised interpretation, has proposed revisions to subpart Ba to clarify that states may consider RULOF to include more stringent standards of performance in their state plans.[491] The allowance in CAA section 111(d)(1) that states may consider "other factors" does not limit states to considering only factors that may result in a less stringent standard of performance; other factors that states may wish to account for in applying a more stringent standard than provided in these emission guidelines include, but are not limited to, effects on local communities, the availability of control technologies that allow a particular source to achieve greater emission reductions, and local or state policies and requirements.

Pursuant to proposed subpart Ba, states seeking to apply a more stringent standard of performance based on other factors would have to adequately demonstrate that the standard is in fact more stringent than the presumptively approvable standard of performance for the applicable subcategory. However, a state would not be required to conduct a source-specific BSER evaluation for the purpose of applying a more stringent standard of performance, so long as the standard will achieve equivalent or better emission reductions. In this case, the EPA believes it is appropriate to defer to the state's discretion to impose a more stringent standard on an individual

[491] 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(m), (n)).

source because such a standard does not have the potential to undermine the presumptive stringency of these emission guidelines.

More stringent standards of performance must meet all applicable statutory and regulatory requirements, including that they are adequately demonstrated.[492] As for all standards of performance, the state plan must include requirements that provide for the implementation and enforcement of a more stringent standard. The EPA has the ability and authority to review more stringent standards of performance and to approve them provided that the minimum requirements of subpart Ba and these emission guidelines are met, rendering them federally enforceable.

The EPA requests comment on the implementation of the proposed subpart Ba provisions pertaining to more stringent standards of performance in the context of these particular emission guidelines.

[492] See 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(m)).

3. Increments of Progress and Milestones for Federally Enforceable Commitment to Cease Operations

The CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba provide that state plans must include legally enforceable increments of progress to achieve compliance for each designated facility when the compliance schedule extends more than a specified length of time from the state plan submission date.[493] The EPA's December 2022 proposed revisions to subpart Ba would require increments of progress when the compliance date is more than 16 months after the state plan submission deadline.[494] Under these proposed emission guidelines, the state plan submission date would be 24 months (see Section XI.F.2 of this preamble) from promulgation of the emission guidelines, which the EPA is currently anticipating will be June 2026. The proposed compliance date is January 1, 2030, which is more than 16 months after the state plan submission deadline. The EPA is therefore proposing to require that state plans include increments of progress as discussed in this section. For the purpose of these emission guidelines, the EPA refers to pre-January 1, 2030, enforceable requirements associated with the planning, construction, and operation of natural gas co-firing infrastructure and CCS as increments of progress. The EPA is also proposing separate, federally enforceable "milestones" associated with activities surrounding enforceable dates to permanently cease operations for EGUs in the imminent-term, near-term, and medium-term subcategories. These additional state plan requirements are intended to ensure that affected EGUs can complete the steps necessary to qualify for a subcategory with a less stringent BSER and to provide the public assurance that those steps will be concluded in a timely manner.

[493] 40 CFR 60.24a(d).
[494] See 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.24a(d)).

a. Increments of Progress

The EPA is proposing that state plans must include specified enforceable increments of progress as required elements for coal-fired EGUs that use co-firing to meet the standard of performance for the medium-term existing coal-fired steam generating subcategory or that use CCS to meet the standard of performance for the long-term existing coal-fired steam generating subcategory. This proposal adopts emission guideline-specific implementation of the five increments specified in the CAA section 111(d) implementing regulations at 40 CFR 60.21a(h). These five increments of progress are: (1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency; (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification; (3) Initiation of on-site construction or installation of emission control equipment or process change; (4) Completion of on-sites construction or installation of emission control equipment or process change; and (5) Final compliance.

Some increments have been adjusted to more closely align with planning, engineering, and construction steps anticipated for designated facilities that will be complying with standards of performance with co-firing or CCS, but they retain the basic structure and substance of the increments in the general implementing regulations. In addition, consistent with 40 CFR 60.24a(d), the EPA is proposing one additional increment of progress for both the long-term and medium-term coal-fired subcategories to ensure timely progress on the planning, permitting, and construction activities related to pipelines that may be required to enable full compliance with the applicable standard of performance. The EPA is also proposing a second additional increment of progress for the long-term subcategory related to the identification of an appropriate sequestration site.[495]

The EPA is proposing that final compliance with the applicable standard of performance, also defined as the final increment of progress in the implementing regulations, must occur no later than January 1, 2030. For the remaining increments, the EPA is not proposing date-specific deadlines for achieving increments of progress. Instead, we propose that states must assign calendar day deadlines for each of the remaining increments for each affected EGU in the medium-term and long-term coal-fired subcategories in their state plan submissions subject to one additional constraint: that the increment of progress corresponding to 40 CFR 60.21(h)(1) (submittal of a final control plan to the air pollution control agency) in both subcategories be assigned the earliest calendar date deadline among the increments. This approach would provide states with flexibility to tailor compliance timelines to individual facilities, allow simultaneous work toward separate increments, and still ensure full performance by 2030. The EPA solicits comment on this approach as well as whether the EPA should instead finalize date-specific deadlines or more general timeframes for achieving increments of progress rather than leaving the timing for most increments to state discretion. The EPA also seeks comment on the specific deadlines or timeframes that the EPA could assign to each increment under a more prescriptive approach.

[495] Affected EGUs do not necessarily have to implement the EPA's BSER technology to comply with their applicable standards of performance. States may choose to allow affected EGUs in the medium- and long-term coal-fired steam generating unit subcategories to meet their standards of performance using approaches other than natural gas co-firing and CCS, respectively. If they choose to do so, the EPA proposes that the state plan would be required to specify increments of progress for the relevant affected EGUs that are consistent with the increments in 40 CFR 60.21a(h), as well as dates for achieving each increment.

The EPA is not proposing increments of progress for either the imminent- or near-term subcategories for coal-fired steam generating units, or for oil- or natural gas-fired steam generating units. The proposed BSERs for these affected EGUs are routine operation and maintenance, which does not require the installation of new emission controls or operational changes. Because there is no need for the types of increments of progress specified in 40 CFR 60.21a(h) to ensure that affected EGUs in the imminent and near-term coal-fired and oil- and natural gas-fired subcategories can achieve full compliance by the compliance date, the EPA is proposing that the requirement for increments of progress in 40 CFR 60.24a(d) does not apply to these units.

For coal-fired EGUs falling within the medium-term subcategory, the EPA proposes the following increments of progress as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way. (2) Awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (4) Completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (5) Final compliance with the standard of performance by January 1, 2030.

In addition to the five increments of progress derived from the CAA section 111(d) implementing regulations, the EPA is proposing an additional increment of progress for affected EGUs that adopt co-firing to meet the standard of performance for the medium-term subcategory, to ensure timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities within subcategory. Affected EGUs are required to demonstrate that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting application process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permit applications is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.

For coal-fired EGUs falling within the long-term subcategory, the EPA proposes the following increments of progress as required, enforceable elements to be included in a state plan submission: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or FEED study. (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CCS on an annual basis. (4) Completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CCS on an annual basis. (5) Final compliance with the standard of performance by January 1, 2030.

In addition to the five increments of progress derived from the CAA section 111(d) implementing regulations, the EPA is proposing two additional increments for affected EGUs that adopt CCS to meet the standard of performance for the long-term subcategory. The first reflects the approach proposed earlier in this preamble for the co-firing subcategory to ensure timely completion of pipeline infrastructure and the second is designed to ensure timely selection of an appropriate sequestration site. As the first additional increment, the EPA proposes that affected EGUs using CCS to comply with their standards of performance be required to demonstrate that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.

The EPA proposes a second additional increment of progress for affected EGUs using CCS to comply with their standards of performance for the long-term subcategory, to ensure timely completion of site selection for geologic sequestration of captured CO_2 from the facility. Affected EGUs within this subcategory must submit a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

The EPA requests comment on the substance of each of the six proposed increments of progress for coal-fired steam generating units falling within the medium-term subcategory as well as the seven increments of progress proposed for the long-term subcategory. The EPA seeks comment on whether the increments contain an appropriate level of specificity to establish clear, verifiable criteria to ensure that states and affected EGUs are taking the steps necessary to reach full compliance. If commenters believe they do not, we request comment on the appropriate level of specificity for each increment. Additionally, as discussed in section XI.F.1.b.i of this preamble, the EPA is proposing a requirement that each state plan provide for the establishment of “CAA Section 111(d) EGU Rule Websites” by the owners or operators of affected EGUs. The EPA is further proposing that state plans must require affected EGUs with increments of progress to post those increments, the schedule required in the state plan for achieving them, and any documentation necessary to demonstrate that they have been achieved to this website in a timely manner.

b. Milestones for Federally Enforceable Commitment to Cease Operations

The EPA is proposing that state plans must include legally enforceable milestones for affected EGUs within the imminent-term, near-term, and medium-term coal-fired steam generating unit subcategories. As described in section X.C.3 of this preamble, the applicability criteria for each of the subcategories of coal-fired steam generating units include an affected

EGU's intended operating horizon, which is represented by a federally enforceable commitment to cease operation by a date certain. Accordingly, affected EGUs in the imminent-term, near-term, and medium-term subcategories have BSERs that are specifically tailored to and dependent on their shorter operating horizons. The EPA is aware that there are many processes an affected EGU must complete in order to permanently cease operation. Therefore, to ensure that affected EGUs can complete the steps necessary to qualify for a subcategory with a less stringent standard of performance and to provide the public assurance that those steps will be concluded in a timely manner, the EPA is proposing additional state plan requirements, referred to as "milestones," for EGUs in the imminent-term, near-term, and medium-term subcategories.

The proposed milestone reporting requirements count backward from an affected EGU's federally enforceable date to permanently cease operations to ensure timely progress toward that date. Five years before any date used to determine the applicable subcategory under these emission guidelines or 60 days after state plan submission, whichever is later, designated facilities must submit a Milestone Report to the applicable state administering authority that includes the following: (1) A summary of the process steps required for the affected EGU to cease operation by the federally enforceable date, including the approximate timing and duration of each step. (2) A list of key milestones, metrics that will be used to assess whether each milestone has been met, and calendar day deadlines for each milestone. These milestones must include at least the following: notice to the official reliability authority of the federally enforceable retirement date; submittal of an official suspension filing (or equivalent filing) made to the affected EGU's reliability authority; and submittal of an official retirement filing with the unit's reliability authority. (3) An analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar units within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines. (4) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority, as well as any filings with the SEC or notices to investors in which the plans for the EGU are mentioned and any integrated resource plan.

For each of the remaining years prior to the federally enforceable date to permanently cease operations that is used to determine the applicable subcategory, affected EGUs must submit an annual Milestone Status Report that addresses the following: (1) progress toward meeting all milestones and related metrics identified in the Milestone Report; and (2) supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

The EPA is also proposing that affected EGUs with reporting milestones associated with federally enforceable commitments to permanently cease operations would be required to submit a Final Milestone Status Report no later than 6 months following its federally enforceable date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans. The EPA requests input on whether 6 months after the federally enforceable date is an appropriate period of time to capture any actions affected EGUs taken following cessation of operations.

The EPA is proposing that affected EGUs with reporting milestones for federally enforceable commitments to permanently cease operations would be required to post their initial

Milestone Report, annual Milestone Status Reports, and final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the CAA Section 111(d) EGU Rule Website, as described in Section XI.F.1.b, within 30 business days of being filed.

The EPA recognizes that applicable regulatory authorities, retirement processes, and retirement approval criteria will vary across states and affected EGUs. The proposed milestone requirements are intended to establish a general framework flexible enough to account for significant differences across jurisdictions while assuring timely planning toward the dates by which affected EGUs permanently cease operations. The EPA requests comment on this proposed approach, specifically whether any jurisdictions present unique state circumstances that should be considered when defining milestones and the required reporting elements.

4. Testing and Monitoring Requirements

The EPA is proposing to require states to include in their plans a requirement that affected EGUs monitor and report hourly CO_2 mass emissions emitted to the atmosphere, total heat input, and total gross electricity output, including electricity generation and, where applicable, useful thermal output converted to gross MWh, in accordance with the 40 CFR part 75 monitoring and reporting requirements. Under this proposal, affected EGUs would be required to use a 40 CFR part 75 certified monitoring methodology and report the hourly data on a quarterly basis, with each quarterly report due to the Administrator 30 days after the last day in the calendar quarter. The monitoring requirements of 40 CFR part 75 require most fossil fuel-fired boilers to use a CO_2 CEMS, including a CO_2 concentration monitor and stack gas flow monitor, although some oil- and natural gas-fired boilers may have options to use alternative measurement methodologies (*e.g.*, fuel flow meters). A CO_2 CEMS is the most technically reliable method of emission measurement for EGUs, as it provides a measurement method that is performance based rather than equipment specific and is verified based on NIST traceable standards. A CEMS provides a continuous measurement stream that can account for variability in the fuels and the combustion process. Reference methods have been developed to ensure that all CEMS meet the same performance criteria, which helps to ensure consistent, accurate data.

The majority of EGUs will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit emissions reports under 40 CFR part 75 as they have under existing programs, such as the Acid Rain Program (ARP) and RGGI—a cooperative of several states formed to reduce CO_2 emissions from EGUs. The majority of coal- and oil-fired EGUs not subject to the ARP or RGGI are subject to the MATS program and, therefore, will have installed stack gas flow monitors and/or CO_2 concentration monitors necessary to comply with the MATS. Relying on the same monitors that are certified and quality-assured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs.

The EPA requests comment on monitoring and reporting requirements for captured CO_2 mass emissions and net electricity output, and on allowable testing methods for stack gas flow rate.

The CCS process is also subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The "suppliers of carbon dioxide" source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the "geologic sequestration of carbon dioxide" source category of the GHGRP (GHGRP subpart RR). In 2022, to complement GHGRP subpart RR, the EPA proposed the "geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916" source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[496,497,498]

The EPA is proposing that any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the captured CO_2 is sent offsite, then the facility injecting the CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. This proposal does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic

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[496] 87 FR 36920 (June 21, 2022).
[497] International Standards Organization (ISO) standard designated as CSA Group (CSA) / American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as "CSA/ANSI ISO 27916:2019").
[498] As described in 87 FR 36920 (June 21, 2022), both subpart RR and proposed subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

sequestration site are not part of that calculation. However, to verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, we are leveraging regulatory requirements under the GHGRP. Further, we note that the determination that the BSER is adequately demonstrated relies on geologic sequestration that is not associated with EOR; however EGUs would have the option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. We also emphasize that this proposal does not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU assure that captured CO_2 is managed at an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the proposed rule.

The EPA requests comment on the following questions related to additional monitoring and reporting of hourly captured CO_2 under 40 CFR part 75: a) should EGUs with carbon capture technologies be required to monitor and report the hourly captured CO_2 mass emissions under 40 CFR part 75, b) if EGUs with carbon capture technologies are not required to monitor and report the hourly captured CO_2 mass emissions, the calculation procedures for total heat input and NO_X rate in appendix F to 40 CFR part 75 may no longer provide accurate results; therefore, what changes might be necessary to accurately determine total heat input and NO_X rate, c) to ensure accurate and complete accounting of CO_2 mass emissions emitted to the atmosphere and captured for use or sequestration, at what locations should CO_2 concentration and stack gas flow be monitored, and should other values also be monitored at those locations, d) are there quality assurance activities outside of those required under 40 CFR part 75 for CO_2

concentration monitors and stack gas flow monitors that should be required of the monitors to accurately and reliably measure captured CO_2 mass emissions, and e) what monitoring plan, quality assurance, and emissions data should be reported to the EPA to support evaluation and ensure consistent and accurate data as it relates to CO_2 emissions capture.

The 40 CFR part 75 monitoring and reporting provisions require hourly reporting of total gross electricity output, including useful thermal output, but do not require the reporting of net electricity output. The EPA requests comment on the following questions related to reporting of net electricity output: a) should EGUs be required to measure and report total net electricity output, including useful thermal output, under 40 CFR part 75, b) what guidance should the EPA provide on how to measure and apportion net electricity output, c) should EGUs measure and report net electricity output at the unit or facility level, and d) what monitoring plan, quality assurance, and output data should be reported to the EPA to support evaluation and ensure consistent and accurate data as it relates to total net electricity output.

To calculate CO_2 mass emissions at a fossil fuel-fired boiler, the EGU typically measures CO_2 concentration and flue gas flow rate as the exhaust gases from combustion pass through the stack (or duct). Under 40 CFR part 75, EGUs must complete regular performance tests on the flue gas flow monitor based on EPA Reference Method 2 or its allowable alternatives that are provided in 40 CFR part 60, appendices A-1 and A-2. In general, the allowable alternative measurement methods reduce or eliminate the potential overestimation of stack gas flow rate that results from the use of EPA Reference Method 2 when the specific flow conditions (*e.g.*, angular flow) are present in the stack. However, EGUs with stack gas flow monitors are not required to use the allowable alternative measurement methods and EGUs may change methods at any time. The EPA requests comment on the following questions related to the use of EPA Reference

Method 2 and its allowable alternatives for stack gas flow monitors under 40 CFR part 75: a) should or under what conditions should EGUs be required to conduct a flow study and choose the appropriate EPA reference method for each stack gas flow monitor based on the results of the study, b) once an EGU selects the use of an EPA reference method for a stack gas flow monitor, regardless of the basis for that selection, should the EGU be required to continue using the same EPA reference method until a flow study or other engineering justification is made to change the EPA reference method, and c) what additional monitoring plan, quality assurance, and emissions data should be reported to the EPA to support evaluation and ensure consistent and accurate data as it relates stack gas flow rate and performance of the stack gas flow monitor.

E. Compliance Flexibilities

In developing these proposed emission guidelines, the EPA has heard from stakeholders seeking compliance flexibility in light of the rapidly evolving and dynamic nature of the power sector. In particular, stakeholders have requested that the EPA allow states to include flexibilities such as averaging and market-based trading in their state plans, as has been permitted under prior EPA rules. This section discusses considerations related to potential compliance flexibilities in the context of this particular rule and set of regulated sources, and solicits comment on the appropriateness of averaging and trading for these emission guidelines.

1. Overview

In the proposed subpart Ba revisions, “Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)” (87 FR 79176; December 23, 2022), the EPA explained that under its proposed interpretation of CAA section 111, each state is permitted to adopt measures that allow its sources to meet their emission limits in the aggregate when the EPA determines, in any particular emission guideline, that it is appropriate to do so given, inter alia, the pollutant, sources, and standards of performance at issue. Thus, the EPA has proposed to return to its longstanding position that CAA section 111(d) authorizes the EPA to approve state plans that achieve the requisite emission limitation through aggregate reductions from their sources, including through trading or averaging, where appropriate for a particular emission guideline and consistent with the intended environmental outcomes of the guideline.[499] See 87 FR 79208 (December 23, 2022).

Consistent with the return to this longstanding position, the EPA is taking comment on whether trading and averaging are appropriate under these emission guidelines. If permitted, states would not be required to allow for such compliance mechanisms in their state plans but could provide for trading and averaging at their discretion.[500] This section discusses considerations related to the appropriateness of trading and averaging in the context of these emission guidelines and solicits comment on these considerations. This section also takes comment on how trading and averaging programs, if permitted, could be designed to ensure that

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[499] The EPA has authorized trading or averaging as compliance methods in several emission guidelines. See, *e.g.*, 40 CFR 60.33b(d)(2) (emission guidelines for municipal waste combustors permit state plans to establish trading programs for NO_X emissions); 70 FR 28606, 28617 (May 18, 2005) (Clean Air Mercury Rule authorized trading) (vacated on other grounds); 40 CFR 60.24(b)(1) (subpart B CAA section 111 implementing regulations promulgated in 2005 allow states' emission standards to be based on an "allowance system"); 80 FR 64662, 64840 (October 23, 2015) (CPP authorizing trading or averaging as a compliance strategy). In the recent supplemental proposal to promulgate emission guidelines for the oil and natural gas industry, the EPA has also proposed to allow states to permit sources to demonstrate compliance in the aggregate. 87 FR 74702, 74812 (December 6, 2022).

[500] The EPA notes that these flexibilities, trading and averaging, would be used to comply with standards of performance, rather than to establish standards of performance in the first instance. In contrast to the RULOF mechanism, which, as described in section XI.D.2 of this preamble, states may use to establish different standards of performance than those described by the EPA's BSER, trading or averaging may be used to demonstrate compliance with already established standards of performance. That is, states incorporating trading or averaging would not need to undergo a RULOF demonstration for sources participating in trading or averaging programs.

state plans maintain the level of emission performance by affected EGUs that is required under these proposed emission guidelines, and it includes illustrative program design methods.

As discussed in section XI.C of this preamble, state plans must demonstrate that they achieve a level of emission performance by affected EGUs that is consistent with the application of the BSER. If a state plan was to include trading or averaging, it would need to provide a demonstration that affected EGUs complying through such flexible mechanisms would still achieve an equivalent level of emission performance consistent with the application of the BSER. In the case of averaging, discussed in section XI.E.3 of this preamble, an equivalence demonstration would be relatively straightforward. For emission trading programs, ensuring equivalent emission performance in the aggregate may be more difficult, especially given the current rapid evolution of the affected source category for these emission guidelines. In section XI.E.2 of this preamble, the EPA discusses program design examples as well as potential design elements and takes comment on whether they could ensure that use of emission trading does not erode the emission performance improvements that these emission guidelines are designed to achieve.

The EPA also notes that, if trading and averaging are permitted under these emission guidelines, states that incorporate trading or averaging into their state plans would need to conduct meaningful engagement on this aspect of their plans with pertinent stakeholders, just as they would need to do for any other part of a plan. As discussed in greater detail in section XI.F.1.b of this preamble, meaningful engagement provides an opportunity for communities most affected by and vulnerable to the health and environmental impacts of a plan to provide input, including input on any impacts resulting from trading or averaging.

2. Emission Trading

The EPA is seeking comment on whether it is appropriate to allow state plans to include emission trading programs as a compliance flexibility for affected EGUs under these emission guidelines, including whether certain types of trading programs may be more appropriate than others. This section discusses considerations related to whether the EPA should permit emission trading, as well as how, if emission trading is allowed, states could potentially incorporate a rate-based trading program or a mass-based trading program in a way that preserves the stringency of these emission guidelines. The EPA is seeking comment on these potential methods, as well as on other methods that could maintain the required level of emission performance under the proposed emission guidelines.

a. Considerations for Emission Trading in State Plans

Emission trading has been used to achieve required emission reductions in the power sector for nearly 3 decades. In Title IV of the Clean Air Act Amendments of 1990, Congress specified the design elements for the Acid Rain Program, a 48-state allowance trading program to reduce SO_2 emissions and the resulting acid precipitation. Building on the success of that first allowance trading program as a tool for addressing multi-state air pollution issues, the EPA has promulgated and implemented multiple allowance trading programs since 1998 for SO_2 or NO_X emissions to address the requirements of the CAA's good neighbor provision with respect to successively more stringent NAAQS for fine particulate matter and ozone. The EPA currently administers eight power sector emission trading programs that differ in pollutants, geographic regions, covered time periods, and levels of stringency.[501] Annual progress reports demonstrate that EPA trading programs have been successful in mitigating the problems they were designed to address, exhibiting significant emission reductions and extraordinarily high levels of compliance.[502] In addition, several states have implemented intrastate or regional CO_2 emissions trading programs to address GHG emissions from the power sector (the RGGI and California trading programs, respectively).

In general, emission trading programs provide flexibility for EGUs to secure emission reductions at a lower cost relative to more prescriptive forms of regulation. Emission trading can allow the owners and operators of EGUs to prioritize emission reduction actions where they are the quickest or cheapest to achieve while still meeting electricity demand and broader environmental and economic performance goals. These benefits are heightened where there is a diverse set of emission sources (*e.g.*, variation in technology, fuel type, age, and operating parameters) included in an emission trading program. This diversity of sources is typically accompanied by differences in marginal emission abatement costs and operating parameters, resulting in heterogeneity in economic emission reduction opportunities that can be optimized through the compliance flexibility provided through emission trading. In addition, the EPA has observed, with the support of multiple independent analyses, that there is significant evidence

[501] The six current CSAPR trading programs are the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR SO_2 Group 1 Trading Program, CSAPR SO_2 Group 2 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR NO_X Ozone Season Group 3 Trading Program. The regulations for the six CSAPR programs are set forth at subparts AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97. The regulations for the Texas SO_2 Trading Program are set forth at subpart FFFFF of 40 CFR part 97. The Acid Rain Program SO_2 trading program is set forth in Title IV of the Clean Air Act Amendments of 1990.
[502] Environmental Protection Agency (2021). Power Sector Programs—Progress Report. EPA. *https://www3.epa.gov/airmarkets/progress/reports/index.html*.

that implementation of trading programs prompted greater innovation and deployment of clean technologies that reduce emissions and control costs.[503]

Emission trading may provide important benefits as the fleet of EGUs affected by these emission guidelines is rapidly evolving. Having flexibility to prioritize the most cost effective emission reductions among affected EGUs may reduce the cost of compliance as well as provide flexibility for fleet management, while achieving the requisite level of emission performance. In particular, emission trading may provide short-term operational flexibility to meet reliability needs.

At the same time, a rapidly evolving fleet of affected EGUs may pose challenges for implementing an emission trading program, especially in the context of the emission guidelines that the EPA is proposing here. The EPA notes that the proposed emission guidelines only include steam generating units and that the fleet of affected EGUs is expected to shrink significantly under BAU projections (see section IV.F of this preamble). As a result, there is unlikely to be as much diversity in cost and emission performance among affected emission sources (resulting in less diversity in emission reduction opportunities and marginal abatement costs) as seen in prior emission trading programs for the electric power sector. The projected BAU contraction of the fleet over the next 10 to 15 years also means there may be few affected emission sources in a state that could be included in an emission trading program.

The utility of trading under these emission guidelines may also be obviated by subcategories the EPA has proposed to establish. The specific subcategories proposed under

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[503] LaCount, M. D., Haeuber, R. A., Macy, T. R., & Murray, B. A. (2021). Reducing Power Sector Emissions under the 1990 Clean Air Act Amendments: A Retrospective on 30 Years of Program Development and Implementation. Atmospheric environment (Oxford, England: 1994), 245, 1–10. *https://doi.org/10.1016/j.atmosenv.2020.118012*.

these emission guidelines are designed to provide for much of the same operational flexibility as trading; as a result, the EPA believes that it would not be appropriate to allow affected EGUs in certain subcategories to comply with their standards of performance through trading. As discussed in section X.D.3 of this preamble, the BSER determinations for the imminent- and near-term coal-fired steam generating unit subcategories are designed to take into account factors such as operating horizon and load level (expressed as annual capacity factor). In addition, states may invoke RULOF, where appropriate, when establishing standards of performance for certain affected EGUs. An emission trading program that includes affected EGUs that have BSERs and resulting standards of performance based on limited expected emission reduction potential--affected EGUs in the imminent- and near-term coal-fired subcategories, as well as natural gas- and oil-fired steam generating units--or a less stringent standard of performance established through a state invoking RULOF, may introduce the risk of undermining the intended stringency of the emission guidelines for other facilities that would not otherwise meet the RULOF criteria. In addition, affected EGUs in the long-term subcategory that receive the IRC section 45Q tax credit for permanent sequestration of CO_2 may have an overriding incentive to maximize both the application of the CCS technology and total electric generation, leading to source behavior that may be non-responsive to the economic incentives of a trading program.

The EPA requests comment on these challenges and on whether, in light of these and other considerations, emission trading should be permitted as a compliance flexibility under these emission guidelines. In particular, the EPA is soliciting comment on whether there is utility in permitting trading for any of the proposed subcategories of affected EGUs, after considering the operational flexibility already provided by the structure of those subcategories and their proposed BSERs. The EPA is also soliciting comment on whether trading could or should be permitted for certain subcategories and not others, and why. In the following sections, the EPA discusses potential rate-based and mass-based emission trading program approaches that, if trading is permitted, could potentially be included in a state plan and solicits comment on applied implementation issues in the context of these proposed emission guidelines and the considerations discussed earlier in this preamble.

b. Rate-based Emission Trading

A rate-based trading program allows affected EGUs to trade compliance instruments that are generated based on their emission performance. This section describes one method of how states could establish a rate-based trading program as part of a state plan. The EPA requests comment on whether this or another method of rate-based trading could ensure the level of emission performance required under these emission guidelines.

In this example, affected EGUs that perform at a lower emission rate (lb CO_2/MWh) than their standard of performance would be issued compliance instruments that are denominated in one ton of CO_2. A tradable instrument denominated in another unit of measure, such as a MWh, is not fungible in the context of a rate-based emission trading program. A compliance instrument denominated in MWh that is awarded to one affected EGU may not represent an equivalent amount of emissions credit when used by another affected EGU to demonstrate compliance, as the CO_2 emission rates (lb CO_2/MWh) of the two affected EGUs are likely to differ. This may pose challenges for states trying to demonstrate equivalence with the intended stringency of the BSER.

These compliance instruments could be transferred among affected EGUs, making them "tradable." Compliance would be demonstrated for an affected EGU based on a combination of its reported CO_2 emission performance (in lb CO_2/MWh) and, if necessary, the surrender of an appropriate number of tradable compliance instruments, such that the demonstrated lb CO_2/MWh emission performance is equivalent to the rate-based standard of performance for the affected EGU.

Specifically, each affected EGU would have a particular standard of performance, based on the degree of emission limitation achievable through application of the BSER, with which it would have to demonstrate compliance. Under a rate-based trading program, affected EGUs performing at a CO_2 emission rate below their standard of performance would be awarded compliance instruments at the end of each control period denominated in tons of CO_2. The number of compliance instruments awarded would be equal to the difference between their standard of performance CO_2 emission rate and their actual reported CO_2 emission rate multiplied by their generation in MWh. Affected EGUs performing worse than their standard of performance would be required to obtain and surrender an appropriate number of compliance instruments when demonstrating compliance, such that their demonstrated CO_2 emission rate is equivalent to their rate-based standard of performance. Transfer and use of these compliance instruments would be accounted for with a rate adjustment as each affected EGU performs its compliance demonstration.

In general, rate-based emission trading can by design assure achievement of the requisite level of emission performance for affected sources, because reduced utilization and retirements are automatically accounted for in the award of the compliance instrument. By default, only operating steam generating units could receive or participate in the trading of compliance instruments.

The EPA is seeking comment on whether rate-based emission trading might be appropriate under these emission guidelines. In particular, the EPA requests comment on whether there is utility in permitting rate-based emission trading and whether such program could be designed to preserve the intended stringency of these emission guidelines given the structure of the proposed subcategories, their proposed BSERs, and the dynamic nature of the power sector. The EPA also requests comment on any other methods of rate-based trading that would preserve the intended stringency of these emission guidelines.

c. Mass-based Emission Trading

A mass-based trading program establishes a budget of allowable mass emissions for a group of affected EGUs, with tradable instruments (typically referred to as “allowances”) issued to affected EGUs in the amount equivalent to the emission budget. Each allowance would represent a tradable permit to emit one ton of CO_2, with affected EGUs required to surrender allowances in a number equal to their reported CO_2 emissions during each compliance period. This section describes one method of how states could establish a mass-based trading program as part of a state plan. The EPA requests comment on whether this or another method of mass-based trading could ensure the level of emission performance required under these emission guidelines.

As previously discussed, mass-based emission trading has been used in the power sector at the Federal, regional, and state levels for nearly 3 decades. Owners and operators of EGUs, utilities, and state agencies thus have extensive familiarity with mass-based emission trading, which could make the design and implementation of a mass-based trading program as part of a state plan relatively straightforward. However, this familiarity comes with an awareness on the part of states and the EPA of the need to tailor the design of a mass-based emission trading program to the situation in which it is applied. This is especially important in instances where a sector is rapidly evolving. Past experience shows that emission budgets have often been overestimated when set many years in advance of the start of a program, as economic and technological conditions have changed significantly between the time the program was adopted and when compliance obligations begin. Projecting affected EGU fleet composition and utilization beyond the relative near term has become increasingly challenging in light of the aforementioned rapid evolution of the electric power sector, driven by factors including changes in relative fuel prices and continued rapid improvement in the cost and performance of wind and solar generation, along with new incentives for technology deployment provided by the IIJA and the IRA. Without a regular adjustment to the mass budget, if enough affected EGUs cease operations or reduce utilization, the source category could reach a point at which none of the remaining affected EGUs have to do anything to improve their emission performance. In this case, the mass budget would be established at a level such that the sources would not be collectively meeting a level of emission performance commensurate with each source's achieving its rate-based standard of performance. This outcome would be contrary to the statutory purpose of mitigating emissions from the source category to an extent that reflects application of the BSER. Such an outcome would be likewise contrary to EPA's long-standing requirement, reflected in its implementing regulations for section 111(d), that state plans establish standards of performance that are at least as stringent as EPA's emission guidelines.

States would thus need to ensure that affected EGUs participating in a mass-based trading program continue to meet the level of emission performance prescribed by category-wide, source-specific implementation of the rate-based standards of performance. This could be done by regularly adjusting emission budgets to account for sources that cease operations or change their utilization. One budget adjustment method that the EPA has developed is dynamic budgeting, as applied in the Good Neighbor Plan, in which budgets are updated annually based on recent historical generation. States could apply a similar dynamic budgeting process to mass-based trading implemented under these emission guidelines. In this context, states could establish an emission budget based on the unit-specific standards of performance of the participating affected EGUs, as described in section XI.D of this preamble, multiplied by each affected EGU's recent historical generation. The emission budgets would be updated periodically to account for units that reduce utilization or cease operation. This is one way that states could assure achievement of the requisite level of emission performance for affected EGUs through mass-based trading, though the EPA acknowledges that state or regional mass-based trading programs may have developed other regular budget adjustment methods that could provide similar assurance.

The EPA is seeking comment on whether mass-based emission trading might be appropriate under these emission guidelines. In particular, the EPA requests comment on whether there is utility in permitting mass-based emission trading and whether such program could be designed to preserve the intended stringency of these emission guidelines given the structure of the proposed subcategories, their proposed BSERs, and the dynamic nature of the power generation sector. The EPA is also seeking comment on whether the method of mass-based emission trading using dynamic budgeting, as discussed in this section, might be appropriate under these emission guidelines. The EPA is also seeking comment on other approaches or features that could ensure that emission budgets reflect the stringency that would be achieved through unit-specific application of rate-based standards of performance.

d. General Emission Trading Program Implementation Elements

The EPA notes that state plans would need to establish procedures and systems necessary to implement and enforce an emission trading program, whether it is rate-based or mass-based.

This would include, but is not limited to, establishing compliance timeframes and the mechanics for demonstrating compliance under the program (*e.g.*, surrender of compliance instruments as necessary based on monitoring and reporting of CO_2 emissions and generation); establishing requirements for continuous monitoring and reporting of CO_2 emissions and generation; and developing a tracking system for tradable compliance instruments. Additionally, for states implementing a mass-based emission trading program, state plans would need to specify how allowances would be distributed to participating affected EGUs.

The EPA is requesting comment on whether and to what extent there would be a desire, if emission trading is permitted under these emission guidelines, to capitalize on the EPA's existing reporting and compliance tracking infrastructure to support state implementation of an emission trading program included in a state plan.

e. Banking of Compliance Instruments

The EPA requests comment on whether, if emission trading is permitted under these emission guidelines, state plans should be allowed to provide for banking of tradable compliance instruments (hereafter referred to as "allowance banking," although it is relevant for both mass-based and rate-based trading programs). Allowance banking has potential implications for a trading program's ability to maintain the requisite environmental performance of the standards of performance. The EPA recognizes that allowance banking (that is, permitting allowances that remain unused in one control period to be carried over for use in future control periods) may provide incentives for early emission reductions, promote operational flexibility and planning, and facilitate market liquidity. However, the EPA has observed that unrestricted allowance banking from one control period to the next (absent provisions that adjust future control period budgets to account for banked allowances) may result in a long-term allowance surplus that has the potential to undermine a trading program's ability to ensure that, at any point in time, the affected sources are achieving the required level of emission performance. In addition to requesting comment on whether the EPA should allow allowance banking if emission trading is permitted under these emission guidelines, the EPA requests comment on the treatment of banked allowances, specifically whether all or only some portion of an allowance bank could be carried over for use in future control periods or if additional program design elements would be necessary to accommodate allowance banking.

f. Interstate Emission Trading

The EPA is requesting comment on whether, if emission trading is permitted under these emission guidelines, it should allow for interstate emission trading. Given the interconnectedness of the power sector and given that many utilities operate in multiple states, interstate emission trading may increase compliance flexibility. For interstate emission trading programs to function successfully, all participating states would need to, at a minimum, use the same form of trading and have identical program requirements. If interstate emission trading were allowed, there are many other requirements for program reciprocity and approvability that would need to be established in the emission guidelines, in addition to providing mechanisms for submission and EPA review of state plans that include interstate trading mechanisms. Given the increased level of program complexity that would be necessary to accommodate interstate trading, the operational flexibilities already provided by the structure of the proposed subcategories and their proposed BSERs, and the dynamic nature of the power sector, the EPA requests comment on whether there is utility in providing for it under these emission guidelines. In the event it is permitted, the EPA is requesting comment on the information, guidance, and requirements the

EPA would need to provide for states to implement successful interstate emission trading programs.

3. Rate-based Averaging

The EPA is seeking comment on whether it is appropriate to allow state plans to include rate-based averaging as a compliance flexibility for affected EGUs under these emission guidelines. This section discusses considerations related to this question as well as how, if permitted under these emission guidelines, states could potentially incorporate a rate-based averaging program in a way that preserves the stringency of these emission guidelines. The EPA is seeking comment on one potential method, as well as other methods that could maintain the required level of emission performance under the proposed emission guidelines.

Averaging allows multiple affected EGUs to jointly meet a rate-based emission standard. Affected EGUs participating in averaging could, for example, demonstrate compliance through an effective CO_2 emission rate that is based on a gross generation-based weighted average of the required standards of performance of the affected EGUs that participate in averaging. The scope of such averaging could apply at the facility level or the owner or operator level. This method for calculating a composite rate could demonstrate equivalence with the intended emission performance under these emission guidelines.

Averaging can provide potential benefits. First, it offers some flexibility for sources to target cost effective reductions at any affected EGUs. For example, owners or operators of affected EGUs might target installation of emission control approaches at units that operate more. Second, averaging at the facility level provides greater ease of compliance accounting for affected EGUs with a complex stack configuration (such as a common- or multi-stack configuration). In such instances, unit-level compliance involves apportioning reported emissions to individual affected EGUs that share a stack based on electricity generation or other parameters.

However, the EPA notes that the subcategory approach in these emission guidelines already provides significant operational flexibility for affected EGUs, potentially making the provision of further flexibility through averaging redundant or inappropriate, especially at the owner or operator level.

The EPA is seeking comment on whether rate-based averaging should be permitted as a compliance flexibility, as well as on the illustrative method for developing a composite standard of performance for the purposes of rate-based averaging. The EPA is also seeking comment on any other considerations related to rate-based averaging, including whether the scope of averaging should be limited to a certain level of aggregation (*e.g.*, to facility-level rate-based averaging).

4. Relationship to Existing State Programs

The EPA recognizes that many states have adopted binding policies and programs under their own authorities (with both a supply-side and demand-side focus) that have significantly reduced CO_2 emissions from EGUs, that these policies will continue to achieve future emission reductions, and that states may continue to adopt new power sector policies addressing GHG emissions. States have exercised their power sector authorities for a variety of purposes, including economic development, energy supply and resilience goals, conventional and GHG pollution reduction, and generating allowance proceeds for investments in communities disproportionately impacted by environmental harms. The scope and approach of EPA's proposed emission guidelines differs significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, and this proposal operates more narrowly to improve the CO_2 emission performance of a subset of EGUs within the broader electric power sector. The Agency recognizes the importance of state programs and their potential to reduce power sector CO_2 emissions through a range of strategies broader than those proposed here pursuant to CAA section 111(d). To help facilitate the continued operation of existing state programs and to preserve opportunities for states to set and pursue their own power sector CO_2 emission reduction goals, the EPA seeks comment on whether there are any elements of the proposed emission guidelines that might interfere with the implementation of state policies and programs that are designed to reduce power sector CO_2 emissions, including those that apply CO_2 emission limitations to fossil fuel-fired EGUs that may be subject to the proposed emission guidelines.

F. State Plan Components and Submission

This section describes the proposed requirements for the contents of state plans, the proposed timing of state plan submissions, and the EPA's review of and action on state plan submissions. This section also discusses issues related to the applicability of a Federal plan and timing for the promulgation of a Federal plan.

As explained earlier in this preamble, the requirements of 40 CFR part 60, subpart Ba, govern state plan submissions under these emission guidelines. Where the EPA is proposing to add to, supersede, or otherwise vary the requirements of subpart Ba for the purposes of state plan submissions under these particular emission guidelines,[504] those proposals are addressed explicitly in section XI.F.1.b on specific state plan requirements and throughout this preamble. Unless expressly amended or superseded in these proposed emission guidelines, the provisions of subpart Ba would apply.

[504] See 40 CFR 60.20a(a)(1).

1. Components of a State Plan Submission

The EPA is proposing that a state plan must include a number of discrete components. These proposed plan components include those that apply for all state plans pursuant to 40 CFR part 60, subpart Ba. In addition, the EPA is proposing that other plan components would apply under these emission guidelines based on the type of plan submitted. For example, these required plan components may relate to the specific types of standards of performance for affected EGUs that are adopted by a state and incorporated into their state plan.

a. General Components

The CAA section 111 implementing regulations provide separate lists of administrative and technical criteria that must be met in order for a state plan submission to be deemed complete. The EPA's proposed revisions to subpart Ba would add one item to the list of administrative criteria related to meaningful engagement.[505] If finalized, the applicable administrative completeness criteria for state plan submissions are: (1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof; (2) Evidence that the state has adopted the plan in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter "document") in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date; (3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan; (4) A copy of the official state regulation(s) or document(s) submitted for approval and incorporated by reference into the plan, signed, stamped, and dated by the appropriate state official indicating that they are

[505] See 87 FR 79176, 79204 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.27a(g)(2)).

fully adopted and enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submission must indicate the changes made to the approved plan by redline/strikethrough; (5) Evidence that the state followed all applicable procedural requirements of the state's regulations, laws, and constitution in conducting and completing the adoption/issuance of the plan; (6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice; (7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23; (8) Compilation of public comments and the state's response thereto; and (9) Evidence of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, and a summary of stakeholder input received.

The technical criteria required for all plans must include each of the following:[506] (1) Description of the plan approach and geographic scope; (2) Identification of each designated facility (*i.e.*, affected EGU); identification of standards of performance for each affected EGU; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3) Identification of compliance schedules and/or increments of progress; (4) Demonstration that the state plan submission is projected to achieve emission performance under the applicable emission guidelines; (5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6)

[506] 40 CFR 60.27a(g)(3)).

Demonstration that each emission standard is quantifiable, permanent, verifiable, and enforceable.

b. Specific State Plan Requirements

Consistent with the requirements in subpart Ba, the EPA is proposing in the regulatory text that applies for these emission guidelines specific requirements that demonstrate that standards of performance for affected EGUs included in a state plan are quantifiable, verifiable, permanent, and enforceable. Consistent with CAA section 302(k), emission standards or limitations must be continuous in nature. This includes requirements that apply for all affected EGUs subject to a standard of performance under a state plan pursuant to these proposed emission guidelines, as well as requirements that apply for affected EGUs within a specific subcategory. These proposed requirements include:

- Identification of affected EGUs;
- Identification of standards of performance for each affected EGU in lb CO_2/MWh-gross basis over an extended period of time (*e.g.*, an annual calendar year), including provisions for implementation and enforcement of such standards;
- Enforceable increments of progress and milestones, as required for affected EGUs within a specific subcategory, included as enforceable elements of a state plan; and
- Identification of applicable monitoring, reporting, and recordkeeping requirements for affected EGUs.

The proposed emission guidelines include requirements pertaining to the methodologies states must use for establishing a presumptively approvable standard of performance for an affected EGU within a respective subcategory. These proposed methodologies are specified for each of the subcategories for affected EGUs.

The EPA notes that standards of performance for affected EGUs in a state plan must be representative of the level of emission performance that results from the application of the BSER in these emission guidelines. As discussed in section XI.C of this preamble, in order for the EPA to find a state plan “satisfactory,” that plan must achieve the level of emission performance that would result if each affected source was achieving its presumptive standard of performance, after accounting for any application of RULOF. That is, while states have the discretion to establish the applicable standards of performance for affected sources in their state plans, the structure and purpose of CAA section 111 require that those plans achieve an equivalent level of emission performance as applying the EPA’s presumptive standards of performance to those sources (again, after accounting for any application of RULOF).

The proposed emission guidelines also include requirements that apply to states when they invoke RULOF in applying a less stringent standard of performance for an affected EGU than result from the proposed methodology for establishing a presumptively approvable standard of performance. Such requirements include a demonstration by the state of why an affected EGU for which the state invokes RULOF cannot reasonably apply the BSER. The state must also demonstrate where and how it considered communities that may be affected by the establishment of a less stringent standard of performance for the identified affected EGU. This demonstration must include an identification of the affected communities, how the state considered the potential overall impact on the identified communities, a summary of feedback from meaningful engagement with the identified communities, and a demonstration of how the state considered the health and environmental impacts to the identified communities that would result from the establishment of a source-specific BSER for the identified affected EGU for which the state is invoking RULOF.

In addition to meaningful engagement with affected communities in the context of invoking RULOF, the proposed revisions to the CAA section 111 subpart Ba implementing regulations include requirements for public engagement on state plan development to ensure that communities most affected by and vulnerable to the health and environmental impacts of a plan will share in the benefits of the plan and are protected from being adversely impacted. These proposed requirements are in addition to the existing public notice requirements under subpart Ba and, if finalized, would apply to state plan development in the context of these emission guidelines. While the existing state plan development process provides opportunities for stakeholder input through notice and public hearing, the proposed revisions addressing meaningful engagement are designed to go further to ensure that such community concerns are heard in a more robust way than in the past and at critical junctures in the state plan development process, with state plan approval at stake.

The fundamental purpose of CAA section 111 is to reduce emissions from categories of stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan is the potential impact of the proposed plan requirements on public health and welfare. A robust and meaningful engagement process is critical to ensuring that the full range of health and environmental impacts of a proposed plan are understood and considered in the state plan development process.

In the subpart Ba revisions of December 2022, the EPA proposed to define meaningful engagement as:

> [T]timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate in favor of certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional,

> geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the state plan.[507]

The EPA proposed to define that pertinent stakeholders "include but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision."[508] The preamble to the proposed revisions to subpart Ba notes that "increased vulnerability of communities may be attributable, among other reasons, to both an accumulation of negative and lack of positive environmental, health, economic, or social conditions within these populations or communities."[509]

In the context of these emission guidelines, the air pollutant of concern is greenhouse gases and the air pollution is elevated concentrations of these gases in the atmosphere, which result in warming temperatures and other changes to the climate system that are leading to serious and life-threatening environmental and human health impacts. These impacts can have a disproportionate impact on communities and populations depending on, inter alia, accumulation of negative and lack of positive environmental, health, economic, or social conditions. The Agency therefore expects states' pertinent stakeholders to include not only owners and operators of affected EGUs but also communities vulnerable to the impacts of climate change, including those exposed to more extreme drought, flooding, and other severe weather impacts, including extreme heat and cold (states should refer to section III of this preamble, on climate impacts, to assist them in identifying their pertinent stakeholders). It is important for states to recognize and

[507] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.21a(k)).
[508] 87 FR 79176, 79191 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.21a(l)).
[509] 87 FR 79176, 79191 (December 23, 2022).

engage these communities, particularly as these communities may not have had a voice when the affected EGUs were originally constructed. Pertinent stakeholders should be able to provide input on how affected EGUs in their state comply with these emission guidelines. Providing input in this context means allowing communities to comment on the overall comprehensive compliance plan for all affected EGUs in a state, in contrast to permitting and other actions that focus on particular affected EGUs. Because these emission guidelines address air pollution that becomes well mixed and is long-lived in the atmosphere, pertinent stakeholders may include communities and populations that will be most affected by the overall stringency of state plans. (Note that the EPA addresses meaningful engagement in the context of RULOF for these emission guidelines in section XI.D.2.c of this preamble.)

In engaging with stakeholders in the development of these proposed emission guidelines, the EPA has heard concerns expressed over the use of CCS technology, including concerns related to the potential for steam generating units to prolong their lifespans through its use. While the EPA endeavored to address those concerns in part by basing the BSER on CCS only for those units that intend to operate in the long-term, the EPA is proposing to require that, if states are considering assigning affected EGUs to the long-term subcategory, the state must explicitly include CCS as part of meaningful engagement to ensure that concerns regarding CCS in particular can be voiced and heard through meaningful engagement. States would be required to demonstrate that they have designed meaningful engagement to elicit input from pertinent stakeholders on issues related to CCS. While the existing state plan development process provides opportunities for stakeholder input through notice and public hearing, the proposed revisions addressing meaningful engagement are designed to go further to ensure that such community concerns are heard in a more robust way than in the past and at critical junctures in the state plan development process, with state plan approval at stake.

If the revisions to subpart Ba are finalized as proposed, states would need to demonstrate in their state plans how they provided meaningful engagement with the pertinent stakeholders. This includes providing a list of the pertinent stakeholders, a summary of engagement conducted, and a summary of the stakeholder input provided. As previously noted, the state must allow for balanced participation, including communities most vulnerable to the impacts of the plan. States must consider the best way to reach affected communities, which may include but should not be limited to notification through the Internet. Other channels may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate. The state should also consider any geographic, linguistic, or other barriers to participation in meaningful engagement for members of the public. If a state plan submission does not meet the required elements for notice and opportunity for public participation, including requirements for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or to disapprove the plan. As discussed in section XI.F.2 of this preamble, the EPA is proposing an extension of the state plan submission timeline from 15 months to 24 months, which should allow states adequate time to conduct meaningful engagement.

The EPA is requesting comment on its proposal that CCS be a required part of meaningful engagement, as well as on whether there are any other specific technologies or aspects of state plan development around which the EPA should provide requirements for meaningful engagement. The EPA is also requesting comment on what assistance states and pertinent stakeholders may need in conducting meaningful engagement in the EGU context, including tools and methodologies for identifying communities that are most affected by and vulnerable to emissions from affected EGUs under these emission guidelines.

i. Specific State Plan Requirements for Transparency and Compliance Assurance

The EPA is proposing or requesting comment on several requirements designed to help states ensure compliance by affected EGUs with standards of performance, as well as to assist the public in tracking increments of progress toward the final compliance date.

First, the EPA is requesting comment on whether to require that an affected EGU's enforceable commitment to permanently cease operations, when that commitment is relied on for subcategory applicability (*e.g.*, an affected coal-fired steam-generating unit intends to rely on a committed date to permanently cease operations by December 31, 2034, to meet the applicability requirements for the near-term subcategory), must be in the form of an emission limit of 0 lb CO_2/MWh that applies on that date.[510] Such an emission limit would be included in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. If approved, the affected EGU would have a federally enforceable emission limit of 0 lb CO_2/MWh that would become effective as of the date that the EGU permanently ceases operations. The EPA is requesting comment on whether such an emission limit would have any advantages or disadvantages for compliance and enforceability relative to a federally enforceable commitment to cease operation by a date certain.

[510] As explained in section X.C of this preamble, an affected EGU's federally enforceable commitment to cease operations is not part of that EGU's standard of performance but is rather a prerequisite condition for subcategory applicability.

Second, the EPA is proposing that state plans that cover affected EGUs within any subcategory that is based on the date by which a source chooses to permanently cease operations(*i.e.*, imminent-term, near-term, medium-term) must include, in conjunction with an enforceable date, the requirement that each source comply with applicable state and federal requirements for permanently ceasing operation of the EGU, including removal from its respective state's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU.

Third, the EPA is proposing that each state plan must provide for the establishment of publicly accessible websites by the owners or operators of affected EGUs, referred to here as a "CAA Section 111(d) EGU Rule Website," to which all reporting and recordkeeping information for each affected EGU subject to the state plan would be posted. Although this information will also be required to be submitted directly to the EPA and the relevant state regulatory authority, the EPA is interested in ensuring that the information is made accessible in a timely manner to all pertinent stakeholders. The EPA anticipates that the owners or operators of affected EGUs may already be posting comparable reporting and recordkeeping information to publicly available websites under the EPA's April 2015 Coal Combustion Residuals Rule[511] such that the burden of this additional website requirement could be minimal.

In particular, the EPA is proposing that the owners or operators of affected EGUs would be required to post their subcategory designations and compliance schedules, including for increments of progress and milestones, leading up to full compliance with the applicable standards of performance. Owners/operators would also be required to post any information or

[511] See *https://www.epa.gov/coalash/list-publicly-accessible-internet-sites-hosting-compliance-data-and-information-required* for a list of websites for facilities posting Coal Combustion Rule compliance information.

documentation needed to demonstrate that an increment of progress or milestone has been achieved. Similarly, the EPA is proposing that emissions data and other information needed to demonstrate compliance with a standard of performance would also be required to be posted to the CAA Section 111(d) EGU Rule Website for an affected EGU in a timely manner. The EPA is proposing that all information required to be made publicly available on the CAA Section 111(d) EGU Rule Website be posted within 30 business days of the information becoming available to or reported by the owner/operator of an affected EGU. Information would have to be retained on the website for a minimum of 10 years. The EPA solicits comment on these timeframes for posting and information retention, as well as on any concerns related to confidential business information.

The EPA proposes that owners/operators of affected EGUs that are also subject to similar website reporting requirements for the Coal Combustion Residuals Rule may use an already established website to satisfy its CAA Section 111(d) EGU Rule Website requirements. The EPA solicits comment on other ways to reduce redundancy and burden while satisfying the objective of making it easier for pertinent stakeholders to access affected EGUs' reporting and recordkeeping information.

Fourth, to promote transparency and to assist the EPA and the public in assessing increments of progress under a state plan, the EPA is proposing that state plans must include a requirement that each affected coal-fired EGU must report any deviation from any federally enforceable state plan increment of progress or milestone within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. In the report, the owner or operator of the affected EGU would be required to explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. The owner or operator of the EGU must submit the report to the state regulatory agency and post the report to the affected EGU's CAA Section 111(d) EGU Rule Website.

Fifth, to aid all affected parties and stakeholders in implementing these emission guidelines, the EPA is explaining its intended approach to exercising its enforcement authorities to ensure compliance while addressing genuine risks to electric system reliability. The EPA has designed these proposed emission guidelines to accommodate the transitions that are currently occurring in the electric power sector, including through the structure of subcategories and provision of relatively long planning and compliance timeframes. The Agency therefore does not anticipate that either the need for certain coal-fired steam generating units to install controls or affected EGUs' preexisting decisions to permanently cease operations will result in resource constraints that would adversely affect electric reliability.

Nonetheless, the EPA acknowledges that there may be isolated instances in which unanticipated factors beyond an owner/operator's control, and ability to predict and plan for, could have an adverse, localized impact on electric reliability. In such instances, affected EGUs could find themselves in the position of either operating in noncompliance with approved, federally enforceable state plan requirements or halting operations and thereby potentially impacting electric reliability.

CAA section 113 authorizes the EPA to bring enforcement actions against sources in violation of CAA requirements, seeking injunctive relief, civil penalties and, in certain circumstances, other appropriate relief. The EPA also has the discretion to agree to negotiated resolutions, including administrative compliance orders ("ACOs") for achieving compliance with

CAA requirements, that include expeditious compliance schedules with enforceable compliance milestones. The EPA does not generally speak to the intended scope of its enforcement efforts, particularly in advance of a violation's actually occurring. However, the EPA is explaining its intended approach to ACOs here to provide confidence both with respect to electric reliability and that emission reductions under these emission guidelines will occur as required under CAA section 111(d).

The EPA would evaluate each request for an ACO for an affected EGU that is required to run in violation of a state plan requirement for reliability purposes on a case-by-case basis. However, as a general matter, the EPA anticipates that to qualify for an ACO, the owner/operator would need to demonstrate, as a minimum, that the following conditions have been satisfied:[512]

- The owner/operator of the affected EGU requesting an ACO has requested, in writing and in a timely manner, an enforceable compliance schedule in an ACO.
- The owner/operator of the affected EGU requesting an ACO has provided the EPA written analysis and documentation of reliability risk if the unit were not in operation, which demonstrates that operation of the unit in noncompliance is critical to maintaining electric reliability and that failure to operate the unit would result in violation of the reliability criteria required to be filed with FERC and, in the case of the Electric Reliability Council of Texas, with the Texas PUC, or cause reserves to fall below the required system reserve margin.

[512] This is a nonexclusive list of conditions. The EPA may choose to consider additional factors when deciding whether to enter an ACO in any given situation.

- The owner/operator of the affected EGU requesting an ACO has provided the EPA with written concurrence with the reliability analysis from the relevant electric planning authority for the area in which the affected EGU is located.
- The owner/operator of the affected EGU requesting an ACO has demonstrated that the need to continue operating for reliability purposes is due to factors beyond the control of the owner/operator and that the owner/operator of the affected EGU has not contributed to the purported need for an ACO.
- The owner/operator of the affected EGU requesting an ACO demonstrates that it has met all applicable increments of progress and milestones in the state plan.
- It can be demonstrated that there is insufficient time to address the reliability risk and potential noncompliance through a state plan revision.

If deemed appropriate to do so, the EPA would issue an ACO that includes a compliance schedule and milestones to achieve compliance as expeditiously as practicable. The ACO would also include any operational limits, including limits on utilization reflecting the extent to which the unit is needed for grid reliability, and/or work practices necessary to minimize or mitigate any emissions to the maximum extent practicable during any operation of the affected EGU before it has achieved full compliance. The EPA reiterates that it would not be appropriate to request an ACO to address reliability risk and anticipated noncompliance in circumstances in which a state plan revision is possible.

The EPA requests comment on whether to promulgate requirements in the final emission guidelines pertaining to the demonstrations, analysis, and information the owner/operator of an affected EGU would have to submit to the EPA in order to be considered for an ACO.

2. Timing of State Plan Submissions

The EPA's proposed subpart Ba revisions would require states to submit state plans within 15 months after publication of the final emission guidelines.[513] For the purpose of these particular emission guidelines, the EPA is proposing to supersede that timeline and is proposing a state plan submission deadline that is 24 months from the date of publication of the final emission guidelines. The EPA is superseding the proposed subpart Ba 15-month plan development and submission deadline for three reasons. First, these proposed emission guidelines apply to a complex and evolving source category. Making the decisions necessary for state plan development will require significant analysis, consultation, and coordination between states, utilities, ISOs or RTOs, and the owners or operators of individual affected EGUs. The power sector is subject to many layers of regulatory and other requirements under many authorities, and the decisions states make under these emission guidelines will necessarily have to accommodate many overlapping considerations and processes. States' plan development may be additionally complicated by the fact that, unlike some other source sectors to which the general CAA section 111 implementing regulations apply, decision-making regarding control strategies and operations for affected EGUs may not be solely within the purview of the owners or operators of those sources; at the very least, affected EGUs often must obtain permission before making significant or permanent changes. The EPA does not believe it is reasonable to expect states and affected EGUs to undertake the coordination and planning necessary to ensure that their plans for implementing these emission guidelines are consistent with the broader needs and trajectory of the power sector in the space of 15 months.

[513] See 87 FR 79182 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.23a(a)).

Second, and relatedly, the EPA believes that states and utilities need time to determine which subcategory and corresponding BSER is applicable for each affected EGU. Again, unlike some other source categories to which the CAA section 111 implementing regulations apply, the applicable subcategory for an affected EGU would depend on operational characteristics that are within the control of the EGU's owner/operator, subject to input from and requirements of ISO and RTOs and other authorities. Because an affected EGU may choose to change its operation in light of these emission guidelines, the process of determining the appropriate subcategory for each affected EGU is more complex than that for other source sectors to which subpart Ba applies. For any coal-fired EGU that chooses to permanently cease operations prior to 2040, the EPA anticipates that the owner or operator will be required to coordinate a date to cease operations with the corresponding RTO or ISO or other balancing authority to ensure proper retirement sequences and reliability. While the EPA expects that a number of affected EGUs already intend to cease operations at some point prior to 2040, under these emission guidelines states would require owners or operators to commit to an enforceable date to permanently cease operations for those EGUs. RTOs or ISOs or other balancing authorities will have to analyze potential impacts on the power sector and make decisions regarding these intended dates to permanently cease operations for the affected EGUs that are interested in committing to an enforceable date by which to permanently cease operations within a state plan submission. The EPA reiterates that, due to the rapid transition currently occurring in the power sector and due to the marginal nature of many affected EGUs, such changes in operation would be expected regardless of the particular requirements of these emission guidelines.

Third, prior to an owner or operator providing a suggestion for a subcategory and standard of performance for an affected EGU to a state, that owner or operator will likely need to analyze the potential feasibility of applying the applicable BSER for the subcategory. The EPA anticipates that EGUs that intend on operating beyond 2040 will do feasibility and FEED studies to ensure that CCS is appropriate prior to committing to that subcategory in a state plan. As discussed in section XI.B of this preamble and in the *GHG Mitigation Measures – 111(d)* TSD, FEED studies take approximately 12 months to complete,[514] after which additional time is necessary to allow the conclusions from that study to be integrated into a state's planning process for certain affected EGUs. For sources that intend to permanently cease operations before January 1, 2040, and that do not qualify for the imminent- or near-term subcategories, there are also planning, design, and permitting exercises that will be necessary for utilities to undertake prior to committing to a subcategory based on natural gas co-firing. While any boiler modifications required for affected EGUs that intend to co-fire natural gas are relatively straightforward, the owners/operators of EGUs in the medium-term subcategory may also be required to construct new pipelines to enable co-firing of 40 percent natural gas. Pipeline projects also require an initial planning and design process to determine feasibility and, in some cases, could involve FERC approval. Again, it may take 12 or more months for the owner/operator of an affected EGU to ascertain the feasibility of committing to the medium-term subcategory and to natural gas co-firing. Based on the approximately 12-month period that states and the owners/operators of affected EGUs will likely take to determine the feasibility of BSER control strategies for the long-term and medium-term subcategories, the EPA does not believe it is reasonable to require state plans to be submitted 15 months after promulgation of these emission guidelines.

[514] *GHG Mitigation Measures – 111(d)* TSD, chapter 4.7.1.

In the proposed subpart Ba timelines for state plan submission, the EPA justified the generally applicable timelines in the context of public health and welfare impacts by proposing timelines that are as quick as is reasonably feasible for a generic set of emission guidelines under CAA section 111(d). The EPA is proposing 24 months for state plan timelines for these emission guidelines because 24 months is the quickest time that the EPA believes to be reasonably feasible for a state to submit a state plan based on the work and evaluation needed to establish the viability of CCS and co-firing at a given coal-fired EGU. Additionally, the EPA does not believe providing a longer timeline for the submission of state plans would ultimately impact how quickly the affected EGUs can comply with their standards of performance. As explained in section XI.B of this preamble and in the *GHG Mitigation Measures – 111(d)* TSD, the EPA anticipates that CCS projects will take roughly 5 years to complete, assuming some steps are undertaken concurrently. If the EPA were to promulgate these emission guidelines in June 2024 and require state plan submissions in September 2025, the EPA anticipates that the soonest compliance could commence is in the third quarter of 2029. However, in this case, it is likely that at least some owners/operators of affected EGUs would have to commit to subcategories or control technologies before completing feasibility and FEED studies, which could result in the need for plan revisions and delayed emission reductions. In contrast, providing 24 months for state plan submission would mean that although plans would be due June 2026, owners/operators of affected EGUs would have had time to complete their feasibility and FEED studies and some initial planning steps before then. The EPA anticipates that owners/operators would need approximately another 3.5 years to reach full compliance, meaning that emission reductions would commence in the first quarter of 2030. The EPA does not believe that a difference of three months will adversely impact public health or welfare, especially when it is considered that providing more time for state plan development in this instance is more likely to ultimately result in certainty and timely emission reductions.

The EPA solicits comment on the 24-month state planning period. The EPA specifically requests comments from owners/operators of affected EGUs regarding the steps, and amount of time needed for each step, that they would have to undertake to determine the applicable subcategories and to plan and implement the associated control strategies for each of their affected EGUs. Additionally, the EPA requests comment on the 24-month planning period from states, including on any unique characteristics of the fossil fuel-fired EGU source category that they believe merit planning timeframes longer than 15 months. Through outreach, many states have expressed a need for longer planning periods and the EPA solicits comment on whether this 24-month planning period accommodates that need. The EPA also requests comment from potentially impacted communities and other pertinent stakeholders on any considerations related to providing a longer state plan submission timeframe under these emission guidelines.

3. State Plan Revisions

The EPA expects that the state plan submission deadline proposed under these emission guidelines would give states, utilities, and stakeholders sufficient time to determine in which subcategory each of the affected EGUs falls and to formulate and submit a state plan accordingly. However, the EPA also acknowledges that the power sector is rapidly evolving and that, despite states' best efforts to accurately reflect their utilities' intended paths forward at the time of plan submission, affected EGUs' plans may subsequently change. In general, states have the authority and discretion to submit revised state plans to the EPA for approval.[515] State plan revisions are generally subject to the same requirements as initial state plans under these

[515] 40 CFR 60.23a(a)(2), 60.28a.

emission guidelines and the subpart Ba implementation regulations, including meaningful engagement, and the EPA reviews state plan revisions against the applicable requirements of these emission guidelines in the same manner in which it reviews initial state plan submissions pursuant to 40 CFR 60.27a.

Approved state plan requirements remain federally enforceable unless and until the EPA approves a plan revision that supersedes such requirements. States and affected EGUs should plan accordingly to avoid noncompliance.

The EPA is proposing a state plan submission date that is 24 months after the publication of final emission guidelines and is proposing a compliance date of January 1, 2030. A state may choose to submit a plan revision within this period (*i.e.*, after it has submitted its initial state plan under these emission guidelines); however, the EPA reiterates that any already approved federally enforceable requirements, including milestones, increments of progress, and standards of performance, will remain in place unless and until the EPA approves the plan revision. The EPA requests comment on whether it would be helpful to states to impose a cut-off date for the submission of plan revisions ahead of the January 1, 2030, compliance date. Such a cut-off date, *e.g.*, January 1, 2028, would in effect establish a temporary moratorium on plan submissions in order to provide a sufficient window for the EPA to act on them ahead of the final compliance date. State plan revisions would again be permitted after the final compliance date. As an alternative to a cut-off date for state plan revisions ahead of the compliance date, the EPA requests comment on the dual-path standards of performance approach discussed in section XI.F.4 of this preamble.

Under these proposed emission guidelines, states would place their affected coal-fired EGUs into one of four subcategories based on the time horizons over which those EGUs intend to operate. These subcategories are static—affected EGUs would not be able move between subcategories absent a plan revision.[516] However, the EPA acknowledges that there may be instances in which a change in subcategory will be necessary. For affected coal-fired EGUs that are switching into the imminent-term, near-term, or medium-term subcategories, the EPA proposes to require that the state include in its state plan submission documentation of the affected EGU's submission to the relevant RTO or balancing authority of the new date it intends to permanently cease operations, any responses from and studies conducted by the RTO or balancing authority addressing reliability and any other considerations related to ceasing operations, any filings with the SEC or notices to investors in which the plans for the EGU are mentioned, any integrated resource plan, and any other relevant information in support of the new date. This documentation must be published on the CAA Section 111(d) EGU Rule Website. These proposed requirements are modeled on the proposed milestones for sources committing to permanently ceasing operations and are intended to help states, stakeholders, and the EPA ensure that the affected EGU's change in circumstances is sufficiently certain to warrant a state plan revision. Because of the long lead times for planning and implementation of control systems for affected EGUs, revising a state plan after the submission deadline has the potential to significantly disrupt states' and affected EGUs' compliance strategies. The EPA therefore believes it is reasonable to require affected EGUs and states to provide evidence that a source's circumstances have in fact changed, in order for the EPA to approve a plan revision. Affected EGUs switching into the imminent-term, near-term, or medium-term subcategories would also

[516] If the EPA finalizes an option for states to include dual paths for an affected coal-fired EGU or EGUs in their state plans, those affected EGUs would be able to choose between two subcategories prior to the final compliance date without the state's needing to revise its plan.

be required to comply with the proposed enforceable milestones applicable to those subcategories.

Some changes between subcategories, including from the long-term into the medium-term subcategory and from the imminent-term or near-term into the medium-term or long-term subcategory, would entail new standards of performance reflecting a different add-on control strategy than initially anticipated. In order to avoid undermining the stringency of these proposed emission guidelines, the EPA expects affected EGUs changing subcategories before the January 1, 2030, compliance deadline to make every reasonable effort to meet that compliance deadline. However, the EPA acknowledges that, in some circumstances, it may not be possible to complete the necessary planning and construction within a shortened timeframe. Additionally, unforeseen circumstances could require some affected EGUs to change subcategories after the final compliance deadline has passed (*e.g.*, to ensure reliability).

In these circumstances, the EPA is proposing that states may use the RULOF mechanism described in section XI.D.2 of this preamble to adjust the compliance deadlines for affected EGUs that cannot comply with their applicable standards of performance by the January 1, 2030, deadline. The EPA expects that states may be able to demonstrate that the change in subcategory constitutes an "other circumstance[] specific to the facility . . . that [is] fundamentally different from the information considered in the determination of the best system of emission reduction in the emission guidelines."[517] In order to invoke RULOF to change a compliance deadline for an affected EGU that has switched subcategories, the EPA proposes that the state must first demonstrate that the affected EGU cannot meet the applicable presumptive standard of

[517] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions to RULOF provisions at 40 CFR 60.24a(e)(3)).

performance by the compliance deadline in these emission guidelines. As part of this demonstration the state would be required to provide evidence supporting the affected EGU's need to switch subcategories. The state would also be required to demonstrate that the need to invoke RULOF and to provide a different compliance deadline or less stringent standard of performance was not caused by self-created impossibility. Documentation related to these demonstrations must also be posted to the CAA Section 111(d) EGU Rule Website. For example, it would not be reasonable for a state that has been notified that an RTO requires an affected EGU to switch subcategories to wait to revise its SIP until the remaining useful life of that EGU is so short as to preclude otherwise reasonable systems of emission reduction. To this end, the EPA is proposing to consider when a state knew or should have known that an affected EGU would need to switch subcategories when evaluating the approvability of state plans that include RULOF demonstrations. The EPA is additionally proposing to consider whether an affected EGU has been complying with its applicable milestones and increments of progress when evaluating RULOF demonstrations. The EPA encourages states to consult with their EPA Regional Offices as early as possible if they believe it may become necessary for an affected EGU to switch subcategories. The EPA requests comment on whether to set a deadline for states to provide plan revisions within a certain timeframe of knowing that an affected EGU needs to switch subcategories and on what timeframe would be appropriate.

The EPA is proposing that states invoking RULOF because an affected EGU cannot comply with its newly applicable presumptive standard of performance by the final compliance deadline first evaluate whether the affected EGU is able to comply with that standard by a different, later-in-time deadline. If a state can demonstrate that an affected EGU cannot reasonably comply with the applicable presumptive standard of performance under any reasonable compliance deadline, it may then evaluate different systems of emission reduction according to the proposed RULOF mechanism described in section XI.D.2 of this preamble.

4. Dual-Path Standards of Performance for Affected Coal-Fired Steam Generating Units

Under the structure of these emission guidelines as proposed, states would assign affected coal-fired EGUs to subcategories in their state plans and an EGU would not be able to change its applicable subcategory without a state plan revision. This is because, due to the nature of the BSERs for coal-fired EGUs, an EGU that switches between subcategories may not be able to meet compliance obligations for a new and different subcategory without considerable lag time and thus the switch would result in noncompliance and a loss of emission reductions. Therefore, as a general matter, states must assign each affected EGU to a subcategory and have in place all the measures necessary to implement the requirements for that subcategory by the time of state plan submission.

However, the EPA acknowledges that there may be circumstances in which a coal-fired EGU wishes to retain the option to choose between two different subcategories ahead of the proposed January 1, 2030, compliance date. The EPA is therefore soliciting comment on the following dual-path approach that may result in an additional flexibility for owners/operators of affected coal-fired EGUs that want additional time to commit to a particular subcategory without the need for a state plan revision.

The EPA is soliciting comment on an approach that allows coal-fired EGUs to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories. A state plan would be required to have all the associated components for each subcategory. For example, for an affected EGU that wants the option to be part of either the long-term or imminent-term subcategory, the state plan would include a standard of performance based on implementation of CCS and associated requirements, including increments of progress; as well as an enforceable requirement to permanently cease operations before January 1, 2033, and a standard of performance based on routine operation and maintenance. The affected EGU would be required to meet all compliance obligations for both subcategories, including increments of progress and/or milestones for federally enforceable commitments to cease operations, leading up to the compliance date of January 1, 2030. The state and affected EGU would be required to choose a subcategory for the affected EGU ahead of that date. Specifically, the EPA is proposing that the state must notify the EPA of its final applicable subcategory and standard of performance at least 6 months prior to the compliance date (*i.e.*, the state would have to notify the EPA of the applicable standard by July 1, 2029). If the state has not notified the EPA by July 1, 2029, of the final applicable subcategory for the affected EGU, the EPA is proposing that that EGU would automatically be subject to the requirements of the subcategory that corresponds to the longer remaining life of the EGU. Additionally, if the affected EGU misses an enforceable increment of progress, milestone (as described in section XI.D.3 of this preamble), or any other requirement for one of the two subcategories, the EGU will automatically be subject to the requirements of the other subcategory. If the EGU misses submissions for increments of progress/milestones for both subcategories, the EGU will automatically be subject to the requirements of the subcategory that corresponds to the longer remaining life of the EGU and will additionally be found to be out of compliance for the increment of progress or milestone that it has missed.

The EPA is soliciting comment on this approach to provide flexibility to states and affected EGUs. In some instances, owners of affected EGUs may wish to have additional time to decide on a control strategy; this proposed dual-path approach should provide utilities an additional 3 years to commit to a subcategory. However, with this additional time comes additional burden on owners and operators to demonstrate compliance with each of the requirements associated with two different subcategories that would be included in a state plan. As an example, a coal-fired EGU intends to cease operations between 2038 and 2041. The state plan is submitted and contains two different enforceable dates to permanently cease operations, *e.g.*, December 31, 2038, with a standard of performance based on natural gas co-firing and December 31, 2041, with a standard of performance based on CCS, as well as an enforceable commitment by the state to choose one path or the other by July 1, 2029. The affected EGU would then be required to comply with the increments of progress for both the long-term (CCS) and medium-term (co-firing) subcategories, until the point at which the state decides which of the two paths in its plan it will require for the unit.

The EPA solicits comment on whether this proposed dual-path flexibility would have utility and on whether it could be implemented in a manner that ensures that states and affected coal-fired EGUs would be able to comply with applicable requirements in a timely manner. Additionally, the EPA solicits comment on whether July 1, 2029, is the appropriate date for a final decision between the two potential standards of performance and why.

5. EPA Action on State Plans

Pursuant to proposed subpart Ba, the EPA would use a 60-day timeline for the Administrator's determination of completeness of a state plan submission[518] and a 12-month timeline for action on state plans.[519] The EPA's review of and action on state plan submissions

[518] The timeframes and requirements for state plan submissions described in this section also apply to state plan revisions. See generally 40 CFR 60.27a.
[519] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.27a).

would be governed by the requirements of revised subpart Ba. First, the EPA would review the components of the state plan to determine whether the plan meets the completeness criteria of 40 CFR 60.27a(g). The EPA must determine whether a state plan submission has met the completeness criteria within 60 days of its receipt of that submission. If the EPA has failed to make a completeness determination for a state plan submission within 60 days of receipt, the submission shall be deemed, by operation of law, complete as of that date.

Proposed subpart Ba would require the EPA to take action on a state plan submission within 12 months of that submission's being deemed complete. The EPA will review the components of state plan submissions against the applicable requirements of subpart Ba and these emission guidelines, consistent with the underlying requirement that state plans must be "satisfactory" per CAA section 111(d). If the EPA finalizes the revisions to subpart Ba as proposed, the Administrator would have the option to fully approve, fully disapprove, partially approve, partially disapprove, and conditionally approve a state plan submission.[520] Any components of a state plan submission that the EPA approves become federally enforceable.

The EPA requests comment on the use of the timeframes provided in subpart Ba, as the EPA has proposed to revise it, for EPA actions on state plan submissions and for the promulgation of Federal plans for these particular emission guidelines.

6. Federal Plan Applicability and Promulgation Timing

The provisions of subpart Ba, including any revisions the EPA finalizes pursuant to its December 2022 proposal, will apply to the EPA's promulgation of any Federal plans under these emission guidelines. The EPA's obligation to promulgate a Federal plan is triggered in three

[520] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.27a(b)).

situations: where a state does not submit a plan by the plan submission deadline; where the EPA determines that a state plan submission does not meet the completeness criteria and the time period for state plan submission has elapsed; and where the EPA fully or partially disapproves a state's plan.[521] Where a state has failed to submit a plan by the submission deadline, the EPA has 12 months from the state plan submission due date to promulgate a Federal plan; otherwise, the 12-month period starts from the date the state plan submission is deemed incomplete, whether in whole or in part, or from the date of the EPA's disapproval. The EPA may approve a state plan submission that corrects the relevant deficiency within the 12-month period, before it promulgates a Federal plan, in which case its obligation to promulgate a Federal plan is relieved.[522] As provided by 40 CFR 60.27a(e), a Federal plan will prescribe standards of performance for affected EGUs of the same stringency as required by these emission guidelines and will require compliance with such standards as expeditiously as practicable but no later than the final compliance date under these guidelines. However, upon application by the owner or operator of an affected EGU, the EPA in its discretion may provide for a less stringent standard of performance or longer compliance schedule than provided by these emission guidelines, in which case the EPA would follow the same process and criteria in the regulations that apply to states' provision of RULOF standards.[523] Under the proposed revisions to subpart Ba, the EPA would also be required to conduct meaningful engagement with pertinent stakeholders prior to promulgating a Federal plan.[524]

[521] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.27a(c)).
[522] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.27a(d)).
[523] 40 CFR 60.27a(e)(2).
[524] 87 FR 79176 (December 23, 2022), Docket ID No. EPA-HQ-OAR-2021-0527-0002 (proposed revisions at 40 CFR 60.27a(f)).

As described in section XI.F.2 of this preamble, the EPA is proposing to allow states 24 months for a state plan submission after the promulgation of the final emission guidelines. Therefore, the EPA would be obligated to promulgate a Federal plan for all states that fail to submit plans within 36 months of the final emission guidelines. Note that this will be the earliest obligation for the EPA to promulgate Federal plans for states and that different triggers (*e.g.*, a disapproved state plan) will result in later obligations to promulgate Federal plans contingent on when the obligation is triggered.

Under the Tribal Authority Rule (TAR) adopted by the EPA, tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to that of a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to that of a state for purposes of developing a Tribal Implementation Plan (TIP) implementing the emission guidelines. If a tribe obtains approval and submits a TIP, the EPA will generally use similar criteria and follow similar procedures as those described for state plans when evaluating the TIP submission and will approve the TIP if appropriate. The EPA is committed to working with eligible tribes to help them seek authorization and develop plans if they choose. Tribes that choose to develop plans will generally have the same flexibilities available to states in this process. If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for areas of Indian country where designated facilities are located. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves an applicable TIP applicable to those facilities.

XII. Solicitation of Comments on Emission Guidelines for Existing Fossil Fuel-fired Stationary Combustion Turbines

A. Overview

Because the EPA has established NSPS for GHG emissions from new fossil fuel-fired stationary combustion turbines under CAA section 111(b), it has an obligation to also establish emission guidelines for GHG emissions from existing fossil-fuel fired stationary combustion turbines under CAA section 111(d). The EPA intends to fulfill that obligation as expeditiously as practicable. In addition to the CAA obligation, the EPA believes that it is important to address emissions from existing fossil-fuel fired stationary combustion turbines expeditiously, because they are quickly becoming the biggest source of GHG emissions from EGUs. As other fossil-fuel EGUs reduce utilization or retire, at least some of this generation may shift to the existing combustion turbine fleet, particularly if the latter is not subject to limits on GHG emissions. Indeed, the EPA's modeling for these proposed rules indicate that GHG emissions from these units may increase by a material amount in the 2030 to 2035 timeframe in part as a result of a shift in generation to existing combustion turbines associated with the NSPS and emission guidelines proposed in these actions.

In considering how to address this problem, the EPA believes there are at least two key factors to consider. The first is that determining the BSER and issuing emission guidelines covering these units sooner rather than later is important to address the GHG emissions from this growing part of the inventory. The second is related to the size of the affected fleet and the implications for the feasibility and timing of implementing potential candidates for BSER. As discussed later in this section, there are at least three technologies that could be applied to reduce GHGs from existing combustion turbines (CCS, hydrogen co-firing, and heat rate improvements), all of which are available today and are being pursued to at least some degree by owners and operators of these sources. Although the EPA believes that these technologies are available and adequately demonstrated at the level of individual existing combustion turbines, emission guidelines for these sources must also consider how much of the fleet could reasonably implement one or more of these potential BSER approaches in a given time frame.

To provide a sense of scale, the EPA projects that there will be 60 GW of coal-fired steam generating units and 60 GW of oil-/natural gas-fired steam generating units operating in 2030 that will be subject to the CAA section 111(d) requirements for existing fossil fuel-fired steam generating units and 47 GW of new turbines subject to the CAA section 111(b) standards of performance that are proposed in this document. In other words, in 2030, the EPA anticipates there would be nearly three times as many units (414 GW) subject to an emission guideline for existing fossil fuel-fired combustion turbines as would already be covered by the proposed NSPS and emission guidelines in these actions.

Furthermore, the EPA is aware that grid operators and power companies currently rely on existing fossil fuel-fired combustion turbines as a flexible and readily dispatchable resource that plays a key role in fulfilling resource adequacy and operational reliability needs. Although advancements in energy storage and accelerated development and deployment of zero emitting resources may diminish reliance on existing fossil fuel-fired combustion turbines for reliability purposes over time, it is imperative that emission guidelines for these sources not impair the reliability of the bulk power system. For these reasons, the EPA believes that it is important that a BSER determination and associated emission guidelines for existing fossil fuel-fired combustion turbines rely on GHG control options that can be feasibly and cost-effectively implemented at a scale commensurate with the size of the regulated fleet, and provide sufficient lead time to allow for smooth implementation of the GHG emission limitations that preserves system reliability. Given the large size of the existing combustion turbine fleet and the lead time required to develop CCS and hydrogen-related infrastructure, the EPA believes it would be particularly challenging to implement a BSER that requires near-term, wide-scale deployment of CCS or low-GHG hydrogen co-firing at these sources.

As a result, the EPA is considering breaking the existing turbine category into two segments and focusing an initial rulemaking effort on the most frequently operated and therefore highest-emitting turbines, to be followed by a separate rulemaking at a later time that addresses emissions from the remaining turbines as well as additional opportunities to reduce emissions from those units regulated in the first rulemaking. In this notice, the EPA is soliciting comment on the general concept of conducting two rulemakings and developing a BSER for the most frequently operated and highest emitting turbines in a timeframe that would allow for emission reductions in the 2030-2035 window, potentially mitigating the emissions increases in that timeframe. If the BSER for those units were based on the use of CCS, establishing emission guidelines that required limits on GHG emissions in the 2030-2035 timeframe would also allow those units to take advantage of the IRC section 45Q tax credits to make these controls more cost-effective. In the rest of this section, the EPA outlines what such an approach might look like and solicits comment on specific elements of the approach. This section also briefly discusses what BSER might look like for units in the second rulemaking, noting that under this approach, the EPA would likely develop a rulemaking defining BSER for those units at a later date.

The EPA's approach for units covered by the first rulemaking would be on a schedule similar to the proposed schedule for requirements for existing fossil fuel-fired steam generating units (*i.e.*, with compliance deadlines falling in or not long after 2030), with emissions limitations based on heat rate/efficiency improvements, co-firing low-GHG hydrogen, and/or use of CCS for the most frequently operated and highest-emitting units. For units covered by the second rulemaking, requirements based on one or more of these technologies would also apply. As part of this follow-up rulemaking, the EPA could also consider establishing more stringent emission guidelines for certain units that are covered in the first rulemaking, but which are not required to significantly reduce emissions by that rulemaking due to concerns over the lead time required to build out CCS and hydrogen infrastructure. This approach would allow time for the infrastructure to implement CCS and co-firing low-GHG hydrogen to further develop. The EPA may implement this approach by subcategorizing combustion turbines based on their efficiency, the frequency with which they operate, their size, and whether they are located close to sequestration sites.

Section XII.B provides background information concerning the composition of the current fossil fuel-fired stationary combustion turbine fleet and how it is expected to change in the near future. In section XII.C the EPA outlines the potential approach for units covered in the first rulemaking and in section XII.D, outlines a potential approach for units covered in the second rulemaking. In section XII.E, the EPA discusses potential state plan requirements. Finally, in section XIII.F, the EPA summarizes the key topics for which we are soliciting comment relative to existing combustion turbines.

B. The Existing Stationary Combustion Turbine Fleet

In 2021, existing combustion turbines represented 37 percent of the GHG emissions from the power sector and 40 percent of the generation from the power sector. In the EPA's updated baseline projections for the power sector, they represent 64 percent of the GHG emissions and 34 percent of the generation in 2030. In EPA's modeling of the 2030 control case, in which both existing fossil fuel-fired EGUs and new stationary combustion turbine EGUs are subject to the emissions limitations proposed in this action, load shifting from those two categories of sources to the existing combustion turbines results in an increase in the share of the emissions from existing combustion turbines to 68 percent and an increase in their share of generation to 36 percent. Moreover, in that control case, existing combined cycle combustion turbines are responsible for 65 percent of the CO_2 emissions from existing stationary combustion turbines.

In the EPA's modeling in support of these rules, we see two trends that are important relative to existing combustion turbines. First, the EPA's analysis of the reference case (which includes the impacts of IRA without considering the GHG limitation requirements proposed in these rules) projects a long-term decline in generation and emissions from existing combustion turbines. In this reference case, combined cycle generation falls in each model run year from 2028 through 2050, and it falls by more than 50 percent between 2030 and 2045. Generation from existing simple cycle combustion turbines is projected to peak in 2030 before declining by more than 70 percent by 2045.

Historical data shows a wide range of variation in both the heat rate and the GHG emission rates among both existing combined cycle combustion turbines and existing simple cycle combustion turbines. The GHG emission rates for existing combined cycle units range from as low as 644 lb CO_2/MWh-gross to as high as 1,891 lb CO_2/MWh-gross and annual capacity factors range from as low as 1 percent to as high as 85 percent. While there is some correlation between units with low-GHG emission rates (*e.g.*, more efficient units) and utilization, some low efficiency combined cycle units have historically operated at very high capacity factors. For instance, two of the highest operating units (at 85 percent capacity utilization) have GHG emission rates of nearly 1,200 lb/MWh-gross.

C. BSER for Frequently-Operated Existing Combustion Turbines

The EPA is soliciting comment on a potential approach for regulating GHG emissions from existing combustion turbines in two rulemakings, with a BSER based on heat rate/efficiency improvements, CCS, and co-firing low-GHG hydrogen. This approach recognizes the imperatives (the urgent need to reduce greenhouse gases), the opportunities (including the availability of IRC section 45Q tax credits incentivizing CCS installation and section 45V tax credits for low-GHG hydrogen, as long as sources commence construction by January 1, 2033), and the obstacles (the need for infrastructure for CCS and co-firing low-GHG hydrogen to more fully develop).

As part of this approach, the EPA would subcategorize combustion turbines based on characteristics that are relevant for the types of controls that the EPA may identify as the BSER. These characteristics could include the level of efficiency with which the combustion turbines operate, their size, their level of utilization, their announced retirement date (if any), and whether they are located near sequestration sites.

For units covered in the first rulemaking, the EPA would establish emission guidelines specifying the BSER and the level of emission reduction that sources could comply with during an approximately 2029-2035 timeframe, consistent with the requirements for new combustion turbines. In establishing applicability requirements for sources covered in this first rulemaking, the EPA would focus primarily on the most frequently operated units (*e.g.,* those above a capacity factor threshold of 50 to 60 percent). Such units would likely be combined cycle units, which account for the vast majority of generation and GHG emissions from existing fossil fuel-fired combustion turbines. At a 50 percent capacity factor threshold, approximately 68 percent of the current combined cycle capacity would be covered. At a 60 percent capacity factor threshold, approximately 62 percent of the capacity would be covered. In the second rulemaking, the EPA would address all units that were not covered in the initial rulemaking and could also establish more stringent requirements for certain units covered in the first rulemaking.

The EPA believes this approach would ensure that GHG emissions limitations are implemented first at the subset of existing fossil fuel-fired combustion turbines that contributes the most to GHG emissions, and where the benefits of implementing GHG controls would be greatest. In 2030, more than half of the generation and emissions from existing fossil fuel fired combustion turbines are projected to come from units that operate at a capacity factor greater than 50 percent.

The EPA believes there are three sets of controls that could potentially qualify as the BSER for the group of large and frequently-operated combustion turbines covered in the first rulemaking. Those controls are heat rate/efficiency improvements, co-firing low-GHG hydrogen, and use of CCS.

The EPA believes that heat rate improvements for existing combustion turbines are broadly applicable today. Heat rate/efficiency improvements can be divided into two types. The first type involves smaller scale improvements to existing combustion turbines. The second type involves more comprehensive upgrades of the combustion turbines.

Smaller scale efficiency improvements can include measures such as inlet fogging and inlet cooling. Both of these techniques can achieve about 2 percent improvements in heat rate. Inlet chilling costs approximately $19/kW and is also accompanied by a capacity increase of 11 percent. Inlet fogging is approximately $0.93/kW and is accompanied by a capacity increase of 6 percent.[525] The EPA believes that if it did develop a subcategory for which small-scale efficiency

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[525] *https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.*

improvements were identified as the BSER, it would likely result in an average 2 percent improvement in the heat rate of affected existing combustion turbines.

More comprehensive efficiency upgrades to combustion turbines are also possible. There is growing evidence that companies are interested in retrofitting existing combustion turbines. An upgrade to the combustion turbine can result in a heat rate improvement of 3.0 percent and a capacity increase of 13 percent for $172/kW, while an upgrade to the steam turbine can result in a heat rate improvement of 3.2 percent with a capacity increase of 3 percent for $130/kW. The EPA believes that if it did develop a subcategory for which more comprehensive efficiency improvements was identified as the BSER, it would likely result in an average efficiency improvement of 6 percent for affected existing stationary combustion turbines.

Although the EPA has proposed to reject efficiency/heat rate improvements (HRI) as the BSER for coal-fired steam generating units, it did so for two reasons that do not apply in the case of combustion turbines. First, for coal-fired steam generating units, HRI achieves only a small amount of emission reductions. For combustion turbines, HRI could constitute an important first step for units that may ultimately adopt co-firing with low-GHG hydrogen or use of CCS as these technologies become more widely implemented and deployed. Because co-firing low-GHG hydrogen and adopting CCS are most cost effective at units that are operating at peak efficiency, combustion turbines that plan to ultimately adopt these controls are likely to implement HRI as well.

Second, for coal-fired steam generating units, HRI could lead to a rebound effect that would result in increased emissions. HRI for combustion turbines could also result in a rebound effect, but that would not necessarily increase emissions and, in fact, could decrease them. Coal-fired steam generating units are the highest GHG intensity units; so if such a unit increases its utilization, it is almost certainly offsetting generation from a unit with similar GHG emissions, such as another coal-fired steam generating unit, or a unit with lower GHG emissions, such as a natural gas-fired combustion turbine or some other low-GHG emitting generation. This is not necessarily the case with a combined cycle unit. If a combined cycle unit becomes more efficient and operates more, it is likely to offset emissions from a higher emitting unit, such as a coal-fired unit, or even an efficient simple cycle turbine. This is especially true because many efficiency improvements also increase capacity, and with increased capacity, combined cycle units will have an even larger ability to displace other generation.

The second potential BSER that the EPA is considering is co-firing low-GHG hydrogen. As discussed in section VII, co-firing with low-GHG hydrogen is feasible in combustion turbines that are currently being produced and can achieve meaningful reductions in GHG emissions from these sources. In section VII, the EPA proposes the use of low-GHG hydrogen as BSER for certain new base load turbines, but the EPA also solicits comment on whether limiting the use of low-GHG hydrogen to less frequently operated turbines should be considered for the following reason. Low-GHG hydrogen may be used across wide swaths of the economy, including in the transportation sector, industrial applications, and power generation. Some stakeholders in the power generation sector have suggested that low-GHG hydrogen use in that sector should be focused on energy storage applications, rather than base load applications, in light of the likely large overall demand for low-GHG hydrogen and the large energy demands associated with its production. For this reason, the EPA is considering whether co-firing with low-GHG hydrogen should be considered as a BSER option for less-frequently operated existing fossil fuel-fired combustion turbines, rather than for the most frequently operated units for which the EPA would initially be establishing emission guidelines. The EPA takes comment on whether it should consider a BSER subcategory including hydrogen co-firing for frequently used turbines.

The third set of controls that the EPA is considering is the use of CCS. The EPA believes that CCS could be a potentially effective mitigation measure for existing combustion turbines and that it would be most cost-effective for units that are frequently operating and that are in geographic locations with access to sequestration. As discussed in section VII, multiple companies are considering adding CCS to existing fossil fuel-fired power plants. The EPA believes that a number of existing combined cycle units are likely to be able to install and operate CCS within the costs that the EPA found to be reasonable for new stationary combustion turbines and existing coal-fired steam generating units. These are units that are large, have higher capacity factors, and are located close sequestration sites. The EPA estimates that there are approximately 18 GW of combined cycle facilities that are over 500 MW in size, operate at a capacity factor of over 50 percent, and are located in a state with identified deep saline reservoir sequestration sites. There are approximately 10 GW of units that meet those criteria and operate at a capacity factor of over 60 percent.

Based on the above discussion, the EPA is soliciting comment on whether in its first rulemaking to define a subcategory of units and establish emission guidelines based on CCS as the BSER for that subcategory. The EPA is also taking comment on what the appropriate characteristics for such a category should be. Above, the EPA describes one potential subcategory definition. The EPA anticipates that such a subcategory would likely represent only a small percentage of the units with projected capacity factors of over 50 percent. For the remaining frequently operated units, the EPA is seeking comment on whether it would be appropriate to consider one or more additional subcategories for which BSER would be based on heat-rate efficiency improvements or co-firing with low-GHG hydrogen. For the reasons explained above, the EPA is soliciting comment on whether it would be appropriate to have two subcategories where efficiency improvement is identified as the BSER. The first subcategory would be for units with high capacity factors and relatively high heat rates. For such units, the EPA is requesting comment on the BSER being a major combustion turbine overhaul that would result in a heat rate improvement of at least 6 percent. The EPA is soliciting comment on defining this subcategory to include units operating at a capacity factor over 50 percent and with a heat rate higher than 8,300 Btu/kwh. At this level, the most efficient units in the subcategory would be required to achieve a new heat rate of 7,800 Btu/kwh, slightly higher than the heat rate requirement for new stationary combustion turbines. For units above a capacity factor of 50 percent (or 60 percent) that are not subject to a BSER of CCS or major efficiency improvements, the EPA would likely consider a BSER of minor heat rate improvements that would require a heat rate improvement of 2 percent. The EPA is also taking comment on whether this heat rate improvement should include a floor of 7,800 Btu/kwh.

D. BSER for Remaining Combustion Turbines

While the EPA believes that emission guidelines for units covered in the first rulemaking, described above, can achieve important emission reductions from the most frequently operating turbines, limited infrastructure prevents widespread adoption of co-firing low-GHG hydrogen or CCS in that rulemaking. In this section, the EPA discusses how developing a BSER for units in the second rulemaking could address additional units that do not install CCS or co-fire significant amounts of low-GHG hydrogen under the emission guidelines for frequently operating turbines, as well as units that do not meet the applicability requirements for the first rulemaking. In this follow-up rulemaking, the EPA could also consider establishing emission guidelines for sources that are covered by the new source standards that are being proposed but that would continue to emit relatively large amounts of CO_2 on a lb/MWh basis including intermediate units subject to a BSER based on 30 percent hydrogen co-firing and low load units that are meeting a clean fuels standard. This second rulemaking might impose requirements on sources beginning in 2035. The second rulemaking would extend CCS and co-firing low-GHG hydrogen to additional combustion turbines.

As noted in section XII.C, the EPA believes that a first rulemaking for existing turbines would apply to units most amenable to CCS, which ensures that any limits on the amount of CCS that could be installed during the relatively short timeframe of the first rulemaking, that is, by 2032, are taken into account. The second rulemaking would provide an opportunity for the EPA to consider whether CCS could be considered BSER for a larger number of frequently used turbines due to the further development of CCS infrastructure, including pipelines and additional sequestration sites, as well as potential cost reductions in capture equipment. For example, based on updated information, the EPA could consider whether CCS is the BSER for facilities that meet somewhat lower size or capacity thresholds, or are located somewhat more distant from sequestration sites, than units for which CCS is determined to be the BSER in the first rulemaking.

Furthermore, in the second rulemaking, the EPA would establish emission guidelines for any existing combustion turbines that are not covered by the emission guidelines promulgated in the first rulemaking – namely, less frequently operated turbines. The EPA anticipates that these less frequently operated turbines would consist principally of simple cycle combustion turbines. As explained above in section XII.C, the EPA believes that, absent significant further reductions in the cost of CCS, it is unlikely that CCS would meet the cost criteria used in these proposed actions as a reasonable cost for BSER for less frequently used turbines. Therefore, the EPA believes the second rulemaking would likely consider whether expanding co-firing low-GHG hydrogen is BSER for less frequently operated turbines. This could entail some combination of including more units in a co-firing low-GHG hydrogen based BSER (*e.g.*, peaking turbines) and/or expanding the co-firing percentage to an amount greater than 30 percent. This concept of moving from 30% co-firing of hydrogen to larger amounts of hydrogen over time is consistent with many companies' stated plans. For instance, the developers of the Intermountain Power Project indicate that they intend to combust 30 percent hydrogen when their unit (currently under construction) commences operation in 2025. They intend to transition to use of 100 percent hydrogen by 2045 as technology improves.[526] Most turbine manufacturers are developing technologies to co-fire amounts of hydrogen that are substantially larger than 30 percent.[527] Many of these manufacturers are developing retrofit options for existing turbines to run on large percentages of hydrogen, even up to 100 percent.[528] Given these rapid advancements in combustion turbine technology, the EPA believes that the key driver for how much hydrogen could be co-fired in turbines, particularly those operating at less than base load (*e.g.,* 50 percent), is more likely related to how quickly low-GHG hydrogen production and distribution will expand to provide the needed low-GHG hydrogen, rather than the physical capabilities of turbines to combust it.

[526] *https://www.ipautah.com/ipp-renewed/*.
[527] *https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/*.
[528] *https://www.ge.com/news/reports/the-great-retrofit-how-thousands-of-natural-gas-turbines-could-potentially-run-on-carbon* and *https://power.mhi.com/special/hydrogen*.

E. State Plan Requirements for Existing Turbines

This section focuses on three specific state plan requirements: 1) setting emission standards consistent with BSER; 2) Remaining Useful Life and Other Factors (RULOF) and 3) Flexibilities and State Equivalency. It also has a brief discussion of other state plan requirements.

In the emissions guidelines, the EPA would require state plans to establish emission standards consistent with application of the BSER, similar to what section XI describes for fossil fuel-fired steam generating units. The first step would involve setting a baseline emission rate using historical data. The second step would be to adjust that emission rate to reflect the level of reductions expected with implementation of BSER. For example, if the BSER for a major turbine upgrade was based on a 6 percent heat rate improvement, the state would be required to establish emission standards that reduce the baseline emission rate by 6 percent.

The application of the RULOF provision could be important for states with respect to certain turbines. The useful life of a combined cycle unit is approximately 25 to 30 years[529], and because more than 151 GW of combined cycle units came on-line in the 2000 to 2010 time-frame[530], many could potentially be at or nearing the end of their remaining useful life in the 2030 to 2040 timeframe. The EPA anticipates that states would be required to apply the RULOF provision similar to the way that the EPA is proposing it be applied for existing fossil fuel-fired steam generating units. Thus, any retirement date that was considered in establishing a less stringent standard for the facility would need to be made federally enforceable. In addition, the state would be required to determine the source-specific BSER for the facility by evaluating the

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[529] *https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf*.
[530] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v6. October 2022. See *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*.

same factors that the EPA considered. For example, for a unit subject to a presumptive standard based on CCS pursuant to the emission guidelines, the state would first consider alternative standards based on CCS with a lower carbon capture rate, then co-firing with low-GHG hydrogen, then comprehensive turbine upgrades, and finally smaller scale efficiency improvements.

There are at least two areas where we anticipate states and sources being interested in additional flexibilities beyond those available through the RULOF provisions. First, states and sources have expressed significant interest in emission trading. As the EPA has explained earlier in this preamble, the Agency believes that, because so many coal-fired units are likely to cease operations in the 2030 to 2040 timeframe in the baseline, an emission trading program for those units would have significantly less utility. However, because many turbines have come on-line since 2015, have remaining useful lives that extend past 2040, and are covered by existing trading programs, the EPA anticipates more interest in emission trading under combustion turbine emission guidelines. The principles discussed earlier in this notice related to emission trading, under which any such program should ensure emission reductions equivalent to or greater than the emission reductions that would be achieved with unit-by-unit implementation of BSER, would likely be the starting point for the EPA's consideration of emissions trading for an existing combustion turbine rule.

In addition, the EPA is aware of states and utilities that have comprehensive plans to reduce GHG emissions from their turbines to zero, which do not involve either emission trading or installation of CCS. NextERA has a plan to convert 16 GW of natural gas-fired capacity to fire 100 percent hydrogen by 2045.[531] The Illinois "Climate and Equitable Jobs Act", sets dates (ranging from 2030 to 2045) by which individual gas-fired power plants must reduce their emissions to zero. The EPA solicits comment on whether and how to assure that the emission guidelines for combustion turbines provides opportunities for states to develop plans that build upon these state programs.

In addition, the EPA also solicits comment on other key issues relating to state plan requirements that are specific to existing combustion turbines, including timing for state plan submittals, compliance deadlines, and meaningful engagement.

F. Areas that the EPA is Seeking Comment on Related to Existing Turbines

The EPA is seeking comment on four general areas related to developing BSER for existing turbines. First, the EPA is soliciting comment on general assumptions about potential future utilization of turbines. Second, the EPA is soliciting comment on assumptions about sub-categorization and timing of BSER requirements for existing turbines. Third, the EPA is soliciting comment related to specific BSER assumptions for existing turbines. And finally, the EPA is soliciting comment on state plan provisions for existing turbines.

The EPA is seeking comment on a number of issues related to how its consideration of projected future utilization of combined cycles informed its consideration of a potential BSER for existing combustion turbines. First, the EPA is taking comment on its projections of how turbines will operate in the future and the key factors that influence those changes in operation. While EPA modeling shows that there is some increase in emissions from these units in all years following imposition of CAA section 111 standards on existing coal-fired steam generating units

531 *https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf*.

and new stationary combustion turbines, that increase is much smaller in the later years. The EPA believes the magnitude of these trends is significantly impacted by the rate at which new low emitting generation comes on-line, in part incentivized by IRA and BIL. The EPA is taking comment on all aspects of these assumptions including: the speed at which new low-emitting generation will come on-line and the impact that it has on likely capacity factors for combined cycle units (in particular the projection that capacity factors will grow in the 2028/30 timeframe but decrease in later years).

The EPA is also taking comment on how its assumptions about the potential operation of turbines in future years coupled with considerations about the availability of infrastructure should inform its BSER determination. More specifically, the EPA is requesting comment on how to consider the rate of CCS (and potentially hydrogen) infrastructure development in determining a BSER that could potentially impact hundreds of sources.

With regards to the BSER itself, the EPA is taking comment on the applicability of CCS retrofits to existing combustion turbines and its focus on base load turbines (*e.g.*, those with a capacity factor of greater than 50 percent). The EPA is also requesting comment on appropriate parameters to use in the design of a potential subcategory for which CCS would be identified as the BSER. The EPA is also taking comment on the role of low-GHG hydrogen as part of BSER and whether EPA should focus any BSER determination on units with lower capacity factors. The EPA also requests comment on a BSER that could include requirements to co-fire more than 30 percent low-GHG hydrogen and up to 100 percent low-GHG hydrogen. Further, the EPA is soliciting comments on applying such requirements to units that would be covered under the CAA section 111(b) provisions being proposed in this preamble under a potential future CAA section 111(d) rule. Finally, the EPA requests comment on whether heat rate improvements are an appropriate BSER. This includes consideration of whether efficiency improvements make sense as a first step towards firing some amount of low-GHG hydrogen or installing CCS. It also includes consideration of the two types of efficiency subcategories discussed above, one for major turbine upgrades for more inefficient units and one for minor efficiency improvements for more efficient units.

The EPA is also taking comment on state plan requirements for a CAA section 111(d) rule for existing fossil fuel-fired turbines. Specifically, the EPA is taking comment on considerations related to an approach for setting emission standards, implementation of RULOF, and additional flexibilities beyond RULOF. With regards to RULOF, the EPA is specifically seeking comment on the likely remaining useful life of a typical combined cycle unit and simple cycle turbine, how RULOF might factor into a unit whose utilization is projected to change in the future (*e.g.*, how should a state factor in the utilization pattern identified in the EPA's modeling where some units operate at well above 50 percent in the early 2030s, but see a significant increase in capacity factors in the later years.) With regards to flexibility measures, the EPA is seeking comment on the role of trading in implementation of a turbine BSER and how a state could ensure that under a trading program, sources achieved the same level of reductions expected under unit specific implementation of the BSER. Finally, the EPA is taking comment on if and how the EPA should provide flexibility for states who may have already developed, or who may be interested in developing approaches to reduce emissions that are very different than the BSER the EPA might develop and how one could evaluate whether such programs achieve the same or greater emission reductions than unit-by-unit implementation of the BSER.

XIII. Implications for Other EPA Programs

A. Implications for New Source Review (NSR) Program

CAA section 110(a)(2)(C) requires that a state implementation plan (SIP) include a New Source Review (NSR) program that provides for the "regulation of the modification and construction of any stationary source … as necessary to assure that [the NAAQS] are achieved." Within the NSR program, the "major NSR" preconstruction permitting program applies to new construction and modifications of existing sources that emit "regulated NSR pollutants" at or above certain established thresholds. New sources and modifications that emit regulated NSR pollutants under the established thresholds may be subject to "minor NSR" program requirements or may be excluded from NSR requirements altogether. The NSR program for a state or local permitting authority with an approved SIP is implemented through 40 CFR 51.160 to 51.166, while the NSR program applying in areas for which the EPA or a delegated state, local or tribal agency is the permitting authority is implemented through 40 CFR part 49 and 40 CFR 52.21.

NSR applicability is pollutant-specific and, for the major NSR program, the permitting requirements that apply to a source depend on the air quality designation at the location of the source for each of its emitted pollutants at the time the permit is issued. Major NSR permits for sources located in an area that is designated as attainment or unclassifiable for the NAAQS for its pollutants are referred to as Prevention of Significant Deterioration (PSD) permits. In addition, PSD permits can include requirements for specific pollutants for which there are no

NAAQS.[532] Sources subject to PSD must, among other requirements, comply with emission limitations that reflect the Best Available Control Technology (BACT) for "each pollutant subject to regulation" as specified by CAA sections 165(a)(4) and 169(3). Major NSR permits for sources located in nonattainment areas and that emit at or above the specified major NSR threshold for the pollutant for which the area is designated as nonattainment are referred to as Nonattainment NSR (NNSR) permits. Sources subject to NNSR must, among other requirements, meet the Lowest Achievable Emissions Rate (LAER) pursuant to CAA sections 171(3) and 173(a)(2) for any pollutant subject to NNSR. Due to the pollutant-specific applicability of the NSR program, it is conceivable that a source seeking to newly construct or modify may have to obtain multiple types of NSR permits (*i.e.*, NNSR, PSD, or minor NSR) depending on the air quality designation at the location of the source and the types and amounts of pollutants it emits.

A new stationary source is subject to major NSR requirements if its potential to emit (PTE) a regulated NSR pollutant exceeds statutory emission thresholds, upon which the NSR regulations define it as a "major stationary source."[533] For PSD permitting, once a new stationary source is determined to be subject to major NSR for one regulated NSR pollutant (with the

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[532] For the PSD program, "regulated NSR pollutant" includes any pollutant for which a NAAQS has been promulgated ("criteria pollutants") and any other air pollutant that meets the requirements of 40 CFR 52.21(b)(50). Some of these non-criteria pollutants include fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.

[533] For PSD, the statute uses the term "major emitting facility" and defines it as a stationary source that emits, or has a PTE, at least 100 tons per year (TPY) if the source is in one of 28 listed source categories, or at least 250 TPY if the source is not a listed source category. CAA section 169(1). For NNSR, the emissions threshold for a major stationary source is 100 TPY, and lower thresholds apply for certain pollutants based on the severity of the nonattainment classification.

exception of GHG)[534], the source can be subject to major NSR requirements for any other regulated NSR pollutant if the PTE of that pollutant is at least the "significant" emissions rate ("SER"), as defined in 40 CFR 52.21(b)(23). In the case of GHG[535], the EPA has not promulgated a GHG SER but applies a BACT applicability threshold of 75,000 TPY CO_2e.[536]

For an existing source, it can be subject to major NSR requirements if it is a major stationary source and its emissions increase resulting from a modification (*i.e.*, physical change or change in the method of operation) are equal to or greater than the SER for a regulated NSR pollutant, upon which the NSR regulations define it as a "major modification."[537] As with new sources, the one exception to this applicability approach is GHG, which currently applies a BACT applicability threshold in lieu of a SER and can only be subject to major NSR if another pollutant is also subject to major NSR for the modification. Generally, an existing major stationary source triggering major NSR requirements for a regulated NSR pollutant would have both a significant emissions increase from the modification and a significant net emissions increase at the stationary source, and the calculation of the significant emissions increase differs

[534] As a result of the Supreme Court's decision in *UARG v. EPA*, the D.C. Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc. v. EPA*, Nos. 09-1322, 10-073, 10-1092 and 10-1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the PSD and title V regulations under review in that case to the extent that they require a stationary source to obtain a PSD or title V permit solely because the construction of the source, or a modification at the source, emits or has the potential to emit GHGs at or above the applicable major NSR thresholds.

[535] Consistent with the 2009 Endangerment Findings, the PSD program treats GHG as a single air pollutant defined as the aggregate group of six gases: CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6. 40 CFR 52.21(b)(49)(i).

[536] See Janet G. McCabe and Cynthia Giles, Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency* (July 24, 2014), *https://www.epa.gov/sites/default/files/2015-12/documents/20140724memo.pdf*.

[537] Per 40 CFR 52.21(b)(1)(i)(c), a minor source that undergoes a physical change that would itself be considered major, is subject to major source requirements.

depending on whether the modification is to an existing emissions unit, or the addition of a new emissions unit, or if it involves multiple types of emission units.[538] An existing major stationary source would trigger PSD permitting requirements for GHGs if it undertakes a modification and: (1) the modification is otherwise subject to PSD for a pollutant other than GHG; and (2) the modification results in a GHG emissions increase and a GHG net emissions increase that is equal to or greater than 75,000 TPY CO_2e and greater than zero on a mass basis.

Since GHG is not a criteria pollutant, it is regulated under the CAA's PSD program, but not under the NNSR or minor NSR programs. For new sources and modifications that are subject to PSD, the permitting authority must establish emission limitations based on BACT for each pollutant that is subject to PSD at the major stationary source or at each emissions unit involved in the major modification. BACT is assessed on a case-by-case basis, and the permitting authority, in its analysis of BACT for each pollutant, evaluates the emission reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic, and other costs associated with each technology or technique. The CAA also specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS. Permitting authorities may determine BACT by applying the EPA's five-step "top down" approach.[539] The ultimate determination of BACT is made by the permitting authority after a public notice and comment period of at least 30-days on the draft permit and supporting information.[540]

[538] 40 CFR 52.21(a)(2)(iv); 40 CFR 52.21(b)(2)(i); 40 CFR 52.21(b)(3).
[539] *See* U.S. EPA, NSR Workshop Manual (Draft October 1990), *https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf*; U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011), *https://www.epa.gov/sites/default/files/2015-07/documents/ghgguid.pdf*.
[540] 40 CFR 124.10.

1. NSR Implications of a CAA Section 111(b) Standard

As noted above, BACT cannot be set at a level that is less stringent than the standard of performance established by an applicable NSPS,[541] and the EPA refers to this minimum control level as the "BACT floor." While a proposed NSPS does not establish the BACT floor for affected facilities seeking a PSD permit, once an NSPS is promulgated, it then serves as the BACT floor for any new major stationary source or major modification that meets the applicability of the NSPS and commences construction after the date of the proposed NSPS in the *Federal Register*.[542] In the context of combustion turbines that would be subject to this NSPS at 40 CFR part 60, subpart TTTTa, for any new major stationary source or major modification that commences construction or reconstruction of a stationary combustion turbine EGU after the date of publication of this proposed NSPS, the PSD permit should reflect a BACT determination that is at least as stringent as the promulgated NSPS for each of the source's affected EGUs.

However, the fact that a minimum control requirement is established by an applicable NSPS does not mean that a permitting authority cannot select a more stringent control level for the PSD permit or consider technologies for BACT beyond those that were considered in developing the NSPS. As explained above, BACT is a case-by-case review that considers a number of factors, and the review should reflect advances in control technology, reductions in the costs or other impacts of using particular control strategies, or other relevant information that may have become available after development of an applicable NSPS.

[541] *See* 42 U.S.C. § 7479(3) ("In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to [CAA Section 111 or 112].").
[542] U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), p. 25.

2. NSR Implications of a CAA Section 111(d) Standard

With respect to the proposed action for emission guidelines, should it be promulgated, states will be called upon to develop a plan that establish standards of performance for each affected EGU that meets the requirements in the emission guidelines. In doing so, a state agency may develop a plan that results in an affected source undertaking a physical or operational change. Under the NSR program, undertaking a physical or operational change may require the source to obtain a preconstruction permit for the proposed change, with the type of NSR permit (*i.e.*, NNSR, PSD, or minor NSR) depending on the amount of the emissions increase resulting from the change and the air quality designation at the location of the source for its emitted pollutants. More specifically, any time an existing source adds equipment or otherwise makes physical or operational changes to its facility, regardless of whether it has done so to comply with a national or state level requirement, the source may be required to obtain a NSR permit prior to making the changes unless the permitting authority determines that the action is exempt from permitting.[543]

Thus, there are circumstances in which an affected source that is implementing a BSER requirement from a state plan is required to obtain a major NSR permit for one or more of its pollutants. One scenario in which this could occur is if an affected source experiences greater unit availability and reliability as a result of its BSER requirement (perhaps from implementing an efficiency based BSER) that, in turn, lowers the operating costs of its EGU. Since EGUs that operate at lower costs are generally preferred in the dispatch by the system operator over units that have higher operational costs, the BSER implementation could result in improving the

[543] The EPA sought to exempt environmentally beneficially pollution control projects from NSR requirements in a 2002 rule that codified longstanding EPA policy, but this rule was struck down in court. *New York* v. *EPA,* 413 F.3d 3, 40–42 (D.C. Cir. 2005) (*New York I*).

source's relative economics that would, in turn, increase its utilization of its EGU(s). With an increase in utilization resulting from the source implementing the BSER, the annual emissions from the EGU could increase, and if the emissions increase equals or exceeds the relevant SER for one or more of its pollutants, the source may be required to obtain a major NSR permit for the modification.

However, while it may be possible for an affected source to trigger major NSR requirements from actions it takes to implement a BSER requirement, we expect this situation to not occur often. As previously discussed in this preamble, states will have considerable flexibility in adopting varied compliance measures as they develop their plans to meet the standards of performance of the emission guidelines. One of these flexibilities is the ability for states to establish the standards of performance in their plans in such a way so that their affected sources, in complying with those standards, in fact would not have emission increases that trigger major NSR requirements. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the standards of performance, their emissions would not increase in a way that trigger major NSR requirements. For example, a state could, as part of its state plan, develop conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger NSR (effectively establishing a synthetic minor limitation).[544]

[544] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. See, *e.g.*, CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or title V permitting programs. See, *e.g.*, 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of "potential to emit").

B. Implications for Title V Program

Title V is implemented through 40 CFR parts 70 and 71. Part 70 defines the minimum requirements for state, local and tribal (state) agencies to develop, implement and enforce a title V operating permit program; these programs are developed by the state and the state submits a program to the EPA for a review of consistency with part 70. There are about 117 approved part 70 programs in effect, with about 14,000 part 70 permits currently in effect. (See Appendix A of 40 CFR part 70 for the approval status of each state program.) Part 71 is a Federal permit program run by the EPA, primarily where there is no part 70 program in effect (*e.g.*, in Indian country, the Federal Outer Continental Shelf, and for offshore Liquified Natural Gas terminals).[545] There are about 100 part 71 permits currently in effect (most are in Indian country).

The title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from these rules that are imposed on EGUs or other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source's title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of three years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18 months after promulgation of the applicable

[545] In some circumstances, the EPA may delegate authority for part 71 permitting to another permitting agency, such as a tribal agency or a state. The EPA has entered into delegation agreements for certain part 71 permitting activities with at least one tribal agency. There are currently no states that do not have an approved part 70 program; thus, there is no need for the EPA to delegate part 71 delegated authority to any state at this time.

requirement. If the permit has a remaining life of less than three years, the newly applicable requirement must be incorporated at permit renewal.

If a state needs to include provisions related to the state plan in a source's title V permit before submitting the plan to the EPA, these limits should be labeled as "state-only" or "not federally enforceable" until the EPA has approved the state plan. The EPA solicits comment on whether, and under what circumstances, states might use this mechanism.

C. EPA Partnership Programs

For over thirty years, EPA partnership programs have worked alongside the Agency's power sector air regulatory programs. The EPA partnerships do not play a role under any regulations, including the proposed standards. Through non-regulatory efforts, partnerships can help ease the way toward meeting public and private sector air quality and climate goals. These partnership programs seek out and overcome market barriers, support policy implementation at the state, tribal, and local level, and channel marketplace ingenuity toward measurable climate action and greenhouse gas reductions. These efforts can contribute to technology adoption and subnational policy that can lower emissions and reduce compliance costs. Partnership programs support private and sub-national government action with unbiased information including specifications for efficient appliances and equipment, methodologies for measurement, and standardized platforms and templates for program implementation. These efforts are transparent, rigorous, and agreeable to all stakeholders.

For example, ENERGY STAR plays a critical unifying role to guide hundreds of utility energy efficiency programs. ENERGY STAR enables utilities to leverage a common national program platform, avoiding the need to produce individual specifications and resources for each utility energy efficiency program across the nation, which could fragment the market and stall innovation and implementation. Similarly, the EPA's partnership programs provide a suite of off-the-shelf policy tools and guidance that states, cities, and tribes can use to cost-effectively develop and implement policies that are based on widely adopted tools and approaches.

Partnerships relevant to the power sector drive private-sector investment in energy efficiency, renewable energy, and related technologies that produce public benefits. Programs that potentially complement EGU new source performance standards for greenhouse gas emissions are:

- ENERGY STAR, which provides simple, credible, and unbiased information that consumers and businesses rely on to make well-informed decisions on energy efficient measures. ENERGY STAR programs focus on residential and commercial products, commercial buildings and multifamily housing, industrial plants, and new homes.
- EPA's Green Power Partnership, which drives voluntary participation in the green power market. The program provides information, technical assistance, and recognition to companies that use green power. In return, the companies commit to using green power for all, or a portion, of their annual electricity consumption.
- The State and Local Climate and Energy Program, which offers free tools, data, and technical expertise to help state, local, and tribal governments achieve their environmental, energy, equity, and economic objectives. These freely available tools help stakeholders overcome limited access to proprietary tools and analysis.
- Additional EPA resources are also provided to inform organizations' emission reduction measures, including guidance and tools to help measure and manage organizational GHG inventories and targets and impartial tools, policy information, and other resources to help promote environmentally beneficial CHP.

The IRA provides significant funding for Federal, state, and local voluntary policies and programs affecting electricity generation and use and greatly expands incentives for GHG emission reductions in the power sector and electricity end-use sectors. The EPA's partnership programs are well positioned to leverage these new policies to enable significant additional voluntary action, including upgrading homes, buildings, and schools for energy efficiency; achieving a carbon-free power sector; and accelerating low-carbon manufacturing.

XIV. Impacts of Proposed Actions

In accordance with EO 12866 and 13563, the guidelines of OMB Circular A-4 and the EPA's Guidelines for Preparing Economic Analyses, the EPA prepared a RIA for these proposed actions. This RIA presents the expected economic consequences of the EPA's proposed rules, including analysis of the benefits and costs associated with the projected emission reductions for three illustrative scenarios. The first scenario represents the proposed CAA 111(b) and 111(d) proposals in combination. The second and third scenarios represent different stringencies of the combined policies. All three illustrative scenarios are compared against a single baseline. For detailed descriptions of the three illustrative scenarios and the baseline, see Section 1 of the RIA, which is titled "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule."

The three scenarios detailed in the RIA, including the proposal scenario, are illustrative in nature and do not represent the plans that states may ultimately pursue. As there are considerable flexibilities afforded to states in developing their state plans, the EPA does not have sufficient information to assess specific compliance measures on a unit-by-unit basis. Nonetheless, the EPA believes that such illustrative analysis can provide important insights.

In the RIA, the EPA evaluates the potential impacts of the three illustrative scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2024–2042 from the perspective of 2024, using both a three percent and seven percent discount rate. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with the Agency's historic practice. These specific snapshot years are 2028, 2030, 2035, and 2040. In addition to the core benefit-cost analysis, the RIA also includes analyses of anticipated economic and energy impacts, environmental justice impacts, and employment impacts.

The analysis presented in this preamble section summarizes key results of the illustrative policy scenario. For detailed benefit-cost results for the three illustrative scenarios and results of the variety of impact analysis just mentioned, please see the RIA, which is available in the docket for this action.

A. Air Quality Impacts

Total cumulative power sector CO_2 emissions between 2028 and 2042 are projected to be 617 million metric tonnes lower under the illustrative proposal scenario than under the baseline. Table 5 shows projected aggregate annual electricity sector emission changes for the illustrative proposal scenario, relative to the baseline.

Table 5—Projected Electricity Sector Emission Impacts for the Illustrative Proposal Scenario, Relative to the Baseline

	CO_2 (million metric tonnes)	Annual NO_X (thousand short tons)	Ozone Season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)
2028	-10	-7	-3	-12	-1
2030	-89	-64	-22	-107	-6

2035	-37	-21	-7	-41	-1
2040	-24	-13	-4	-30	-1

The emissions changes in these tables do not account for changes in HAP that may occur as a result of this action.

B. Compliance Cost Impacts

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the baseline and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping. In simple terms, these costs are an estimate of the increased power industry expenditures required to comply with the proposed action.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative proposal scenario is designed to reflect, to the extent possible, the scope and nature of the proposed guidelines. However, there is uncertainty with regards to the precise measures that states will adopt to meet the requirements because there are flexibilities afforded to the states in developing their state plans.

We estimate the present value (PV) of the projected compliance costs over the 2024–2042 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. The EAV represents a flow of constant annual values that, had they occurred annually, would yield a sum equivalent to the PV. All dollars are in 2019 dollars. Consistent with Executive Order 12866 guidance, we estimate the PV and EAV using 3 and 7 percent discount rates. The PV of the compliance costs, discounted at the 3-percent rate, is estimated to be about $14 billion, with an EAV of about $0.95 billion. At the 7-percent discount rate, the PV of the compliance costs is estimated to be about $10 billion, with an EAV of about $0.98 billion.

Section 3 of the RIA presents a detailed discussion of the compliance cost projections for the proposed requirements, as well as projections of compliance costs for less and more stringent regulatory options. For a detailed description of these compliance cost projections, please see Section 3 of the RIA.

C. Economic and Energy Impacts

These proposed actions have economic and energy market implications. The energy impact estimates presented here reflect the EPA's illustrative analysis of the proposed rules. States are afforded flexibility to implement the proposed rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Table 6 presents a variety of energy market impact estimates for 2028, 2030, 2035, and 2040 for the illustrative proposal scenario, relative to the baseline.

Table 6—Summary of Certain Energy Market Impacts for the Illustrative Proposal Scenario, Relative to the Baseline
[Percent change]

	2028 (%)	**2030 (%)**	**2035 (%)**	**2040 (%)**
Average price of coal delivered to power sector	-1%	0%	2%	2%
Coal production for power sector use	-2%	-40%	-23%	-15%
Price of natural gas delivered to power sector	0%	9%	-2%	-3%
Price of average Henry Hub (spot)	0%	10%	-2%	-2%
Natural gas use for electricity generation	0%	8%	-1%	-2%

These and other energy market impacts are discussed more extensively in Section 3 of the RIA.

More broadly, changes in production in a directly regulated sector may have effects on other markets when output from that sector – for this rule electricity – is used as an input in the production of other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices. Economy-wide models—and, more specifically, computable general equilibrium (CGE) models—are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy.

In 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory analysis. In its final report, the SAB recommended that the EPA begin to integrate CGE modeling into applicable regulatory analysis to offer a more comprehensive assessment of the effects of air regulations.[546] In response to the SAB's recommendations, the EPA developed a new CGE model called SAGE designed for use in regulatory analysis. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020.[547] The EPA used SAGE to evaluate potential economy-wide impacts of these proposed rules, and the results are contained in an appendix of the RIA. The EPA solicits comment on the SAGE analysis presented in the RIA appendix.

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially

[546] U.S. EPA. 2017. SAB Advice on the Use of Economy-Wide Models in Evaluating the Social Costs, Benefits, and Economic Impacts of Air Regulations. EPA-SAB-17-012.
[547] U.S. EPA. 2020. Technical Review of EPA's Computable General Equilibrium Model, SAGE. EPA-SAB-20-010.

affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Employment impacts of these proposed actions are discussed more extensively in Section 5 of the RIA.

D. Benefits

Pursuant to EO 12866, the RIA for these actions analyzes the benefits associated with the projected emission reductions under the proposals to inform the EPA and the public about these projected impacts. These proposed rules are projected to reduce emissions of CO_2, SO_2, NO_X, and $PM_{2.5}$ nationwide. The potential climate, health, welfare, and water quality impacts of these emission reductions are discussed in detail in the RIA. In the RIA, the EPA presents the projected monetized climate benefits due to reductions in CO_2 emissions and the monetized health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions, based on the emissions estimates in illustrative scenarios described previously. We monetize benefits of the proposed standards and evaluate other costs in part to enable a comparison of costs and benefits pursuant to EO 12866, but we recognize there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified or monetized.

We estimate the climate benefits from these proposed rules using estimates of the social cost of greenhouse gases (SC-GHG), specifically the SC-CO_2. The SC-CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CO_2 includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CO_2, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations naturally restrain the ability of SC-CO_2 estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement. The EPA and other Federal agencies began regularly incorporating SC-GHG estimates in their benefit-cost analyses conducted under EO 12866 since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in a rulemaking process.

We estimate the global social benefits of CO_2 emission reductions expected from the proposed rule using the SC-GHG estimates presented in the February 2021 TSD: *Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990*. These SC-GHG estimates are interim values developed under EO 13990 for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available climate science and economics. We have evaluated the SC-GHG estimates in the TSD and have determined that these estimates are appropriate for use in estimating the global social benefits of CO_2 emission reductions expected from this proposed rule. After considering the TSD, and the issues and studies discussed therein, the EPA finds that these estimates, while likely an underestimate, are the best currently available SC-GHG estimates. These SC-GHG estimates were developed over many years using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. As discussed in Section 4 of the RIA, these interim SC-CO_2 estimates have a number of limitations, including that the models used to produce them do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate-change literature and that several modeling input assumptions are outdated. As discussed in the February 2021 TSD, the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) finds that, taken together, the limitations suggest that these SC-CO_2 estimates likely underestimate the damages from CO_2 emissions. The IWG is currently working on a comprehensive update of the SC-GHG estimates (under EO 13990) taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 TSD and other input from experts and diverse stakeholder groups. The EPA is participating in the IWG's work. In addition, while that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. Most recently, the EPA has developed a draft updated SC-GHG methodology within a sensitivity analysis in the regulatory impact analysis of the EPA's November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process. See Section 4 of the RIA for more discussion of this effort.

In addition to CO_2, these proposed rules are expected to reduce emissions of NO_X and SO_2 and direct $PM_{2.5}$ nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. These proposed rules are also expected to reduce ozone season NO_X emissions nationally. In the presence of sunlight, NO_X and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. The RIA estimates the health benefits of changes in $PM_{2.5}$ and ozone concentrations. The health effect endpoints, effect estimates, benefit unit-values, and how they were selected, are described in the TSD titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*, which is referenced in the RIA for these actions. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in Section 4 of the RIA.

The following PV and EAV estimates reflect projected benefits over the 2024–2042 period, discounted to 2024 in 2019 dollars. We monetize benefits of the proposed standards and evaluate other costs in part to enable a comparison of costs and benefits pursuant to EO 12866, but we recognize there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified. The projected PV of monetized climate benefits is about $30 billion, with an EAV of about $2.1 billion using the SC-CO_2 discounted at 3 percent. The projected PV of monetized health benefits is about $77 billion, with an EAV of about $5.3 billion discounted at 3 percent. Combining the projected monetized climate and health benefits yields a total PV estimate of about $110 billion and EAV estimate of $7.5 billion.

At a 7 percent discount rate, this proposed rule is expected to generate projected PV of monetized health benefits of about $50 billion, with an EAV of about $4.8 billion discounted at 7 percent. Climate benefits remain discounted at 3 percent in this benefits analysis. Thus, this proposed rule would generate a PV of total monetized benefits of $80 billion, with an EAV of $6.9 billion discounted at a 7 percent rate.

The results presented in this section provide an incomplete overview of the effects of the proposals. The monetized benefits estimates do not include important climate benefits that were not monetized in the RIA. In addition, important health, welfare, and water quality benefits anticipated under these proposed rules are not quantified. We anticipate that taking non-monetized effects into account would show the proposals to be more beneficial than the tables in this section reflect. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in section 4 of the RIA.

E. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with the EPA's commitment to integrating environmental justice (EJ) in the Agency's actions, and following the directives set forth in multiple Executive Orders, the Agency has analyzed the impacts of these proposed rules on communities with potential environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. While these proposed rules are targeted at reducing CO_2, a global pollutant, the EPA evaluates, to the extent practicable, whether proposed GHG reductions are accompanied by changes in other health-harming pollutants that may place further burdens on these communities.

Executive Order 12898 is discussed in Section XV.J of this preamble and analytical results are available in section 6 of the RIA.

1. Introduction

Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples. Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through federal government actions. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies."[548]". In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

2. Analytical Considerations

EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, and the EPA's EJ Technical Guidance states that "[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3. For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?"

[548] Plan EJ 2014. Washington, DC: U.S. EPA, Office of Environmental Justice at page 3. Retrieved from https://www.epa.gov/environmentaljustice/plan-ej-2014

To address these questions, the EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures and impacts. For the rules, the EPA quantitatively evaluates 1) the proximity of existing affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by these rules but not modeled here (RIA section 6.4) the distribution of ozone and $PM_{2.5}$ concentrations in the baseline and changes due to the proposed rulemakings across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation (RIA section 6.5). The EPA also qualitatively discusses potential EJ climate impacts (RIA section 6.3). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors emitted from sources affected by the regulatory actions for certain population groups of concern. The baseline demographic proximity analyses examined the demographics of populations living within 5 km and 10 km of the following three sets of sources: 1) all 140 coal plants with units potentially subject to the proposed rules, 2) three coal plants retiring by January 1, 2032 with units potentially subject to the proposed rules, and 3) 19 coal plants retiring between January 1, 2032 to January 1, 2040 with units potentially subject to the proposed rules. The proximity analysis of the full population of potentially affected units greater than 25 MW indicated that the demographic percentages of the population within 10 km and 50 km of the facilities are relatively similar to the national averages. The proximity analysis of the 19 units that will retire from 1/1/32 to 1/1/40 (a subset of the total 140 units) found that the percent of the population within 10 km that is African

American is higher than the national average. The proximity analysis for the 3 units that will retire by 1/1/32 (a subset of the total 140 units) found that for both the 10 km and 50 km populations the percent of the population that is Native American for one facility is significantly above the national average, the percent of the population that is Hispanic/Latino for another facility is significantly above the national average, and all three facilities were well above the national average for both the percent below the poverty level and the percent below two times the poverty level.

Because the pollution impacts that are the focus of these rules may occur downwind from affected facilities, ozone and $PM_{2.5}$ exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of these rulemakings. The baseline $PM_{2.5}$ and ozone exposure analyses respond to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory actions (RIA section 6.5). Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, and those less educated may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group, and American Indian populations and children may also experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory actions for population groups of concern in the baseline (question 1).

Finally, the EPA evaluates how post-policy regulatory alternatives of these proposed rulemakings are expected to differentially impact demographic populations, informing questions

2 and 3 from EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. We infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration. This is due to the small magnitude of the concentration changes associated with these rulemakings across population demographic groups, relative to the magnitude of the baseline disparities (question 2). This EJ assessment also suggests that these actions are unlikely to mitigate or exacerbate $PM_{2.5}$ exposures disparities across populations of EJ concern analyzed. Regarding ozone exposures, while most policy options and future years analyzed will not likely mitigate or exacerbate ozone exposure disparities for the population groups evaluated, ozone exposure disparities may be exacerbated for some population groups analyzed in 2030 under all regulatory options. However, the extent to which disparities may be exacerbated is likely modest, due to the small magnitude of the ozone concentration changes. (question 3).

3. Outreach and Engagement

In outreach with potentially vulnerable communities, residents have voiced two primary concerns. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS and hydrogen, they may continue to face disproportionate burden.

With regards to CCS, the EPA is proposing that CCS is a component of the BSER for both new base load stationary combustion turbine EGUs and existing coal-fired steam generating units that intend to operate after 2040. We are aware of various concerns that potentially vulnerable communities have raised with regards to the use of CCS.

One concern is that adding CCS to EGUs can extend the life of an existing coal-fired steam generating unit, subjecting local residents who have already been negatively impacted by the operation of the coal-fired steam generating unit to additional harmful pollution. Recognizing the important stake that local residents have in this issue, the EPA is proposing that if a state intends to have an EGU retrofitted with CCS as its BSER, the state should go through an enhanced public engagement process. This is discussed more in section XI.F.1.b of the preamble. There are several important factors to consider when evaluating the emission impact of an upgraded EGU. First, CCS is the most effective add-on pollution control available for mitigation of GHG emissions from affected sources. Second, most CCS technologies work much more effectively when emitting the lowest levels of SO_2 as possible, therefore it is likely that as part of a CCS installation, companies will improve their EGUs' SO_2 control. Third, it is likely that a CCS retrofit will trigger preconstruction permitting requirements under the major NSR program because there is the potential for an emission increase of one or more pollutants due to the increased energy needed for CO_2 capture. Major NSR permits provide for the public to comment on the draft permit, which is another avenue for affected residents to have input in the decision of whether to install CCS.

Communities have also expressed concerns about CO_2 pipeline safety and geologic sequestration. As discussed in section VII.F.3.b.iii of the preamble, CO_2 pipeline safety is regulated by PHMSA. These regulations protect against environmental release during transport and PHMSA is developing new measures to further strengthen its safety oversight of CO_2 pipelines. Geologic sequestration of CO_2 is regulated by the EPA through the UIC Program and the GHGRP, which work in combination to ensure security and transparency.

The final concern is about the lack of opportunity to voice opinions about projects like this that affect their communities. As noted above, the major NSR permitting program already provides an opportunity for public input on a draft permit, in which the public could raise concerns specific to the pollution impact of a proposed CCS project at a new or existing source, and the EPA is proposing further community engagement requirements related to state plans under CAA section 111(d). States should have a plan that specifically ensures that community members have an opportunity to share their input if they reside near a coal-fired steam generating unit that plans to install CCS to meet the requirements of these proposed rules.

With regards to the decision to construct a new combustion turbine, most of the safeguards outlined above apply. The only exception is that the community engagement would be done as part of the major NSR permitting provisions. The major NSR provisions would likely also apply to most combustion turbines that co-fire with hydrogen, although there may be cases in which major NSR would not be triggered, specifically: (1) if the new combustion turbine is proposed on the site of an existing facility and the existing facility reduces its pollution more than the combustion turbine would increase it (*e.g.*, if the combustion turbine replaces an existing coal-fired EGU and the facility has emission reduction credits from the shutdown unit), or (2) if the new combustion turbine's emissions are low enough to not trigger major NSR requirements.

The EPA further notes that hydrogen production presents a unique set of potential issues for vulnerable communities. For example, during the February 27th National Tribal Energy Roundtable Webinar, one of the primary concerns articulated was the potential for fossil-derived hydrogen to essentially extend the life of petrochemical industries already creating localized pollution loading. Perceived community risks with hydrogen related to storage and transportation include its combustibility and propensity to leak due to extremely low molecular weight. Water scarcity could be exacerbated in some areas by the freshwater demands of electrolytic hydrogen production which is particularly vexing for vulnerable communities.

F. Grid Reliability Considerations

The requirements for sources and states set forth in these proposed actions were developed cognizant of concerns about an electric grid under transition, and related reliability considerations. As previously stated, a variety of important influences have led to notable changes in the generation mix and expectations of how the power sector will evolve. These trends have generally put existing fossil fuel-fired generators under greater economic pressure and will continue to do so even absent any EPA action pursuant to CAA section 111, and that is manifest in various economic projections and modeling of the electric power system. Recent legislation, including the IIJA, the IRA, and state policies have amplified these trends, with continued change expected for the existing fleet of EGUs. Moreover, many regions of the country have experienced a significant increase in the frequency and severity of extreme weather events—events that are notably projected to worsen if GHG emissions are not adequately controlled. These events have impacted energy infrastructure and both the demand for and supply of electricity. A wide range of stakeholders including power generators, grid operators and state and federal regulators are actively engaged in ensuring the reliability of the electric power system is maintained and enhanced in the face of these changes.

As explained in this preamble, these proposed actions take account of the rapidly evolving power sector and extensive input received from power companies and other stakeholders on the future of these regulated sources, while ensuring that new natural gas-fired combustion turbines and existing steam EGUs achieve significant and cost-effective reductions in GHG emissions through the application of adequately demonstrated control technologies, Preserving the ability of power companies and grid operators to maintain system reliability has been a paramount consideration in the development of these proposed actions. Accordingly, these proposed rules include significant design elements that are intended to allow the power sector continued resource and operational flexibility, and to facilitate long-term planning during this dynamic period. Among other things, these elements include subcategories of new natural gas-fired combustion turbines that allow for the stringency of GHG emission standards to vary by capacity factor; subcategories for existing steam EGUs that are based on operating horizons and fuel, and that accommodate the plans of many power companies to transition away from these sources; compliance deadlines for both new and existing EGUs that provide ample lead time to plan; and proposed state plan flexibilities – As such, these proposed rules provide the flexibility needed to avoid reliability concerns while still securing the pollution reductions required.

To support these proposed actions, the EPA has conducted an analysis of resource adequacy based upon power sector modeling and projections that can be found in the RIA. Any potential impact of these proposed actions is dependent upon a myriad of decisions and compliance choices source owners and operators may pursue. It is important to recognize that the proposed rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric reliability. The results presented in the *Resource Adequacy and Reliability Assessment* TSD, which is available in the docket, show that the projected impacts of the proposed rules on power system operations, under conditions preserving resource adequacy, are modest and manageable. For the specific scenarios analyzed in the RIA, the implementation of the proposed rules can be achieved without undermining resources adequacy or reliability even as shifts in existing and new capacity occur. Retirements are offset by additions, along with reserve transfers where/when needed, which demonstrates that ample compliance pathways exist for sources while preserving reliability.

The EPA routinely consults with the DOE and FERC on electric reliability, and intends to continue to do so as it develops and implements a final rule. This ongoing engagement will be strengthened with routine and comprehensive communication between the agencies under the DOE-EPA *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* signed on March 8, 2023.[549] The memorandum will provide greater interagency engagement on electric reliability issues at a time of significant dynamism in the power sector, allowing the EPA and the DOE to use their considerable expertise in various aspects of grid reliability to support the ability of Federal and state regulators, grid operators, regional reliability entities, and power companies to continue to deliver a high standard of reliable electric service. As the power sector continues to change and as the agencies carry out their respective authorities, the agencies intend to continue to engage and collectively monitor, share information, and consult on policy and program decisions to assure the continued reliability of the bulk power system.

In addition, EPA observes that power companies, grid operators, and state public utility commissions have well-established procedures in place to preserve electric reliability in response to changes in the generating portfolio, and expects that those procedures will continue to be effective in addressing compliance decisions that power companies may make over the extended time period for implementation of these proposed rules. In response to any regulatory

[549] *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 8, 2023), available at *https://www.epa.gov/power-sector/electric-reliability-mou*.

requirement, affected sources will have to take some type of action to reduce emissions, which will generally have costs. Some EGU owners may conclude that, all else being equal, retiring a particular EGU is likely to be the more economic option from the perspective of the unit's customers and/or owners because there are better opportunities for using the capital than investing it in new emissions controls at the unit. Such a retirement decision will require the unit's owner to follow the processes put in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. In some rare instances where the reliability of the system is jeopardized due to extreme weather events or other unforeseen emergencies, authorities can request a temporary reprieve from environmental requirements and constraints (through DOE) in order to meet electric demand and maintain reliability. This proposed action does not interfere with these already available provisions, but rather provides a long-term pathway for sources to develop and implement a proper plan to reduce emissions while maintaining adequate supplies of electricity.

XV. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

These actions are significant under Section 3(f)(1) of Executive Order 12866 regulatory actions that were submitted to the Office of Management and Budget (OMB) for inter-agency review. Any changes made in response to reviewer recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with these actions. This analysis, "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," is available in the docket.

Table 7 presents the estimated present values (PV) and equivalent annualized values (EAV) of the projected climate benefits, health benefits, compliance costs, and net benefits of the proposed rule in 2019 dollars discounted to 2024. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the proposed rules.

The projected climate benefits in table 7 are based on estimates of the social cost of carbon (SC-CO_2) at a 3 percent discount rate and are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. Under EO 12866, the EPA is directed to consider the costs and benefits of its actions. Accordingly, in addition to the projected climate benefits of the proposal from anticipated reductions in CO_2 emissions, the projected monetized health benefits include those related to public health associated with projected reductions in fine particulate matter ($PM_{2.5}$) and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the proposed requirements.

These results present an incomplete overview of the potential effects of the proposals because important categories of benefits—including benefits from reducing HAP emissions — were not monetized and are therefore not reflected in the benefit-cost tables. The EPA anticipates that taking non-monetized effects into account would show the proposals to have a greater net benefit than this table reflects.

Table 7—Projected Monetized Benefits, Compliance Costs, and Net Benefits of the Proposed Rules, 2024 through 2042
[Billions 2019$, Discounted to 2024][a]

		3% Discount Rate	7% Discount Rate
Present Value	Climate Benefits[c]	$30	$30
	Health Benefits[d]	$77	$50
	Compliance Costs	$14	$10
	Net Benefits[e]	**$93**	**$70**
Equivalent Annualized Value[b]	Climate Benefits[c]	$2.1	$2.1
	Health Benefits[d]	$5.3	$4.8
	Compliance Costs	$0.95	$0.98
	Net Benefits[e]	$6.5	$5.9

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.
[b] The annualized present value of costs and benefits are calculated over the 20-year period from 2024 to 2042.
[c] Climate benefits are based on changes (reductions) in CO_2 emissions. Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate and are discounted using a 3 percent discount rate to obtain the PV and EAV estimates in the table. The EPA does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate).. As discussed in Section 4 of the RIA, consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.
[d] The projected monetized health benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent.
[e] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

As shown in table 7, the proposed rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $30 billion, with an EAV of about $2.1 billion using the SC-CO_2 discounted at 3 percent. The proposed rules are also projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $77 billion, with an EAV of about $5.3 billion discounted at 3 percent.

The PV of the projected compliance costs are $14 billion, with an EAV of about $0.95 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $93 billion and EAV of about $6.5 billion at a 3% discount rate. The PV of the projected compliance costs are about $10 billion, with an EAV of $0.98 billion discounted at 7 percent. At a 7 percent discount rate, the proposed rules are expected to generate projected PV of monetized health benefits of about $50 billion, with an EAV of about $4.8 billion. Climate benefits remain discounted at 3 percent in this net benefits analysis. Thus, the proposed rules would generate a PV of monetized benefits of about $80 billion, with an EAV of about $6.9 billion discounted at a 7 percent rate. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $70 billion and an EAV of about $5.9 billion.

As discussed in section XIV of this preamble, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the proposals. The monetized benefits estimates do not include important climate benefits that were not monetized in the RIA. In addition, important health, welfare, and water quality benefits anticipated under these proposed rules are not quantified or monetized. The EPA anticipates that taking non-monetized effects into account would show the proposals to be more net beneficial than the tables in this section reflect.

B. Paperwork Reduction Act (PRA)

1. 40 CFR Part 60, Subpart TTTT

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number [placeholder]. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Respondents/affected entities: [placeholder]

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: [placeholder]

Frequency of response: [placeholder]

Total estimated burden: [placeholder] hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $ [placeholder] (per year), includes $ [placeholder]annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting "Currently under Review—Open for Public Comments" or by using the search function. OMB must receive comments no later than **[INSERT DATE 60 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]**.

2. 40 CFR Part 60, Subpart TTTTa

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number [placeholder]. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Respondents/affected entities: [placeholder]

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: [placeholder]

Frequency of response: [placeholder]

Total estimated burden: [placeholder] hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $ [placeholder] (per year), includes $ [placeholder]annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the

EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting "Currently under Review—Open for Public Comments" or by using the search function. OMB must receive comments no later than **[INSERT DATE 60 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]**.

3. 40 CFR Part 60, Subpart UUUUb

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number [placeholder]. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

This rule imposes specific requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit GHG emissions from existing EGUs. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to be 95,680 hours at a total annual labor cost of

$12.1 million. The annual burden for the Federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 25,659 hours at a total annual labor cost of $991,451. Burden is defined at 5 CFR 1320.3(b).

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 50.

Frequency of response: Once.

Total estimated burden: 95,680 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $12,110,762, includes $36,750 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting "Currently under Review—Open for Public Comments" or by using the search function. OMB must receive comments no later than **[INSERT DATE 60 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]**.

4. 40 CFR Part 60, Subpart UUUUa

This proposed rule does not impose an information collection burden under the PRA.

C. Regulatory Flexibility Act (RFA)

I certify that these actions will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of the NSPS are private companies, investor-owned utilities, cooperatives, municipalities, and sub-divisions, that would seek to build and operate stationary combustion turbines in the future. The Agency has determined that seven small entities may be so impacted, and may experience an impact of 0 percent to 0.9 percent of revenues in 2035. Details of this analysis are presented in section 5.3 of the RIA.

The EPA started the Small Business Advocacy Review (SBAR) panel process prior to determining if the NSPS would have a significant economic impact on a substantial number of small entities under the RFA. The EPA conducted an initial outreach meeting with small entity representatives on December 14, 2022. The EPA sought input from representatives of small entities while developing the proposed NSPS which enabled the EPA to hear directly from these representatives about the regulation of GHG emissions from EGUs. The purpose of the meeting was to provide general background on the NSPS rulemaking, answer questions, and solicit input. Fifteen various small entities that potentially would be affected by the NSPS attended the meeting. The representatives included small entity municipalities, cooperatives, and industry professional organizations. When the EPA determined the NSPS would not have a significant economic impact on a substantial number of small entities under the RFA, the EPA did not proceed with convening the SBAR panel.

Emission guidelines will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources, and it is those state requirements that could potentially impact small entities.

The analysis in the accompanying RIA is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans. *See American Trucking Assoc.* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

The EPA is aware that there is substantial interest in the proposed rules among small entities and invites comments on all aspects of the proposals and their impacts, including potential impacts on small entities.

D. Unfunded Mandates Reform Act of 1995 (UMRA)

The proposed NSPS contain a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for the private sector in any one year. The proposed NSPS do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate. Accordingly, the EPA prepared, under section 202 of UMRA, a written statement of the benefit-cost analysis, which is in Section XIV and in the RIA.

The proposed repeal of the ACE Rule and emission guidelines do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and do not significantly or uniquely affect small governments. The proposed emission guidelines do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop plans to implement the guidelines under CAA section 111(d) for designated EGUs. The burden for states to develop CAA section 111(d) plans in the 24-month period following promulgation of the emission guidelines was estimated and is listed in section XV.B, but this burden is estimated to be below $100 million in any one year. As explained in section XI.F.6, the proposed emission guidelines do not impose specific requirements on tribal governments that have designated EGUs located in their area of Indian country.

The proposed actions are not subject to the requirements of section 203 of UMRA because they contain no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest in these rules among governmental entities, the EPA initiated consultation with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the “Big 10” organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. Subsequent to the September 22, 2022, meeting, the EPA received letters from five organizations. These letters were submitted to the pre-proposal non-rulemaking docket. See Docket ID No. EPA-HQ-OAR-2022-0723-0013, EPA-HQ-OAR-2022-0723-0016, EPA-HQ-OAR-2022-0723-0017, EPA-HQ-OAR-2022-0723-0020, and EPA-HQ-OAR-2022-0723-0021. For summary of the UMRA consultation see the memorandum in the docket titled, *Federalism Pre-Proposal Consultation Summary*.

E. Executive Order 13132: Federalism

The proposed NSPS and the proposed repeal of the ACE Rule do not have federalism implications. These actions will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

The EPA has concluded that the proposed emission guidelines may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay these costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed emission guidelines, as well as time to work with state legislatures as appropriate, and develop a plan submittal.

The EPA consulted with representatives of state and local governments in the process of developing these actions to permit them to have meaningful and timely input into their development. The EPA's consultation regarded planned actions for the NSPS and emission guidelines. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. Subsequent to the September 22, 2022, meeting, the EPA received letters from five organizations. These letters were submitted to the pre-proposal non-rulemaking docket. See Docket ID No. EPA-HQ-OAR-2022-0723-0013, EPA-HQ-OAR-2022-0723-0016, EPA-HQ-OAR-2022-0723-0017, EPA-HQ-OAR-2022-0723-0020, and

EPA-HQ-OAR-2022-0723-0021. For a summary of the Federalism consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary*. A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final emission guidelines, as required by section 6(b) of Executive Order 13132. In the spirit of EO 13132, and consistent with EPA policy to promote communications between state and local governments, the EPA specifically solicits comment on these proposed actions from state and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

These actions do not have tribal implications, as specified in Executive Order 13175. The proposed NSPS would impose requirements on owners and operators of new or reconstructed stationary combustion turbines and emission guidelines would not impose direct requirements on tribal governments. Tribes are not required to develop plans to implement the emission guidelines developed under CAA section 111(d) for designated EGUs. The EPA is aware of six fossil fuel-fired steam generating units located in Indian country but is not aware of any fossil fuel-fired steam generating units owned or operated by tribal entities. The EPA notes that the proposed emission guidelines do not directly impose specific requirements on EGU sources, including those located in Indian country, but before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes. Thus, Executive Order 13175 does not apply to these actions.

Because the EPA is aware of tribal interest in these proposed rules and consistent with the *EPA Policy on Consultation and Coordination with Indian Tribes*, the EPA offered government-to-government consultation with tribes and conducted stakeholder engagement.

The EPA will hold additional meetings with tribal environmental staff to inform them of the content of these proposed rules as well as offer government-to-government consultation with tribes. The EPA specifically solicits additional comment on these proposed rules from tribal officials.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks Populations and Low-Income Populations

These actions are subject to Executive Order 13045 because they are economically significant regulatory actions as defined by Executive Order 12866, and the EPA believes that these rule will reduce emissions of CO_2, ozone and $PM_{2.5}$. The EPA evaluated the health benefits of these emissions reductions and the results of this evaluation are contained in the RIA and are available in the docket. The EPA believes that the $PM_{2.5}$-related, ozone-related, and CO_2-related benefits projected under these proposed rules will improve children's health. Additionally, the $PM_{2.5}$ and ozone EJ exposure analyses in section 6 of the RIA suggests that nationally, children (ages 0-17) will experience at least as great a reduction in $PM_{2.5}$ and ozone exposures as adults (ages 18-64) in 2028, 2030, 2035 and 2040 under all regulatory alternatives of these rulemakings.

H. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

These actions, which are significant regulatory actions under Executive Order 12866, are likely to have a significant adverse effect on the supply, distribution or use of energy. The EPA has prepared a Statement of Energy Effects for these action as follows. The EPA estimates a 0.2 percent increase in retail electricity prices on average, across the contiguous U.S. in 2035, and a 28 percent reduction in coal-fired electricity generation in 2035 as a result of these actions. The

EPA projects that utility power sector delivered natural gas prices will decrease 2.4 percent in 2035. For more information on the estimated energy effects, please refer to the economic impact analysis for this action. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

These proposed actions involve technical standards. Therefore, the EPA conducted searches for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods [placeholder]. No applicable voluntary consensus standards were identified for EPA Methods [placeholder]. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for these rules. [placeholder] VCS were identified as an acceptable alternative to EPA test methods for the purpose of these proposed rules. The search identified [placeholder] VCS that were potentially applicable for these proposed rules in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the March [placeholder], 2023, memorandum titled, *Voluntary Consensus Standard Results for New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*. In this document, the EPA is proposing to include in final rule regulatory text for 40 CFR part 60, subpart TTTT, TTTTa, and UUUUb that includes incorporation by reference. In accordance with requirements of 1 CFR part 51, the EPA is proposing to incorporate the following [placeholder] standards by reference.

- [placeholder]
- [placeholder]

The EPA welcomes comments on this aspect of the proposed rulemakings and, specifically, invites the public to identify potentially applicable VCS and to explain why such standards should be used in these regulations.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or Indigenous peoples) and low-income populations.

For new sources constructed after the date of publication of this proposed action under CAA section 111(b), the EPA believes that it is not practicable to assess whether the human health or environmental conditions that exist prior to this action result in disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples, because the location and number of new sources is unknown.

For existing sources of this proposed action under CAA section 111(d), the EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations, and/or Indigenous peoples. The EPA believes that this proposed action is not likely to change disproportionate and adverse $PM_{2.5}$ exposure impacts on people of color, low-income populations, Indigenous peoples, and/or other potential populations of concern evaluated in the future analytical years. The EPA also believes that this proposed action is not likely to change disproportionate and adverse ozone exposure impacts on people of color, low-income populations, Indigenous peoples, and/or other potential populations of concern evaluated in 2028, 2035, and 2040. However, in the analytical year of 2030, this action is likely to slightly increase existing national level disproportionate and adverse ozone exposure impacts on Asian populations, Hispanic populations, and those linguistically isolated.

The EPA believes that it is not practicable to assess whether the GHG impacts associated with this action are likely to result in a change in disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples. However, the EPA believes that the projected total cumulative power sector reduction of 617 million metric tonnes of CO_2 emissions between 2028 and 2042 will have a beneficial effect on populations at risk of climate change effects/impacts. Research indicates that some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the U.S. See sections VII, X, and XIV of this preamble for further information regarding GHG controls and emission reductions.

Michael S. Regan,

Administrator.

IPM Model – Updates to Cost and Performance for APC Technologies

CO_2 Reduction Retrofit Cost Development Methodology

Final

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Project 13527-002

Eastern Research Group, Inc.

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This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

CO_2 Reduction Retrofit Cost Development Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control, such as project contingency.

Establishment of the Cost Basis

To establish a basis for retrofit of carbon dioxide (CO_2) reduction technologies, cost data were collected from the public domain and Sargent & Lundy's (S&L's) recent experience associated with recent amine-based CO_2 capture processes implemented as retrofits to power facilities. All data sources were combined to provide a representative CO_2 reduction cost basis. Due to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions. While the coal-fired applications utilize a robust amount of data sources, from feasibility and FEED studies, it is only recently that feasibility and FEED studies have been completed for NGCC applications of this technology. As such, cost multipliers are used to compare coal-fired capital cost pricing to NGCC applications.

A cost algorithm for pre-combustion CO_2 reduction using oxy-combustion technology was not developed. This technology is best reserved for new units, rather than for power plant retrofits. In addition, there are too few examples of retrofits to provide a basis for the costs. Therefore, an algorithm cannot be accurately developed and is not included in the CO_2 reduction technology algorithm. For retrofit applications, the oxy-combustion technology will need to be evaluated on a case-by-case basis to justify its cost competitiveness against the almost commercially demonstrated amine-based capture technology.

CO_2 Reduction Retrofit Cost Development Methodology

The least-squares curve fit of the data was defined as a "typical" CO_2 capture retrofit for removal of >90% of the inlet CO_2. The typical CO_2 capture retrofit was based on the following:

- Retrofit Difficulty = 1 (average retrofit difficulty);
- Gross Heat Rate = 10,000 Btu/kWh;
- Type of Coal = PRB;
- Project Execution = Engineer, Procurement, and Construction (EPC) contracts; and
- Typical CO_2 capture rate = 90% removal efficiency.

For CO_2 capture, the technology is expected to be applicable to any unit size and, depending how much flue gas is treated, would scale up based on multiple parallel capture trains. Transportation, storage, and monitoring (TS&M) of the captured CO_2 are not included in the base cost estimates and instead costs can be included as a user input on a $/ton basis.

CO_2 Capture Methodology

Technology Description

The amine-scrubbing process is the most widely studied and used demonstration process for post-combustion CO_2 capture. This process involves passing the flue gas through an absorber column counter-currently with an amine solvent. At low temperatures, the CO_2 is absorbed by the amine solvent and removed from the flue gas. The treated flue gas passes through wash levels prior to exiting the stack. The CO_2-rich solvent leaves the absorber and is heated and regenerated in the stripper column. Once the CO_2 is desorbed from the amine, a concentrated CO_2 stream is dehydrated to remove any moisture and compressed to pipeline quality for transportation and/or sequestration. Steam is typically taken from the unit's existing steam cycle and passed through a reboiler to provide the heat needed to strip the CO_2 from the amine. While certain applications justify the use of new natural gas auxiliary boilers for steam production, this module is based solely on steam extraction, to avoid additional emissions associated with additional fuel combustion.

To limit degradation of the expensive amine solvent, SO_2 and SO_3 emissions must be treated prior to the absorber vessel to lower concentrations of these emissions to less than 2 to 10 ppm. If a unit is not already equipped with flue gas desulfurization (FGD) technology, then it will need to be added. Therefore, capital and operating and maintenance (O&M) costs for a wet FGD (WFGD) which is capable of lowering the SO_2 concentration down to 2-10 ppm should be included as part of the overall CO_2 capture cost. Note that the cost of retrofitting FGD is not included as part of the CO_2 cost algorithm.

CO_2 Reduction Retrofit Cost Development Methodology

Inputs

Several input variables are required to predict future retrofit costs. The gross unit size in MW and carbon content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to the difficulty in construction of the system must be defined. Note that the costs could increase significantly for congested sites or sites with limited adjacent space. One example for the use of a retrofit factor is if a facility needs to minimize additional water consumption. For cases where a hybrid cooling system is required due to limited water availability, a retrofit factor of 1.15 should be used to account for the increase in the capital cost associated with that system.

The gross unit heat rate will factor into the amount of flue gas generated and, ultimately, the size of the absorber, stripper, compressor, and balance of plant costs. Heat rate is an input from the user, with a suggested starting point of 10,000 Btu/kWh for coal-fired boilers, and 6,660 Btu/kWh for natural gas combined cycle (NGCC) facilities.

The CO_2 rate will have the greatest influence on the solvent makeup rate and steam required in the regeneration process. The type of fuel (Bituminous, PRB, Lignite, or Natural Gas) will influence the CO_2 quantity in the flue gas because of the differing carbon compositions typical in these types of fuels.

The evaluation includes a user-selected option for identifying if the unit is equipped with FGD. If the unit fires coal and is not already equipped with FGD technology, costs for installing a WFGD should also be incorporated. The user is required to use the WFGD IPM cost algorithm to generate the capital and O&M costs for the technology.

Any changes from the base assumptions should be incorporated to derive more accurate costs.

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. Note that costs to build a pipeline are not included in this cost algorithm; it is assumed that another entity will be funding the CO_2 pipeline construction. The base module installed costs include the following:

- All equipment,
- Installation,
- Buildings,
- Foundations,
- Electrical, and
- Retrofit difficulty.

CO_2 Reduction Retrofit Cost Development Methodology

These costs can potentially range widely because of the relatively new nature of the process, as well as site-specific details. Capital costs estimated here are expected to encompass a +/- 50% range.
The base modules are as follows:

BMI =	Base capture island cost, including compression
BMBOP =	Base balance of plant costs including piping, ductwork, cooling system, steam integration, foundations, etc.
BM =	BMI + BMBOP

The total base module installed cost (BM) is then increased by the following:

- Engineering and construction management costs at 15% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include the following:

- Owner’s home office costs (owner’s engineering, management, and procurement) are included at 5% of the CECC.
- Allowance for Funds Used During Construction (AFUDC) are included at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

The total project cost is based on a turnkey engineering, procurement, and construction (EPC) contract execution; as such, the total project cost is increased by 15% to account for risk and fees associated with this structure.

Escalation is not included in the estimate because all costs are provided in 2021 dollars and are not representative of recent COVID and inflation related pricing increases. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

CO_2 Reduction Retrofit Cost Development Methodology

Fixed O&M (FOM)

The fixed O&M cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the CO_2 capture installation. The FOM is the sum of the FOMO, FOMM and FOMA.
The following factors and assumptions underlie calculations of the FOM:

- All the FOM costs were tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 22 additional shift operators are required for operating the CO_2 capture facility. The FOMO was based on the number of additional operations staff required as a function of generating capacity.
- The fixed maintenance materials and labor factor is a direct function of the process capital cost at 2.5% of the equivalent equipment and material portion, which is expected to be 60% of the BM.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of the following:

- Solvent makeup rates and unit costs,
- Additional power required and unit power cost,
- Loss of production due to steam consumption from the base plant, and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All the VOM costs were tabulated on a per-megawatt-hour (MWh) basis.
- A VOM related calculations are estimated using different equations for NGCC and coal-fired applications.
- The solvent makeup cost is a function of total CO_2 captured. The capital costs are based on a 90% CO_2 reduction design. An indicative value is included but can be adjusted by the user.
- The steam derate is estimated based on the steam extracted for use in the CO_2 regeneration process. Steam rate is a function of total CO_2 captured.
- The additional power required includes increased fan power to account for the added capture island pressure drop, system pumps, and compressor power. This requirement is a function of total CO_2 captured.
- The makeup water rate is a function of total CO_2 captured.

CO_2 Reduction Retrofit Cost Development Methodology

- The transportation, storage, and monitoring costs are not included. A cost can be added by the user, based on an evaluated cos with respect to the amount of CO_2 captured in ton.

Because of the widely varying consumption of power, steam, water, and solvent associated with the various CO_2 capture technologies, the variable O&M costs are developed as a fixed amount based on averages of S&L in-house project data and design assumptions, calculated separately for coal-fired or NGCC applications. Steam turbine derate is not calculated separately, as the derate is expected to be similar based on total steam extraction, regardless of application.

Input options are provided so the user can adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are as follows:

- Solvent cost in $/ton of CO_2 captured; the cost could vary significantly by process supplier;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1,000 gallons;
- Operating labor rate (including all benefits) in $/hr; and
- Transportation, storage, and monitoring costs in $/ton.

The variables that contribute to the overall VOM are shown below:

VOMS =	Variable O&M costs for solvent
VOMTS =	Variable O&M costs for transportation and storage of capture CO_2
VOMP =	Variable O&M costs for additional auxiliary power and steam consumption (lost revenue)
VOMM =	Variable O&M costs for makeup water

The total VOM is the sum of VOMS, VOMTS, VOMP, and VOMM. Table 1 is a complete capital and O&M cost estimate worksheet.

CO_2 Reduction Retrofit Cost Development Methodology

Table 1. Example 1 (Coal)

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	10000	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		PRB	<--- User Input
CO2 Capture Rate	E	(ton/hr)	674	A*C*1000*0.9*Coal Rate /10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		FGD	<--- User Input
Steam Consumption	G	(lb/hr)	1,590,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	99	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	4894	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	123	0.155 * G / 2000
Net Power Reduction	K	(MW)	222	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/kWh)	0.03	<--- User Input
Makeup Water Cost	N	($/kgal)	1	<--- User Input
Operating Labor Rate	O	($/hr)	60	<--- User Input (Labor cost including all benefits)
Transportation, Storage, & Monitoring (TS&M)	P	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMI ($) = +B24:L34BI	Coal: [883000*(E)] * B ; NGCC: [883000*(E)] * B * 1.45	$ 595,230,000	Base CO2 capture island cost including: Absorbers and stacks, strippers, blowers, reagent tanks, heat exchangers, compressors, etc...
BMBOP ($) =	Coal: [235200*(E)] * B ; NGCC: [235200*(E)] * B * 1.45	$ 158,548,000	Base balance of plant costs including: Cooling system, steam supply, piping, ductwork, foundations, etc...
BM ($) =	BMI + BMC + BMBOP	$ 753,778,000	Total base cost including retrofit factor
BM ($/KW) =		1077	Base cost per kW
Total Project Cost			
A1 = 15% of BM		$ 113,067,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 75,378,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$ 75,378,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 1,017,601,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**1454**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 50,880,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 1,068,481,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**1526**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 106,848,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC + B1		$ 168,667,000	EPC G&A and risk fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 1,175,329,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**1679**	Total project cost per kW

CO_2 Reduction Retrofit Cost Development Methodology

Table 1. Example 1 (Coal) Continued

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	10000	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		PRB	<--- User Input
CO2 Capture Rate	E	(ton/hr)	674	A*C*1000*0.9*Coal Rate /10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		FGD	<--- User Input
Steam Consumption	G	(lb/hr)	1,590,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	99	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	4894	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	123	0.155 * G / 2000
Net Power Reduction	K	(MW)	222	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/kWh)	0.03	<--- User Input
Makeup Water Cost	N	($/kgal)	1	<--- User Input
Operating Labor Rate	O	($/hr)	60	<--- User Input (Labor cost including all benefits)
Transportation, Storage, & Monitoring (TS&M)	P	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = 22*2080*O/(A*1000)	$	3.92	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.6*0.025/(B*A*1000)	$	16.15	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.31	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**20.39**	Total Fixed O&M costs
Variable O&M Cost			
VOMS ($/MWh) = L * E / A	$	3.37	Variable O&M costs for solvent
VOMTS ($/MWh) = P * E / A	$	9.63	Variable O&M costs for transportation, storage, and monitoring
VOMP ($/MWh) = K * 1000 * M / A	$	9.51	Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue
VOMM ($/MWh) =I * 60 / 1000 * N / A	$	0.42	Variable O&M costs for makeup water
VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM	**$**	**22.93**	Total Variable O&M costs

Annual Capacity Factor =	0.85	
Annual MWhs =	5,212,200	
Annual Heat Input MMBtu =	52,122,000	
Annual Ton CO2 Created =	5,577,054	
Annual Ton CO2 Removed =	5,019,349	at removal efficiency = 90%
Annual Ton CO2 Emission =	557,705	
Annual Avg CO2 Emission Rate, lb/MWh =	214	based on original gross unit load [A]

Annual Capital Recovery Factor =	0.082	CO2 Capture *from DOE 2019 BBS 12B*
Annual Capital Cost (Including AFUDC), $ =		96,377,000
Annual FOM Cost, $ =		14,270,000
Annual VOM Cost, $ =		119,535,000
Total Annual CO2 Capture Cost, $ =		230,182,000
Capital Cost, $/MWh =		18.49
FOM Cost, $/MWh =		2.74
VOM Cost, $/MWh =		22.93
Total CO2 Capture Cost, $/MWh =		44.16
Capital Cost, $/ton =		19
FOM Cost, $/ton =		3
VOM Cost, $/ton =		24
Total CO2 Capture Cost, $/ton =		46

CO_2 Reduction Retrofit Cost Development Methodology

Table 2. Example 1 (NGCC)

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	6660	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		NGCC	<--- User Input
CO2 Capture Rate	E	(ton/hr)	245	A*C*1000*0.9*Coal Rate /10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		None	<--- User Input
Steam Consumption	G	(lb/hr)	652,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	51	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	2388	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	51	0.155 * G / 2000
Net Power Reduction	K	(MW)	102	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/kWh)	0.03	<--- User Input
Makeup Water Cost	N	($/kgal)	1	<--- User Input
Operating Labor Rate	O	($/hr)	60	<--- User Input (Labor cost including all benefits)
Transportation, Storage, & Monitoring (TS&M)	P	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMI ($) = +B24:L34BI	Coal: [883000*(E)] * B ; NGCC: [883000*(E)] * B * 1.45	$ 314,267,000	Base CO2 capture island cost including: Absorbers and stacks, strippers, blowers, reagent tanks, heat exchangers, compressors, etc…
BMBOP ($) =	Coal: [235200*(E)] * B ; NGCC: [235200*(E)] * B * 1.45	$ 83,710,000	Base balance of plant costs including: Cooling system, steam supply, piping, ductwork, foundations, etc…
BM ($) =	BMI + BMC + BMBOP	$ 397,977,000	Total base cost including retrofit factor
BM ($/KW) =		569	Base cost per kW
Total Project Cost			
A1 = 15% of BM		$ 59,697,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 39,798,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 39,798,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 537,270,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**768**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 26,864,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 564,134,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**806**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 56,413,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC + B1		$ 89,052,000	EPC G&A and risk fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 620,547,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**886**	Total project cost per kW

CO_2 Reduction Retrofit Cost Development Methodology

Table 2. Example 2 (NGCC) Continued

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	6660	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		NGCC	<--- User Input
CO2 Capture Rate	E	(ton/hr)	245	A*C*1000*0.9*Coal Rate /10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		None	<--- User Input
Steam Consumption	G	(lb/hr)	652,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	51	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	2388	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	51	0.155 * G / 2000
Net Power Reduction	K	(MW)	102	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/kWh)	0.03	<--- User Input
Makeup Water Cost	N	($/kgal)	1	<--- User Input
Operating Labor Rate	O	($/hr)	60	<--- User Input (Labor cost including all benefits)
Transportation, Storage, & Monitoring (TS&M)	P	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = 22*2080*O/(A*1000)	$	3.92	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.6*0.025/(B*A*1000)	$	8.53	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.22	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**12.67**	Total Fixed O&M costs
Variable O&M Cost			
VOMS ($/MWh) = L * E / A	$	1.23	Variable O&M costs for solvent
VOMTS ($/MWh) = P * E / A	$	3.51	Variable O&M costs for transportation, storage, and monitoring
VOMP ($/MWh) = K * 1000 * M / A	$	4.37	Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue
VOMM ($/MWh) =I * 60 / 1000 * N / A	$	0.21	Variable O&M costs for makeup water
VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM	**$**	**9.31**	Total Variable O&M costs

Annual Capacity Factor =	0.85	
Annual MWhs =	5,212,200	
Annual Heat Input MMBtu =	34,713,252	
Annual Ton CO2 Created =	2,030,725	
Annual Ton CO2 Removed =	1,827,653	at removal efficiency = 90%
Annual Ton CO2 Emission =	203,073	
Annual Avg CO2 Emission Rate, lb/MWh =	78	based on original gross unit load [A]

Annual Capital Recovery Factor = 0.082	CO2 Capture	*from DOE 2019 BBS 12B*
Annual Capital Cost (Including AFUDC), $ =	50,885,000	
Annual FOM Cost, $ =	8,869,000	
Annual VOM Cost, $ =	48,527,000	
Total Annual CO2 Capture Cost, $ =	108,281,000	
Capital Cost, $/MWh =	9.76	
FOM Cost, $/MWh =	1.70	
VOM Cost, $/MWh =	9.31	
Total CO2 Capture Cost, $/MWh =	20.77	
Capital Cost, $/ton =	28	
FOM Cost, $/ton =	5	
VOM Cost, $/ton =	27	
Total CO2 Capture Cost, $/ton =	59	

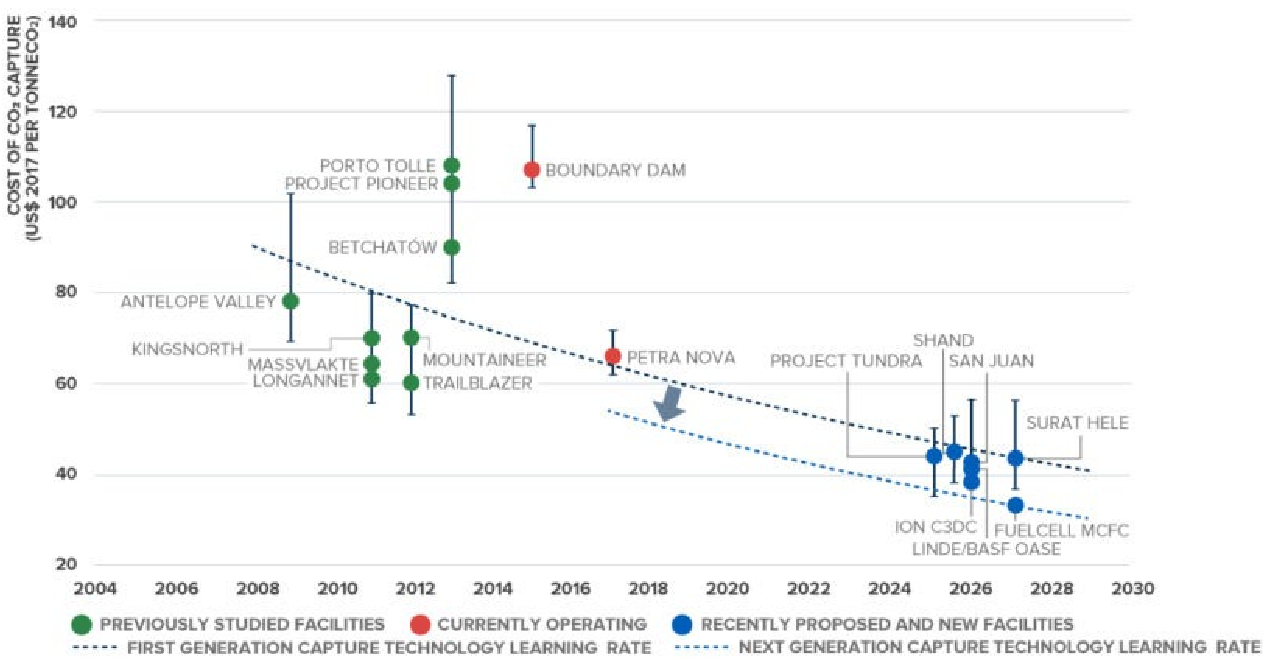
Appendix A – Amine Capture Cost Comparison

HISTORICAL PERSPECTIVE

Post-combustion CO_2 capture technology has been developed and advanced on power plant applications over the last few decades. With two large-scale applications installed in North America on coal-fired power plants, post-combustion amine-based capture has been proven to be a technically feasible technology to implement. In the last five years, since the Petra Nova project, the U.S. Department of Energy (DOE) has actively engaged various amine-solvent technology suppliers to conduct front-end, engineering and design (FEED) studies to advance the technology and further refine and reduce the overall cost of capture.

The Global CCS Institute has tracked publicly available information on previously studied, executed, and proposed CO_2 capture projects. Recent pricing is approximately \$40/tonne (\$36/ton) on average for coal plants (excluding transportation, storage, and monitoring), compared to Petra Nova and Boundary Dam whose actual costs were reported to be \$65 and \$105/tonne (\$59 and \$95/ton), respectively, see Figure 1.[1]

Figure 1 — Levelized Cost of CO_2 Capture for Large Scale Post-Combustion Facilities at Coal-Fired Power Plants



Sections below discuss high-level cost comparisons for the application of amine-based CO_2 capture system considering retrofit vs. new application on both coal and NGCC facilities.

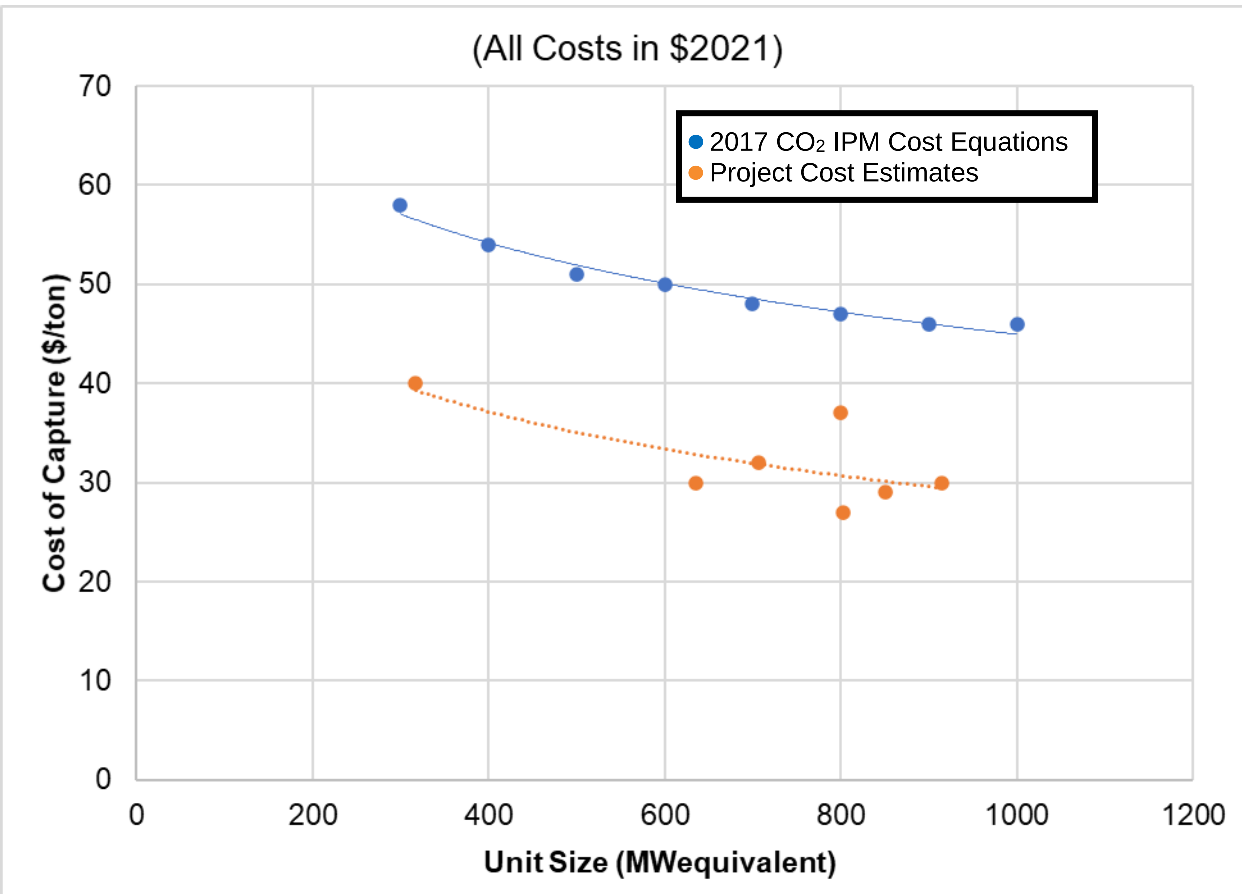
[1] Global Status of CCS 2019: Targeting Climate Change. Figure 8.
https://ccsknowledge.com/pub/Publications/Global_Status%20of_CCS_2019%20_GCCSI.pdf

Appendix A – Amine Capture Cost Comparison

RETROFIT COST COMPARISON

In 2016, S&L developed a model to predict the cost to retrofit and operate a CO_2 capture system at existing coal-fired power plants. Since that time, cost of capture has come down incrementally, based on recent project feasibility and FEED studies. S&L compared recent project estimates from 2020-2021 to the "IPM Model – Updates to Cost and Performance for APC Technologies, CO_2 Reduction Cost Development Methodology" dated Final, February, 2017 (referred to as "2017 CO_2 IPM Cost Equations"), as shown in Figure 2. The 2017 CO2 IPM Cost Equations were developed and applied to coal-fired applications only. Based on the advancements within the industry in terms of optimization of energy demand, solvent makeup costs, financing costs, and lessons learned from pilot facilities, all recent project costs for coal-fired retrofits are noticeably lower than the original curve, by approximately 20%[2].

Figure 2 —Recent Project Cost Estimate Comparison to 2017 CO_2 IPM Cost Equations



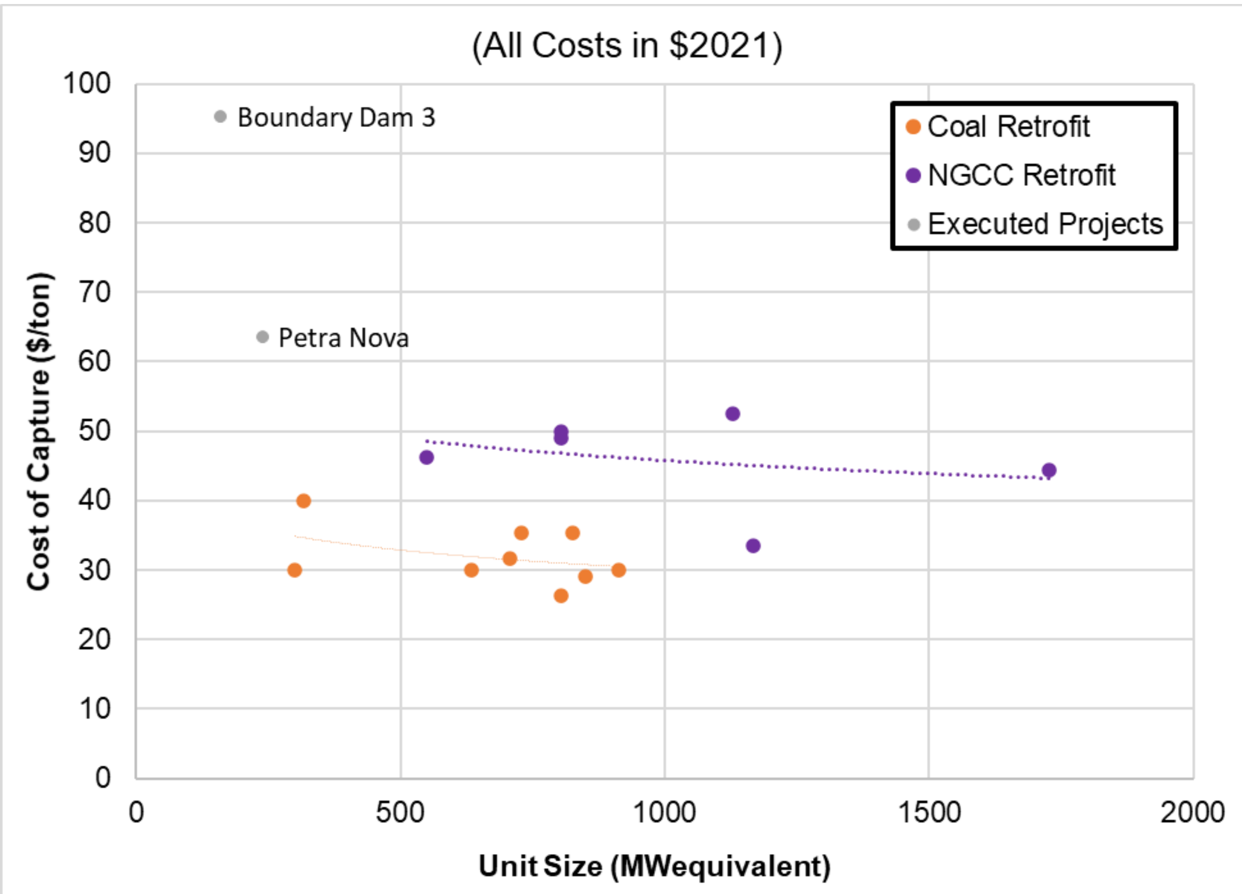
Depending on the approach for implementing CO_2 capture, the cost of capture for coal-fired units is generally in the range of $30-50/tonne ($27-45/ton).[3] The reduction in costs is due primarily to technology innovations

[2] For this evaluation all costs are representative of 2021 dollars and excludes current market conditions; all other default parameters in the IPM model were held constant. This comparison excludes any cost of transportation, storage, and monitoring (TS&M). In 2022, inflation has resulted in an increase of CO_2 capture system costs of 15-20% on average; however, this continues to fluctuate.
[3] For this evaluation all costs are representative of 2021 dollars and excludes current market conditions. The cost of capture excludes costs related to transportation, storage, and monitoring (TS&M).

and lessons learned from implemented projects.

Amine CO_2 capture technology suppliers have made advancements in their solvent and process design that allows for better capture of CO_2 at low partial pressures. With these considerations, S&L has seen a large reduction in overall cost of capture for NGCC facilities recently, however, there are still limitations to the technology and overall economics. As seen in Figure 3, costs estimated for application of CO_2 capture at a NGCC facility are significantly higher on an evaluated cost ($/tonne or $/ton) than on a coal-fired facility, approximately 50%, due to economies of scale and CO_2 concentration.

Figure 3 — CO_2 Capture Retrofit Costs on Coal-Fired v. NGCC Units



NEW FACILITY COST COMPARISON

The cost of CO_2 capture implementation constructed in parallel with new units is expected to be on the lower end of the cost ranges provided in the previous sections, as the arrangement, design, and integration with the base facility will be optimized. If new NGCC units are built with CO_2 capture, the capacity factor can be expected to be relatively high, similar to a base loaded facility (e.g. ≥85%); this also improves the overall capture economics. However, as in retrofit applications, the costs estimated for application of CO_2 capture at a new NGCC facility are significantly higher on an evaluated cost ($/tonne or $/ton) than on a coal-fired facility.

Appendix A – Amine Capture Cost Comparison

Table 1: Comparative Cost of Capture

Coal w/ Carbon Capture-90%	Units	New Unit ATB2021	New Unit EIA - S&L	S&L Retrofit Experience
Gross Unit Size	MW	Not specified	831	700
Net Nominal Capacity	MW	650	650	455
Net Nominal Heat Rate	Btu/kWh	10,830	12,507	14,776
CO_2 Emission Rate	lb/MMBtu	20.23	20.60	21.10
Capital Cost[1,2]	$/kW-net	$4,698	$5,876	$3,202
Fixed O&M Cost[1]	$/kW-year	$122.00	$59.54	$41.27
Variable O&M Cost[1,6]	$/MWh	$14.00	$10.98	$21.94
Fuel O&M Cost[5]	$/MWh-net	$24.12	$27.85	$0.00
Cost of Capture[3,4]	$/tonne	$39.08	$39.31	$48.81
	$/ton	$35.45	$35.65	$44.27
NGCC w/ Carbon Capture-90%	**Units**	**New Unit ATB2021**	**New Unit EIA - S&L**	**S&L Retrofit Experience**
Frame Type	---	Not specified	H-Class, 1x1x1	F-Class, 3x1
Net Nominal Capacity	MW	646	377	632
Net Nominal Heat Rate	Btu/kWh	7,160	7,124	9047
CO_2 Emission Rate	lb/MMBtu	11.86	11.70	11.5
Capital Cost[1,2]	$/kW-net	$2,435	$2,481	$1,267
Fixed O&M Cost[1]	$/kW-net-year	$65.00	$27.60	$21.64
Variable O&M Cost[1,6]	$/MWh-net	$6.00	$5.84	$8.29
Fuel O&M Cost[5]	$/MWh-net	$31.65	$31.49	$0.00
Cost of Capture[3,4]	$/tonne	$82.28	$68.24	$58.50
	$/ton	$74.63	$61.89	$53.06

Notes:

[1]All cost values in 2019 dollars, 2019 Case shown for ATB2021.
[2]All capital cost values are presented as overnight costs.
[3]Assumed capacity factor of 85%.
[4]Assumed evaluation period of 20 years and 5.0% interest rate.
[5] All cases have fuel O&M costs added using NETL assumptions ($51.96/ton coal, 11,666 Btu/lb coal; $4.42/MMBtu gas, 22,483 Btu/lb gas); for retrofit case, no additional fuel usage is expected.
[6]All steam turbine and aux power derate for the retrofit cases are accounted for within the variable O&M.

Note that there are many different assumptions considered in the EIA and the example retrofit evaluations making this difficult to compare on a line by line basis. Unit derate costs due to steam turbine derates or additional aux power demand due to carbon capture are typically covered in the variable O&M (VOM) costs; in this case, the retrofit VOM is noticeably higher than the new unit VOM. Instead of including derates for the new unit in VOM, it is covered separately in the EIA evaluation as part of fuel-based O&M costs. When reviewing retrofit cases, often times property tax, insurance, and administrative impacts are excluded from the fixed O&M (FOM) costs since the facility is expected to absorb that cost. While the retrofit cases suggest that the FOM is lower, in reality, FOM costs for all four cases would be expected to be similar.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, March 15, 2023 4:17 PM
To: Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Good afternoon,

Thank you for submitting the subject referenced RINs in ROCIS. Can you please provide a list of supporting files to help keep me and other reviewers organized?

Many thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Hutson, Nick <[redacted]epa.gov>
Sent: Wednesday, March 15, 2023 4:33 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Steph,

I believe Lisa is out of the office for the rest of the day. But, I expect she'll be able to get you a list first thing tomorrow morning.

Nick

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]

From: Thompson, Lisa
Sent: Wednesday, March 15, 2023 4:41 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan

<[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Hi Steph,

Here is the list of files uploaded to ROCIS. We've included pdfs for the reg text files with redline strikeout to ensure you can see the edits.

1. Preamble "EO 12866_111 EGU_2060-AV09 and 2060-AV10_NPRM_Preamble_20230315"
2. RIA "EO 12866_111_EGU_2060-AV09_and_2060-AV10_NPRM_RIA_20230315"
3. ROCIS Spreadsheet "EO 12866_111_EGU_2060-AV09_and_2060-AV10_NPRM_RIA_20230315_RIA_spreadsheet"
4. Reg Text - Proposed TTTT.docx (includes redline)
5. Reg Text - Proposed TTTT.pdf (includes redline)
6. Reg Text - Proposed TTTTa.docx (includes redline)
7. Reg Text - Proposed TTTTa.pdf (includes redline)
8. Reg Text - Proposed UUUUa
9. Reg Text - Proposed UUUUb
10. TSD - GHG Mitigation Measures - 111(b)
11. TSD - GHG Mitigation Measures - 111(d)
12. TSD - Natural Gas And Oil Steam EGUs
13. TSD - Power Sector Trends
14. TSD - Resource Adequacy & Reliability Assessment
15. TSD - Simple Cycle Stationary Combustion Turbine EGUs
16. TSD - Hydrogen in Combustion Turbine EGUs
17. TSD - Efficient Generation Combustion Turbine EGUs
18. ICR - supporting statement
19. ICR – spreadsheet
20. Memo - Federalism Pre-Proposal Consultation Summary
21. Memo - S&L HRI Cost
22. Memo - S&L NG Co-Firing
23. Memo - Stakeholder Outreach

Look forward to working with you on this review. Please let us know if you want to schedule an introductory briefing for the interagency reviewers on this package.

Lisa

From: Hutson, Nick <[redacted]epa.gov>
Sent: Wednesday, March 15, 2023 4:42 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Oh … thank you Lisa!

Nick

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, March 15, 2023 4:49 PM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Thank you so much! Is it possible to please also have word files for the reg text via email? I don't see the RIA and ICR spreadsheets in ROCIS – I wonder if they were stripped out. Can EPA please try those again?

From: Thompson, Lisa
Sent: Wednesday, March 15, 2023 4:55 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Of course. I'll ask our folks to re-upload the spreadsheets in ROCIS, but attaching here in case there's an issue with one of our systems.

Please find attached:

1. Reg Text - Proposed TTTT
2. Reg Text - Proposed TTTTa
3. Reg Text - Proposed UUUUa
4. Reg Text - Proposed UUUUb
5. ROCIS Spreadsheet "EO 12866_111_EGU_2060-AV09_and_2060-AV10_NPRM_RIA_20230315_RIA_spreadsheet"
6. ICR – spreadsheet

From: Thompson, Lisa
Sent: Thursday, March 16, 2023 8:49 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB

<[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Hi Steph – can you reopen ROCIS for us to re-submit the two spreadsheets?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, March 16, 2023 9:08 AM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Hi Lisa,
Thank you! Yes, ROCIS is open. I realized the RIA spreadsheet is just the economics table and has been entered into ROCIS already – so no need to upload that one.
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, March 16, 2023 9:40 AM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: EPA RIN 2060-AV09 and 2060-AV10 Briefing

Good morning,
Would 3/21 at 9am work for an inter-agency briefing on this rule? Alternatively, 3/21 at 3pm?
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Thompson, Lisa
Sent: Thursday, March 16, 2023 9:50 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 Briefing

9am on 3/21 works for us. Thanks!

From: Muellerleile, Caryn <[redacted]epa.gov>
Sent: Thursday, March 16, 2023 1:26 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Dunkins, Robin <[redacted]epa.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Hi Steph,

EPA has transmitted the ICR worksheet through ROCIS because it is ready and available, but we cannot commit to such availability of ICR information for all EO 12866 review packages.

Please let me know if you have any questions, and welcome back!

Caryn Muellerleile, Director
Regulatory Management Division
Office of Regulatory Policy and Management
Office of Policy
U.S. Environmental Protection Agency
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, March 16, 2023 2:08 PM
To: Muellerleile, Caryn <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Dunkins, Robin <[redacted]epa.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Thanks Caryn and team. We appreciate it here and when available.
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 17, 2023 8:36 AM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Miller, Sofie E. EOP/OMB
Subject: EPA/OAR 111 GHG Emissions NPRM inter-agency briefing
When: Tuesday, March 21, 2023 9:00 AM-10:00 AM (UTC-05:00) Eastern Time (US & Canada).

From: Thompson, Lisa
Sent: Friday, March 17, 2023 9:41 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA/OAR CAA 111 GHG Emissions NPRM inter-agency briefing

Hi Steph ---

I have two zoom invites from you. One is Tuesday 9-10, and one is Tuesday 9 – Wednesday 10. I assume the first is the correct one, but want to double check before I invite the EPA team.

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 17, 2023 10:09 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: Re: EPA/OAR CAA 111 GHG Emissions NPRM inter-agency briefing

Hi! I'm having trouble with my zoom this morning - sorry to be spamming you! I'll confirm the correct one soon.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 17, 2023 3:15 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; [redacted]
Subject: CAA 111 GHGs - DOJ call

Good afternoon and happy Friday! Is EPA available for a call with DOJ to discuss the CAA 111 GHG Emissions NPRM on Monday, April 3? We and DOJ's ENRD is available in the 11:30am-3pm block. I think we'll need at least 2 hours but am happy to ask for a longer window if you think it's advisable. DOJ is still developing their comments and so I don't have a clear sense of how much time is needed.
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 17, 2023 4:46 PM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Hi all,
Are there actual RLSO changes to TTTTa or just the comment bubbles? I can't see the RLSO in either the word or the ROCIS PDF, but maybe there is none. Thanks,
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 17, 2023 4:52 PM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; Garcia, Jacob A. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Nevermind, I'm realizing TTTTa is new. Are the comment bubbles comparing to current TTTT? Feel free to call me if easier.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 17, 2023 11:04 AM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Miller, Sofie E. EOP/OMB
Subject: CAA 111 GHG Emissions NPRM Inter-agency briefing
When: Tuesday, March 21, 2023 9:00 AM-10:00 AM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

Hi EPA team,
Sorry I'm having technical difficulties this AM. Please use the zoom information below for our 9am inter-agency briefing on Tuesday 3/21. Thanks!

From: Thompson, Lisa
Sent: Friday, March 17, 2023 8:02 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; [redacted]
Subject: RE: CAA 111 GHGs - DOJ call

Hi Steph –

Yes, the team is available during that window. I've blocked the whole 11:30-3 slot on EPA's calendars, so we can adjust the time once DOJ develops their comments and knows how much time is needed. Does that work for you?

Thanks,
Lisa

From: Thompson, Lisa
Sent: Friday, March 17, 2023 8:06 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>; [redacted]
Subject: RE: EPA RIN 2060-AV09 and 2060-AV10 ROCIS submission

Hi Steph,

Yes, the comment bubbles explain what each change from current TTTT to the regulatory text is intended to accomplish. We've included this in the past to help the regulated community understand what we are proposing and to make sure it does what we intend.

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Saturday, March 18, 2023 11:23 AM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; [redacted]
Subject: Re: CAA 111 GHGs - DOJ call

That sounds great, thanks.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 20, 2023 9:04 AM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Miller, Sofie E. EOP/OMB
Subject: DOJ/EPA CAA 111 GHG Emissions NPRM call
When: Monday, April 3, 2023 11:30 AM-3:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

Please hold this block, timing TBD.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 20, 2023 9:04 AM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Miller, Sofie E. EOP/OMB; Garfinkle, Stacey; Marks, Matthew; Profeta, Timothy; Greenglass, Nora; Adamantiades, Mikhail; Weatherall, Grace; Huetteman, Justine
Subject: DOJ/EPA CAA 111 GHG Emissions NPRM call
When: Monday, April 3, 2023 1:30 PM-3:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

Timing confirmed for 1:30pm.

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Tuesday, March 21, 2023 7:32 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: 111 EGU rule on Reginfo.gov

Hi Steph,

This is how our rule appears on reg info --- is it possible to update this, or add an entry for the second RIN number (2060-AV10) to more accurately show what we've submitted?

AGENCY: EPA-OAR **RIN:** 2060-AV09 **Status:** Pending Review
TITLE: Amendments to the NSPS for GHG Emissions From New, Modified, & Reconstructed Stationary Sources: EGUs
STAGE: Proposed Rule **ECONOMICALLY SIGNIFICANT:** Yes
RECEIVED DATE: 03/15/2023 **LEGAL DEADLINE:** None

Here's what we submitted:

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

RIN 2060-AV09 and 2060-AV10

Thanks!
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, March 21, 2023 8:57 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: 111 EGU rule on Reginfo.gov

I can check. Reginfo defaults to the latest agenda publication and I'm not sure if it can show both RINs in the meta-data but I think it can be added to the title. Are you all able to join the briefing?

From: Thompson, Lisa
Sent: Tuesday, March 21, 2023 9:01 AM
To: [redacted]omb.eop.gov
Subject: Slides for today

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, March 21, 2023 9:07 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Slides for today

Thanks! I pushed these out to reviewers.

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Tuesday, March 21, 2023 10:09 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: 111 EGU rule on Reginfo.gov

Thanks for looking into this. If the title could be updated to reflect the package, that would be great! Apologies for the trouble the 2 RIN numbers are causing.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, March 21, 2023 3:25 PM

To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: 111 EGU rule on Reginfo.gov

Hey Lisa,
The title field has a 200 character limit, which is a good excuse to lament the lack of a pithy title for this rule. Is EPA open to heavy abbreviation? I.e., NSPS for GHG Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; EGs for GHG Emissions from Existing Fossil Fuel-Fired EGUs; and Repeal of the ACE Rule (RIN 2060-AV09 and 2060-AV10)

Thanks.
From: Thompson, Lisa
Sent: Tuesday, March 21, 2023 3:54 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: 111 EGU rule on Reginfo.gov

Yes, we're open to heavy abbreviation – what you suggested works for us!

From: Thompson, Lisa
Sent: Wednesday, March 22, 2023 7:27 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: 111 EGU rule on Reginfo.gov

Hi Steph –

It looks like a digit was dropped in the second RIN number – can you send this last small change forward? Thanks so much for fixing this for us!

NSPS for GHG Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; EGs for GHG Emissions from Existing Fossil Fuel-Fired EGUs; and Repeal of the ACE Rule (RIN 2060-AV09 and 2060-AV10)

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, March 22, 2023 10:14 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 GHGs - reviewer requests

Hi EPA team,
Please see below for two requests from reviewers. Thanks so much.
Steph

1) Can you please provide the Sargent and Lundy document cited in footnote 65 of the "TSD - GHG Mitigation Measures - 111(d)" document that was provided for review?
2) We are confused by our observation that Table 3-5 and Table 4-2 in the RIA seem to present different emissions projections for the less stringent and more stringent scenarios. The numbers presented as being for the "less stringent" scenario in Table 3-5 are the same as the numbers presented for the "more stringent" scenario in Table 4-2 (see below). So we're wondering which is correct, and it would be helpful to know as we work on our first-round comments.

RIA pg. 3-12: "The emission reductions follow an expected pattern: the less stringent alternative produces smaller emissions reductions than the proposal, and the more stringent alternative results in more CO_2 emissions reductions."
(the text about the less stringent alternative seems contradicted by the numbers in the table itself)

Table 3-5 EGU Annual CO_2 Emissions and Emissions Changes (million metric tonnes) for the Baseline and the Illustrative Scenarios from 2028 - 2040 [46]

Annual CO_2	Total Emissions				Change from Baseline		
(Million Metric Tonnes)	Baseline	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
2028	1,222	1,212	1,222	1,209	-10	0	-14
2030	972	882	865	871	-89	-107	-100
2035	608	572	566	574	-37	-42	-35
2040	481	458	459	457	-24	-23	-24

RIA pg. 4-15:

Table 4-2 Annual CO_2 Emissions Changes (million metric tonnes) for the Illustrative Scenarios from 2028 - 2042

	Million Metric Tons of CO_2		
Emissions Year	Proposal Scenario	Less Stringent Scenario	More Stringent Scenario
2028	10.1	8.7	0.5
2029	89.2	82.6	106.7
2030	89.2	82.6	106.7
2031	89.2	82.6	106.7
2032	36.7	35.2	41.8
2033	36.7	35.2	41.8
2034	36.7	35.2	41.8
2035	36.7	35.2	41.8
2036	36.7	35.2	41.8
2037	36.7	35.2	41.8
2038	23.7	22.0	22.8
2039	23.7	22.0	22.8
2040	23.7	22.0	22.8
2041	23.7	22.0	22.8
2042	23.7	22.0	22.8

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Thompson, Lisa
Sent: Thursday, March 23, 2023 8:01 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 GHGs - reviewer requests

Hi Steph – Sorry for the delay. See responses below:

1) We're still determining if we can share this memo publicly. The key staff will be in the office tomorrow so I'll follow up when I know more.
2) We looked into this and found errors in the CO_2 emission reduction reporting for the Less Stringent and More Stringent scenarios in Table 3-5, and also in Table 0-1. The values in Table 4-2 are correct. Corrected versions of Tables 0-1 and 3-5 are presented below, and will be corrected in the first RIA passback.

In addition, we wanted to provide more information following up on the CCS cost discussion from Tuesday:

- When calculating costs for BSER determination EPA does not rely on IPM projections. However, when assessing compliance outcomes and costs, EPA does rely on IPM projections.
- CCS costs for existing fossil-fired generation and sequestration potential as it relates to distance from existing resources are a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details on the costs of CCS for existing coal-fired generating units and potential builds, please see chapter 6 of the IPM documentation, available at: [redacted] Please note that the documentation does not include subsidies for carbon sequestration available under the IRA, which offers a credit of $85/metric ton for qualified carbon oxide permanently stored in secure geological storage and $60/metric ton for qualified carbon oxide used for enhanced oil or natural gas recovery projects.
- As outlined in section 3.6.3 of the RIA, 12 GW of coal-fired EGUs who plan to operate beyond 2040 are subject to the long-term existing coal-fired steam generating units subcategory, and as such install CCS (reflecting 3 GW incremental to the baseline).

Thanks,
Lisa

Table 0-1 Projected EGU Emissions and Emissions Changes for the Baseline and the Three Illustrative Scenarios for 2028, 2030, and 2035, and 2040 [a]

	CO_2 (million metric tonnes)	Annual NO_X (thousand short tons)	Ozone Season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)
Proposal					
2028	-10	-7	-3	-12	-1
2030	-89	-64	-22	-107	-6
2035	-37	-21	-7	-41	-1
2040	-24	-13	-4	-30	-1
Less Stringent					
2028	-9	-7	-3	-9	-1
2030	-83	-61	-20	-99	-5
2035	-35	-20	-7	-38	-1
2040	-22	-12	-4	-27	-1
More Stringent					
2028	0	3	1	-4	0
2030	-107	-61	-20	-114	-5
2035	-42	-22	-7	-41	-2
2040	-23	-13	-4	-30	-1

[a] This analysis is limited to the geographically contiguous lower 48 states.

Table 3-5 EGU Annual CO_2 Emissions and Emissions Changes (Million Metric Tonnes) for the Baseline and the Illustrative Scenarios from 2028 - 2040

Annual CO_2	Total Emissions				Change from Baseline		
(Million Metric Tonnes)	Baseline	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
2028	1,222	1,212	1,214	1,222	-10	-9	0
2030	972	882	889	865	-89	-83	-107
2035	608	572	573	566	-37	-35	-42
2040	481	458	459	459	-24	-22	-23

From: Thompson, Lisa
Sent: Friday, March 24, 2023 9:14 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 GHGs - reviewer requests

Hi Steph,

Please find the S&L memo attached.

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 24, 2023 2:46 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: TSD request

Hi EPA team,
I saw this TSD referenced in the RIA *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* but I don't see it in ROCIS. Can you advise?
Copying Mike for coverage as Sofie is out next week.
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Friday, March 24, 2023 3:02 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: TSD request

Hi Steph,

We've provided the citation for this TSD in the RIA reference section, but it looks like the hyperlink takes you to the wrong site. Here's the correct link: [redacted]

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, March 24, 2023 3:16 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: TSD request

Oh thank you! Good to see we've seen it already.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 27, 2023 12:14 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: 111 GHGs NPRM - counsel call request

Hi EPA team,
Counsel has requested a one hour call on this NPRM. We could speak as early as 4:30pm today or we are available at 12pm on Thursday 3/30 or from 3:30-5:30pm on Tuesday 4/4. All times Eastern.
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 27, 2023 12:27 PM
To: Hutson, Nick <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: Re: 111 GHGs NPRM - counsel call request

Thanks! Are you sure? I see MATS on for tomorrow but it may be my error.

On Mar 27, 2023, at 12:17 PM, Hutson, Nick <[redacted]epa.gov> wrote:

Hi Steph,

We can't do today at 4:30 PM as we already have a call w/ WHC on MATS at that same time.

I'll work w/ Lisa to check availability for the other suggested dates/times.

Nick

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, March 27, 2023 12:30 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: 111 GHGs NPRM - counsel call request

Ooops! You're right … MATS is tomorrow. Sorry!

I'll look at calendars re today and get back to you.

Nick

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]

On Mar 27, 2023, at 1:19 PM, Thompson, Lisa <[redacted]epa.gov> wrote:

Hi Steph,

4/4 from 4-5pm is best for us.

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 27, 2023 1:24 PM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Ciccarone, Mike J. EOP/OMB <[redacted]omb.eop.gov>
Subject: Re: 111 GHGs NPRM - counsel call request

Thanks! White House counsel primarily but others may join. I think we have a separate DOJ cal on the books already. Steph

From: Gilbreath, Jan <[redacted]epa.gov>
Sent: Monday, March 27, 2023 12:50 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: Quick question on the EGU GHG 111 proposals

Steph,
Can you tell me when interagency comments are due to OMB on this action? I forgot to ask you last week, but I need to pin this down for management.

Also, we have an April 3 meeting scheduled with DOJ. Are we also scheduling a separate call with OMB counsel?

Thanks,

Jan

From: Tatham, Steph J. EOP/OMB
Sent: Monday, March 27, 2023 1:44 PM
To: 'Gilbreath, Jan' <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Quick question on the EGU GHG 111 proposals

Hi Jan,
Comments are due to me at COB on 3/29 but I anticipate it will take some time to work through the comments and get them to EPA. TBD but it's also possible our RIA comments will take a bit longer.
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 27, 2023 1:52 PM
To: Gilbreath, Jan <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Quick question on the EGU GHG 111 proposals

Oh and to your second question – we'll have separate calls with WHCO and DOJ. Both scheduled.
Thanks,
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, March 27, 2023 1:54 PM
To: Tatham, Steph J. EOP/OMB; Gilbreath, Jan; Thompson, Lisa; Hutson, Nick
Subject: EPA/WHCO CAA 111 GHG emissions NPRM
When: Tuesday, April 4, 2023 4:00 PM-5:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, March 30, 2023 3:40 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: Call me?

Hi Lisa and Nick,
Could one of you please call me at [redacted]? Thanks!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Saturday, April 1, 2023 10:43 AM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: CAA 111 GHGs NPRM - preamble comments

Good morning,
Please find attached initial preamble comments from a nearly complete set of inter-agency reviewers. I may receive additional feedback from one to two more commenters early next week.
I've flagged several areas where calls were requested and will follow up separately to schedule. I'm also attaching a cover note shared by TVA.
Please also find attached comments on draft proposed TTTT (limited to what we think is a metric conversion error), proposed TTTTa (I tried to highlight the new comments here), and proposed UUUUb.
Many thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Saturday, April 1, 2023 5:45 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: TSD comments

Good evening,
Please find attached comments on a few of the TSDs.
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 3, 2023 7:07 PM
To: Tatham, Steph J. EOP/OMB; Hutson, Nick; Thompson, Lisa; Gilbreath, Jan
Subject: OIRA/EPA CAA 111 GHGs
When: Tuesday, April 4, 2023 2:30 PM-3:30 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 3, 2023 7:07 PM
To: Tatham, Steph J. EOP/OMB; Hutson, Nick; Thompson, Lisa; Gilbreath, Jan

Cc: Goffman, Joseph; Marks, Matthew; Stenhouse, Jeb; Huetteman, Justine; Keaveny, Brian
Subject: OIRA/EPA CAA 111 GHGs
When: Tuesday, April 4, 2023 2:00 PM-3:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Thompson, Lisa
Sent: Tuesday, April 4, 2023 7:56 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OIRA/EPA CAA 111 GHGs

If there's any way to move this to 2-3 that would be better for our key OGC staff. If not, we'll have a handful of folks leave halfway through. We'll make it work either way!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 10:34 AM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: 2nd comment tranche

Hi Nick, Lisa, and Jan,
We have a second set of comments on the preamble now that some stragglers are in. Would you like those on top of the comments previously shared or is a separate preamble document ok?
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Tuesday, April 4, 2023 10:37 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: 2nd comment tranche

Separate preamble document is preferred, but we can work with whatever is easiest for you!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 10:38 AM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: 2nd comment tranche

Great, that's my preference too – thanks!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 1:32 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: OMB OGC / DOE calls

Hi Lisa,

OMB OGC has some minor comments they'd like to convey after the WHCO call today to avoid duplication. I doubt we'll need a full hour but I'm not sure yet how much time we'll need. Is EPA available tomorrow if any of the following windows:
9:30-10:30am
1:30-2:30pm
3:30-5pm

I'm still waiting on DOE, but if you provide EPA's full availability in the windows above maybe we can use one of these times for DOE.

Thanks!
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Tuesday, April 4, 2023 2:38 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>
Subject: I think you asked some more detailed technical/modeling questions on hydrgoen

That we did not answer. I didn't fully understand the comments or I'd just e-mail you a reply. Happy to follow up outside of this call (or if in the very unlikely case that we actually have time left, at the end of this call).

- Kevin [redacted]

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Tuesday, April 4, 2023 3:02 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OMB OGC / DOE calls

Hi Steph,

Let's do 9:30-10:30 for the OMB OGC call. If possible, let's schedule the DOE call during the 3:30-5 window.

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 4:37 PM
To: Tatham, Steph J. EOP/OMB; Desai, Anuj C. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Subject: EPA/OMB OGC CAA 111
When: Wednesday, April 5, 2023 4:00 PM-5:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

*Bumping OGC call to 4-5

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 5:05 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OMB OGC / DOE calls

Ok, DOE has slipped to Friday so I bumped OGC to PM. Can EPA do 10am-11am for WHCO?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 5:15 PM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Roberts, Martha G. EOP/OMB
Cc: Miller, Sofie E. EOP/OMB; DeFigueiredo, Mark; Weatherall, Grace; Marcy, Cara; Huetteman, Justine; Weatherhead, Darryl (she/her/hers)
Subject: EPA/DOE CAA 111 GHGs NPRM
When: Friday, April 7, 2023 10:00 AM-11:00 AM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 5:16 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OMB OGC / DOE calls

Hi team,
On DOE – just wanted to let you know I asked DOE to take their policy issues at the top and then turn to the technical. I will reiterate when we kick things off. DOE confirmed they will have policy officials (non-career) on the call but also clarified that they aren't elevating – it's just a matter of expertise.
Thanks,
Steph

From: Thompson, Lisa
Sent: Tuesday, April 4, 2023 5:16 PM
To: 'Tatham, Steph J. EOP/OMB' <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OMB OGC / DOE calls

Yes, and for OGC in the afternoon, can do between 3:45-5?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 5:18 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OMB OGC / DOE calls

Great. Yep, I pushed OGC to 4 – hopefully the calendar invite came through. Are you wanting an extra 15 minutes?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 5:18 PM
To: Tatham, Steph J. EOP/OMB; Ceronsky, Megan M. EOP/WHO; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Desai, Anuj C. EOP/OMB
Subject: EPA/WHCO CAA 111 NPRM
When: Wednesday, April 5, 2023 10:00 AM-11:00 AM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 6:08 PM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: CAA 111 preamble - additional comments

Hi EPA team,

We had a few stragglers on the draft CAA 111 GHGs NPRM preamble, please find those comments attached. Please note that PHMSA may have comments to convey in our call this week (still waiting on times).
I still owe you the RIA and a couple of TSDs. Hoping to send those tonight or tomorrow morning. We haven't received any comments on the Simple Cycle Stationary Turbine TSD so it's just the GHG mitigation measures (b and d) left.

Thanks,
Steph

Steph Tatham

OIRA Policy Analyst
[redacted]

From: Thompson, Lisa
Sent: Tuesday, April 4, 2023 7:37 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: OMB OGC / DOE calls

No, 4 is great. Our OGC staff had a conflict until 3:45 so 4 is perfect. I just missed the earlier email – sorry!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 10:44 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: CAA 111 GHGs NPRM - GHG mitigation measures TSDs

Good evening,
Please find attached inter-agency comments on the 111(b) and 111(d) GHG mitigation measures TSDs.
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 11:08 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: CAA 111 GHGs NPRM - Additional stand-alone comments

Good evening,
Here are some straggler stand-alone comments on the NPRM and preamble that did not integrate well into the redlined version with comments shared earlier today. Please let us know if discussion would be helpful.
Thanks,
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 4, 2023 11:17 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>

Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 GHGs NPRM - preamble comments

Hi EPA team,

I noticed a minor error in these comments. Please replace the duplicative comment associated with this sentence:

> Co-firing hydrogen at a combustion turbine when that hydrogen is produced with large amounts of GHG emissions would yield the anomalous result of increasing overall GHG emissions, compared to combusting solely natural gas at the combustion turbine. Therefore, in evaluating a "system of emission reduction" of co-firing hydrogen, the GHG emissions from producing the hydrogen should be recognized to determine whether co-firing that hydrogen is the "best" system of emission reduction, within the meaning of CAA section 111(a)(1).

With this comment:

> This is an important point and clearly made. It seems to clearly highlight the importance of defining low-GHG H2 as part of the rulemaking, contra the discussion on p233 regarding not needing to define a low-GHG standard.

This comment should be replaced (in its second occurrence):

This section needs a fuller discussion of the energy requirements of H2 production and the magnitude of these requirements compared to projected growth in low-carbon generation to 2035

Thanks!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 5, 2023 9:19 AM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: CAA 111 NPRM BSER determinations

Hi Lisa,

What metric is EPA using for cost-effectiveness in the BSER determinations for this rule? Is that typical? If atypical, is it precedented? We suggest finding a home in the preamble for the language describing EPA's approach to cost-effectiveness in this rule. Can EPA please also provide a summary table of the cost-effectiveness for the various technologies that points the reader to the relevant TSD discussion? As an example: I think I found the cost per MWh for low-GHG hydrogen on p. 31 of the hydrogen TSD, but I really had to go hunting for it, and I'm not sure if that is what EPA is using for BSER cost-effectiveness here.

Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 5, 2023 9:33 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: CATF - 12866 meeting

EDF is not on the invite. NRDC is coming in separately so I'm guessing EDF may too.

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 5, 2023 11:53 AM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: Phmsa call times

Hi EPA team,
Would any of the times below work for a call with PHMSA to discuss pipelines (they mentioned a CO2 rule they are working on, I'm not sure if they want to talk hydrogen too). Thanks!
Steph

Thursday, April 6 – noon to 1pm
Friday, April 7 – 11am to noon; 3-4pm

From: Thompson, Lisa
Sent: Wednesday, April 5, 2023 12:05 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: Phmsa call times

April 6, 12pm is best for us. Thanks!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 5, 2023 1:15 PM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Ford, Sean H (OST); Kohl, Elizabeth (OST)
Cc: Ciccarone, Mike J. EOP/OMB; Wilson, Kimberly C. EOP/OMB
Subject: EPA/DOT PHMSA CAA 111 GHGs NPRM
When: Thursday, April 6, 2023 12:00 PM-1:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 6, 2023 8:32 AM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Roberts, Martha G. EOP/OMB

Subject: CAA 111 next steps
When: Thursday, April 6, 2023 2:00 PM-2:30 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 6, 2023 8:34 AM
To: Tatham, Steph J. EOP/OMB; Ceronsky, Megan M. EOP/WHO; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Desai, Anuj C. EOP/OMB; Roberts, Martha G. EOP/OMB; Kymn, Christine J. EOP/OMB
Subject: EPA/WHCO CAA 111 GHGs NPRM
When: Friday, April 7, 2023 4:30 PM-5:30 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Thursday, April 6, 2023 3:23 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: PHMSA follow up

Hi Steph,

Can you pass along these sections of the rule package to PHMSA?

Thanks,
Lisa

Preamble

- VII.F.3.b.iii.(A)(5) CO2 Transport, pg 181
- VII.F.3.c.vi – EPA's proposed BSER and Definition of Low-GHG Hydrogen, pg 227
- VII.F.3.c.vii - Justification for Proposing 30 Percent Co-firing Low-GHG Hydrogen as the BSER, pg 234
- XIV.E.3 Outreach and Engagement, pg 521

Modeling documentation (ch. 6) https://www.epa.gov/power-sector-modeling/documentation-post-ira-2022-reference-case

GHG Mitigation Measures - 111(d) TSD

Lisa Thompson
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 6, 2023 3:25 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: PHMSA follow up

Yep, I think they should look at the Hydrogen TSD also, so I'll send them that. Thanks!

From: Thompson, Lisa
Sent: Thursday, April 6, 2023 6:46 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: PHMSA follow up

Thank you!

From: Tatham, Steph J. EOP/OMB
Sent: Thursday, April 6, 2023 10:14 PM
To: [redacted]epa.gov; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 econ meeting

Hi EPA team,

Can we please meet with CEA and OIRA on Monday at 2pm to discuss a few issues related to the impact analysis. We request that EPA bring NCEE, ideally Al. Amanda thought Kevin might want to join too.
Suggested agenda below

- Accounting for subsidies
- IRA/baseline
- Steam electric ELG
- ACE repeal

Thanks,
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 6, 2023 10:15 PM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Culligan, Kevin; Keaveny, Brian; Comiter, Michael; Marten, Alex; Weatherhead, Darryl (she/her/hers); Weatherall, Grace; Wayland, Robertj
Subject: EPA/EOP CAA 111 GHGs RIA
When: Monday, April 10, 2023 2:00 PM-3:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

Agenda:

- Full accounting for subsidies
- IRA/baseline
- Steam electric ELG
- ACE Repeal
- NSPS only
- H2 and NOx

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Friday, April 7, 2023 12:51 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: Understand you may be sending us additional comments on TSDs today?

I know that Lisa and Nick are both at least partially out of pocket today. If you haven't already made arrangements with Lisa, can you include me on whatever you send back so I can help make sure they get passed along to the right folks ASAP.

Thanks, (Lisa – if you already have a plan worked out and you see this, shoot me an e-mail).

- Kevin

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 7, 2023 12:54 PM
To: Culligan, Kevin <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: RE: Understand you may be sending us additional comments on TSDs today?

Hi Kevin,
Yep – I still owe you some comments on the RIA and will do!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 7, 2023 12:54 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>
Subject: RE: CAA 111 econ meeting

+ Kevin

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 7, 2023 4:13 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>
Subject: CAA 111 GHGs NPRM - RIA comments

Happy Friday EPA team,

Please find attached some comments on the RIA. Please let me know if Monday 2pm will work for the requested call. I'd like to add two more items to that agenda. If EPA thinks we need more time we can start at 1:30 over here but have a hard stop at 3.

Full accounting for subsidies
IRA/baseline
Steam electric ELG
ACE Repeal
NSPS only
H2 and NOx

Thanks,
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 11, 2023 2:38 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: Mischa

Can I confirm his last name? Thanks so much!

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Thompson, Lisa
Sent: Tuesday, April 11, 2023 2:40 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: Mischa

Mikhail "Misha" Adamantiades.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 11, 2023 5:48 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 GHGs - additional comments

Hi Lisa,
Two more minor comments attached for EPA from our straggling reviewer. No meeting is needed. More to come soon on the Energy call.
Thanks,
Steph

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 11, 2023 8:45 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: DOE call

Hi Lisa,
Is 1 or 2pm tomorrow better for EPA? DOE can do either. Thanks!

Steph Tatham
OIRA Policy Analyst

[redacted]

From: Thompson, Lisa
Sent: Tuesday, April 11, 2023 8:48 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: DOE call

2 is better for us. Thanks!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 11, 2023 2:50 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: E.O. 12866 Meeting 2060-AV09 - Amendments to the NSPS for GHG Emissions From New, Modified, & Reconstructed Stationary Sources: EGUs

Sorry, thanks – the second is a report.

I didn't realize EPA had an ANPRM on this proposal. Was there an associated FRN?

From: Thompson, Lisa
Sent: Tuesday, April 11, 2023 2:57 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: E.O. 12866 Meeting 2060-AV09 - Amendments to the NSPS for GHG Emissions From New, Modified, & Reconstructed Stationary Sources: EGUs

Not an ANPRM, but we opened a non-regulatory docket for public input. See attached and a link to docket here: [redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 12, 2023 2:32 PM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Gilbreath, Jan; Hutson, Nick; Tiedeman, Jennifer
Cc: Culligan, Kevin; Thomas, Amanda L. EOP/OMB; Kymn, Christine J. EOP/OMB; Grace-Tardy, Ami; Grumet, Stephanie; Weatherall, Grace; DeFigueiredo, Mark; Stenhouse, Jeb; Donohoo-Vallett, Paul
Subject: EPA/DOE CAA 111 GHGs NPRM - technical call
When: Wednesday, April 12, 2023 2:00 PM-2:30 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 12, 2023 9:55 PM
To: Tatham, Steph J. EOP/OMB; Miller, Sofie E. EOP/OMB; Thompson, Lisa; Tiedeman, Jennifer; Hutson, Nick; Gilbreath, Jan; Kymn, Christine J. EOP/OMB; Thomas, Amanda L. EOP/OMB; Roberts, Martha G. EOP/OMB
Subject: EPA/DOE CAA 111 CCS - technical call
When: Tuesday, April 18, 2023 3:00 PM-4:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Thompson, Lisa
Sent: Thursday, April 13, 2023 10:35 AM
To: [redacted]omb.eop.gov
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; [redacted]omb.eop.gov
Subject: CAA 111 preamble - EPA passback

Hi Steph,

Please find EPA's first preamble passback attached (both RLSO and clean). Note that we are still reworking the sections on existing gas and the ACE Repeal which will be provided in the next passback. The next passback will also include changes to hydrogen standards for new turbines.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Zaidi, Ali A. EOP/WHO <[redacted]who.eop.gov>
Sent: Friday, April 14, 2023 10:29 AM
To: Ali Zaidi; Culligan, Kevin
Subject: MEETING: CAA 111 Discussion
When: Friday, April 14, 2023 4:30 PM-5:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

PURPOSE: Discussion on CAA 111 b and d.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 17, 2023 4:23 PM
To: Miller, Sofie E. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Garfinkle, Stacey; Marks, Matthew; Profeta, Timothy; Greenglass, Nora; Adamantiades, Mikhail; Weatherall, Grace; Huetteman, Justine
Cc: Tatham, Steph J. EOP/OMB
Subject: DOJ/EPA CAA 111 GHG Emissions NPRM call No. 2
When: Wednesday, April 19, 2023 4:00 PM-5:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 17, 2023 4:32 PM
To: Miller, Sofie E. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Garfinkle, Stacey; Marks, Matthew; Profeta, Timothy; Greenglass, Nora; Adamantiades, Mikhail; Weatherall, Grace; Huetteman, Justine
Cc: Tatham, Steph J. EOP/OMB
Subject: WHCO/EPA CAA 111 GHG Emissions NPRM call No. 2

When: Thursday, April 20, 2023 12:00 PM-1:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 18, 2023 1:18 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Kymn, Christine J. EOP/OMB <[redacted]omb.eop.gov>; Thomas, Amanda L. EOP/OMB <[redacted]omb.eop.gov>; Roberts, Martha G. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA/DOE CAA 111 CCS - technical call

-DOE

Hi all, DOE is asking if we can push this call to Wednesday (tomorrow)—their CCS technical lead is having a travel snafu. Would Wednesday work for EPA? If so, please suggest some times, I have asked DOE to be flexible on timing given the ask.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 18, 2023 2:32 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Tiedeman, Jennifer <[redacted]hq.doe.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Kymn, Christine J. EOP/OMB <[redacted]omb.eop.gov>; Thomas, Amanda L. EOP/OMB <[redacted]omb.eop.gov>; Roberts, Martha G. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: EPA/DOE CAA 111 CCS - technical call

Hi all! We are rescheduling to 11am tomorrow. Since I don't own the invite, I can't take this down, so please make your colleagues aware if you've forwarded this to them previously. I will send a new invite shortly.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 18, 2023 2:37 PM
To: Miller, Sofie E. EOP/OMB; Tatham, Steph J. EOP/OMB; Thompson, Lisa; Tiedeman, Jennifer; Hutson, Nick; Gilbreath, Jan; Kymn, Christine J. EOP/OMB; Thomas, Amanda L. EOP/OMB; Roberts, Martha G. EOP/OMB
Subject: Rescheduled: EPA/DOE CAA 111 CCS - technical call
When: Wednesday, April 19, 2023 11:00 AM-12:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 18, 2023 3:08 PM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: FERC call on 4/21 - EPA 111 NPRM (2060-AV09)

Hi Lisa & Jan,

Would EPA be available on Friday 4/21 from 10-11am for the requested FERC call? I know we have an EO 12866 meeting scheduled for 10am, but if this is FERC's availability perhaps we can both find coverage.

Best,

Sofie

From: Gilbreath, Jan <[redacted]epa.gov>
Sent: Tuesday, April 18, 2023 3:25 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>
Subject: RE: FERC call on 4/21 - EPA 111 NPRM (2060-AV09)

Sofie,
I'm okay with this, but I don't know how it works with Lisa's schedule.
Jan

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Tuesday, April 18, 2023 3:33 PM
To: Gilbreath, Jan <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: FERC call on 4/21 - EPA 111 NPRM (2060-AV09)

I'm checking OAR's availability and will get back to you soon. Thanks.

From: Thompson, Lisa
Sent: Tuesday, April 18, 2023 4:59 PM
To: [redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>
Subject: CAA 111 preamble - EPA passback #2

Hi Steph and Sofie –

Attached is EPA's second preamble passback which includes the reworked sections on existing gas, the ACE repeal, and hydrogen standards for new turbines, along with additional refinements. I've also included the updated ICRs for the NSPS (TTTTa) and Emission Guidelines (UUUUb). Please let me know if you'd like these sent through ROCIS as well.

Thanks,
Lisa

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 18, 2023 9:16 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin

<[redacted]epa.gov>
Subject: RE: CAA 111 preamble - EPA passback #2

Hi Lisa,

Thanks, received. We were also expecting the reg text passback today. Is that file ready?

Best,

Sofie

From: Thompson, Lisa
Sent: Wednesday, April 19, 2023 7:37 AM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>
Subject: RE: CAA 111 preamble - EPA passback #2

Hi Sofie,

We spoke on the phone about that deliverable moving to Thursday with the TSDs. Let me circle with the team and see if we can get it to you today. Apologies for the misunderstanding.

Thanks,
Lisa

From: Miller, Sofie E. EOP/OMB
Sent: Wednesday, April 19, 2023 10:00 AM
To: 'Thompson, Lisa' <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: FERC call on 4/21 - EPA 111 NPRM (2060-AV09)

Thanks Lisa—I called over to FERC and they are looking at staff availability for Friday afternoon. I should have some times for you soon.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 19, 2023 1:04 PM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 - interagency cover comments/add'l data

Hi Lisa & Jan,

Attached is some additional data that a reviewing agency is providing as a follow-up to one of the calls last week. I checked with the agency to confirm the file does not contain any CBI.

Best,

Sofie

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 19, 2023 8:53 AM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>
Subject: RE: CAA 111 preamble - EPA passback #2

Thanks Lisa—my notes must have been incomplete from our call, I appreciate you refreshing my memory.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 19, 2023 4:11 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Garfinkle, Stacey <[redacted]epa.gov>; Marks, Matthew <[redacted]epa.gov>; Profeta, Timothy <[redacted]epa.gov>; Greenglass, Nora <[redacted]epa.gov>; Adamantiades, Mikhail <[redacted]epa.gov>; Weatherall, Grace <[redacted]epa.gov>; Huetteman, Justine <[redacted]epa.gov>
Subject: RE: WHCO/EPA CAA 111 GHG Emissions NPRM call No. 2

Hi all, the reviewer is requesting that we block more time for this call. Would you be able to extend this window to 1:30 or 2:00pm for a 90 or 120-minute call? The comments will be on both tranches 1 and 2 of EPA's preamble passback.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 19, 2023 8:50 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 preamble - EPA passback #2

Hi Lisa + team,

Attached are consolidated 2nd round interagency comments embedded in the preamble text, along with the separate document providinh recommended edits on EACs for low-GHG hydrogen that is referenced in a comment on p. 309.

We look forward to reviewing the TSD, regulatory text, and RIAs soon. I'm copying my colleague Matthew Oreska, who will be covering this rule beginning next week.

Best,

Sofie

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 19, 2023 12:14 PM
To: Miller, Sofie E. EOP/OMB; Hutson, Nick; Gilbreath, Jan; Culligan, Kevin; Thompson, Lisa

Subject: CONFIRMED - RIA passback briefing for EPA CAA 111 GHG Emissions NPRM (2060-AV09)
When: Friday, April 21, 2023 2:00 PM-3:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 9:33 AM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: Availability for call on Friday 4/21

Hi Lisa & Jan,

DOJ is available from 12-1pm, or, if EPA can do 1-2, that would also work. They don't have a lot of openings before 1pm unfortunately.

From: Gilbreath, Jan <[redacted]epa.gov>
Sent: Thursday, April 20, 2023 9:37 AM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Availability for call on Friday 4/21

Sofie,
The RIA call is at 2 pm. Does it make sense to try for 12-1 pm to avoid conflict? But I defer to Lisa, who has to corral the appropriate OAR people for the call.
Jan

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 9:41 AM
To: Gilbreath, Jan <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: Availability for call on Friday 4/21

12-1 works for OAR and OGC as well. Thanks!

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 9:54 AM
To: Miller, Sofie E. EOP/OMB; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Garfinkle, Stacey; Marks, Matthew; Profeta, Timothy; Greenglass, Nora; Adamantiades, Mikhail; Weatherall, Grace; Huetteman, Justine
Subject: DOJ/EPA CAA 111 GHG Emissions NPRM call No. 3
When: Friday, April 21, 2023 12:00 PM-1:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 11:58 AM
To: [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs - TSDs and Reg Text - passback #3

Hi Steph, Sofie, and Matthew,

Attached are revised versions of the TSDs and Reg Text. 20 documents are in the attached zip file, clean and redline versions of the following files:

1. Reg Text - Proposed TTTT
2. Reg Text - Proposed TTTTa
3. Reg Text - Proposed UUUUb
4. TSD - GHG Mitigation Measures - 111(b)
5. TSD - GHG Mitigation Measures - 111(d)
6. TSD - Natural Gas And Oil Steam EGUs
7. TSD - Power Sector Trends
8. TSD - Resource Adequacy & Reliability Assessment
9. TSD - Hydrogen in Combustion Turbine EGUs
10. TSD - Efficient Generation Combustion Turbine EGUs

Please let me know if you have any questions.
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 12:45 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

Hi Lisa,

I can’t receive ZIP files, can you send the individual files in separate emails? Sorry for the hassle. I can also create a MAX page for upload if you’d prefer but think email will be quicker.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 1:32 PM
To: Thompson, Lisa <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: FERC call on 4/21 - EPA 111 NPRM (2060-AV09)

Hi Lisa,

Would 1:30 on Friday work for EPA for this staff discussion?

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 1:51 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: FERC call on 4/21 - EPA 111 NPRM (2060-AV09)

Yes, thank you!

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 2:16 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

Apologies I didn't see this note during our last call. I'm attaching the files in batches.

1. Reg Text - Proposed TTTT
2. Reg Text - Proposed TTTTa
3. Reg Text - Proposed UUUUb

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 2:17 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

1. TSD - GHG Mitigation Measures - 111(b)
2. TSD - GHG Mitigation Measures - 111(d)
3. TSD - Natural Gas And Oil Steam EGUs

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 2:19 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

1. TSD - Power Sector Trends
2. TSD - Resource Adequacy & Reliability Assessment
3. TSD - Hydrogen in Combustion Turbine EGUs
4. TSD - Efficient Generation Combustion Turbine EGUs

From: Thompson, Lisa
Sent: Thursday, April 20, 2023 2:20 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

Hi Sofie,

Apologies again for the delay. Can you confirm you received all 20 files sent in 3 batches? Please let me know if you're missing anything.

Lisa

From: Miller, Sofie E. EOP/OMB
Sent: Thursday, April 20, 2023 2:25 PM
To: 'Thompson, Lisa' <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

Hi Lisa,

Yes, received! Thanks for re-sending.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 10:17 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

Hi Lisa & team,

Relaying a question from an interagency reviewer—is there going to be a new TSD supporting CCS as BSER for existing gas plants that meet the capacity factor and size criteria? Or, if this is covered already in an existing TSD, can you point us to the right place?

Thank you!

Sofie

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 1:54 PM
To: Miller, Sofie E. EOP/OMB; Oreska, Matthew P. EOP/OMB; Carolyn Templeton; Ellen Brown; InformFERC; Hutson, Nick; Culligan, Kevin; Gilbreath, Jan; Thompson, Lisa
Subject: FERC-EPA call on EPA 111 GHG Emissions NPRM
When: Friday, April 21, 2023 1:30 PM-2:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 20, 2023 5:26 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: follow-up

Hi Lisa, I checked and it doesn't sound like that call took place so I have no readout for you—I think we are good with the list of topics we previously discussed, any anything else you think merits discussion.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 21, 2023 10:07 AM
To: Thompson, Lisa; Hutson, Nick; Gilbreath, Jan; Garfinkle, Stacey; Marks, Matthew; Profeta, Timothy; Greenglass, Nora; Adamantiades, Mikhail; Weatherall, Grace; Huetteman, Justine
Subject: OMB OGC/EPA CAA 111 GHG Emissions NPRM call No. 2
When: Friday, April 21, 2023 11:30 AM-12:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Thompson, Lisa
Sent: Friday, April 21, 2023 10:56 AM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text - passback #3

Hi Sofie –

There won't be a new TSD developed. Technical support can be found in the GHG mitigation measures TSDs and additional analysis is found in the RIA which we'll be sending shortly.

Thanks,
Lisa

From: Thompson, Lisa
Sent: Friday, April 21, 2023 12:09 PM
To: [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs - RIA - passback #4

Hi Steph, Sofie, and Matthew,

Please find attached the update RIA in clean and redline. Please let me know if you have any questions.

Please note that there is text in several sections of the RIA that mirrors preamble text, which will be updated to match the final preamble that clears OMB. We've added comments to flag each of those sections in the redline version attached.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 21, 2023 12:23 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RIA?

Did you send this? I am wondering if my inbox is lagging

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Friday, April 21, 2023 12:25 PM
To: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: RIA?

Yes, sent right after noon when my computer rebooted. Let me resend one at a time just in case?

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 21, 2023 12:25 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Thank you! Received.

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 21, 2023 12:26 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: RIA?

OBE! Our emails just crossed paths, I got it

From: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 21, 2023 3:45 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 preamble - EPA passback #2

Hi Lisa & team,

Attached are consolidated 2nd round interagency comments on EPA's 2nd tranche preamble passback. In addition to the embedded preamble comments/edits, you'll see two additional files provided by an interagency reviewer related to heat rate improvements and sources.

The RIA, regulatory text, and TSDs are out for comment and we expect to get you passback on those documents early Tuesday.

Happy Friday!

Sofie

From: Thompson, Lisa
Sent: Friday, April 21, 2023 4:25 PM
To: [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: 111 CAA EGUs - subsidies

Hi Sofie,

For text on subsides, please refer reviewers to sections 0.5; 0.9; 3.5; 5.2; 7.1; and 7.3 of the RIA, as well as sections: 10.3.2; 10.4.1; 10.5 of Appendix B: Economy-wide Social Costs and Economic Impacts

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards

U.S. Environmental Protection Agency
[redacted]

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 24, 2023 9:36 AM
To: Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Good morning, Lisa,

Please find attached a few comments from reviewers on the TSD.

Thank you,

Matthew

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 24, 2023 7:53 PM
To: Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Hi Lisa,

Just circling back to confirm that I am still receiving a few comments on the RIA, so I will likely send the consolidated passback early tomorrow.

Thanks,

Matthew

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Monday, April 24, 2023 7:54 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

We are continuing to work on the preamble, but will have a passback later this evening.

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, April 24, 2023 8:57 PM

To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Good evening, Kevin,

I recognize that EPA is in the process of finalizing the 2nd-round preamble passback, but I received some late 2nd-round interagency comments on the preamble that reviewers would like EPA to incorporate in the passback, if at all possible (attached). These new comments are provided on a clean version of the first-round preamble passback document and labeled New Comment 4/24. I also received an attached memo from a reviewer providing additional information on an earlier comment for EPA's consideration.

Thank you,

Matthew

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Monday, April 24, 2023 9:02 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Matt,

Only way we can incorporate the comments is if the passback slips to tomorrow AM. If you want it tonight, I don't see how we can address more comments in this passback.

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Monday, April 24, 2023 10:00 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Note that we already have some of the concepts in the passback we are sending back tonight. We will review the rest tomorrow.

From: Thompson, Lisa
Sent: Monday, April 24, 2023 11:14 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan

<[redacted]epa.gov>
Subject: CAA 111 EGUs preamble - EPA Passback

Hi Matthew, Steph, and Sofie –

Please find attached EPA's latest preamble passback, both clean and in redline (compared against the 4/18 passback). Note that this does not address the late 2nd round interagency comments sent this evening.

Please let me know if you have any questions.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 25, 2023 8:56 AM
To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Thanks, Kevin. Understood.

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 25, 2023 4:02 PM
To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Good afternoon,

Please find attached consolidated interagency comments on the RIA passback (attached). We're still working to consolidate comments on the TSD pieces.

Following up on my conversation with Lisa regarding the preamble passback, we'll look for a single passback by noon tomorrow.

Thanks,

Matthew

From: Thompson, Lisa
Sent: Tuesday, April 25, 2023 4:14 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Received. Thanks Matthew!

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, April 25, 2023 6:49 PM
To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4

Good evening,

Please find attached consolidated comments on the TSDs and two comments on the Reg Text. EPA should now have all outstanding comments from this round of review.

Thank you,

Matthew

From: Thompson, Lisa
Sent: Wednesday, April 26, 2023 7:43 AM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble - EPA Passback

Hi Matthew –

Please find the updated passback attached, in clean and in redline. The redline is compared against the 4/18 passback. We've also included two files with responses to the second round of interagency comments, one the first tranche and one that addresses the late comments. Note that because we generated a new file before addressing the late comments, the version "clean with comment responses" does not include the most recent text updates. Reviewers should only look to that for specific comment responses, but rely on the other three files for the most up-to-date preamble text.

Thanks,
Lisa

From: Thompson, Lisa
Sent: Wednesday, April 26, 2023 7:44 AM

To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: Preamble

Can you confirm you received the preamble passback this morning?

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 26, 2023 7:48 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: Re: Preamble

Hi Lisa,

It doesn't look like I received it. Can you resend?

Thanks,

Matthew

Sent from my iPhone

From: Thompson, Lisa
Sent: Wednesday, April 26, 2023 7:55 AM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble - EPA Passback

From: Thompson, Lisa
Sent: Wednesday, April 26, 2023 7:55 AM
To: 'Oreska, Matthew P. EOP/OMB' <[redacted]omb.eop.gov>; '[redacted]omb.eop.gov' <[redacted]omb.eop.gov>; '[redacted]omb.eop.gov' <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble - EPA Passback

Sending in two emails since looks like the first one didn't go through.

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Wednesday, April 26, 2023 7:55 AM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: Preamble

Just resent! Let me know in a few minutes if you get it or not?

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 26, 2023 7:58 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Preamble

Thanks, Lisa. Just received your email with all the attachments and two with two apiece. I see what appear to be four unique docs.

Thanks for sending!

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Wednesday, April 26, 2023 7:59 AM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: Preamble

Confirming 4 unique docs. Thank you!!

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 26, 2023 8:02 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Preamble

Many thanks!

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, April 26, 2023 8:22 PM
To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4 (2060-AV09 and 2060-AV10)

Good evening,

Two reviewers have inquired about scheduling a call with EPA to discuss the passback. Schedules are complicated tomorrow, but it looks like 2:30-3:30 would work on this side. Does that window work for EPA?

Thanks,

Matthew

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Wednesday, April 26, 2023 10:09 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>

Cc: Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: Re: CAA 111 EGUs - RIA - passback #4 (2060-AV09 and 2060-AV10)

Can you give us an idea of the topics so that we can have the right people there? Also, aren't we supposed to be making the passbook as close to noon as possible? My understanding is that is what Martha requested of Tomas.

Sent from my iPhone

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 27, 2023 8:31 AM
To: Culligan, Kevin <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4 (2060-AV09 and 2060-AV10)

Hi Kevin, Lisa and I spoke briefly this morning. She can provide details. Look for a calendar invite momentarily….

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 27, 2023 8:35 AM
To: Oreska, Matthew P. EOP/OMB; Culligan, Kevin; Thompson, Lisa; Hutson, Nick; Gilbreath, Jan
Cc: Miller, Sofie E. EOP/OMB; Tatham, Steph J. EOP/OMB; Greenglass, Nora; Huetteman, Justine; Keaveny, Brian; Weatherhead, Darryl (she/her/hers); Greenfield, Meghan; Carbonell, Tomas; Profeta, Timothy; Garfinkle, Stacey; Weatherall, Grace
Subject: Comments on 111 (2060-AV09; 2060-AV10)
When: Thursday, April 27, 2023 3:00 PM-4:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

Two reviewers would like to discuss the passback with EPA.

Adjusting the start time. Note that I have not yet received confirmation from the other participants that they can extend from 3:30-4:00. We may have to stop at 3:30 and schedule a part II.

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Thursday, April 27, 2023 9:25 AM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Culligan, Kevin <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4 (2060-AV09 and 2060-AV10)

Hi Matthew,

EPA can do 3:00-4:00. Let us know if that works, or if we need to shorten to 3:00-3:30.

Lisa

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 27, 2023 9:54 AM
To: Thompson, Lisa <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>
Cc: Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA - passback #4 (2060-AV09 and 2060-AV10)

Hi Lisa,

Understood. I'm checking with reviewers on flexibility, given what appear to be schedule conflicts from 3:30 to 4:00. We'll go with the shorter call if need be.

Thanks,

Matthew

From: Thompson, Lisa
Sent: Thursday, April 27, 2023 11:54 AM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs - EPA Passback -- RIA

Hi Matthew,

Please find attached the RIA passback. We've included a clean and redline version, along with a separate file contains EPA's responses in comment bubbles. This is different than the RLSO version, as not all edits are reflected in the text of this file. To see all edits made in response to interagency comments, please see the Clean and RLSO versions. In addition, we've included an excel file of unrounded health benefit estimates that was requested by interagency commenters.

Please let me know if you have any questions.
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Thompson, Lisa
Sent: Thursday, April 27, 2023 12:00 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>;

[redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs - EPA Passback -- TSDs

Hi Matthew,

Please find attached the TSD passback. This includes the following TSDs, clean and in redline (10 files total):

1. TSD – GHG Mitigation Measures – Carbon Capture and Storage for Combustion Turbines (formerly GHG Mitigation Measures - 111(b))
2. TSD – GHG Mitigation Measures for Steam Generating Units (formerly GHG Mitigation Measures - 111(d))
3. TSD - Power Sector Trends
4. TSD – Resource Adequacy Analysis (formerly Resource Adequacy & Reliability Assessment)
5. TSD - Hydrogen in Combustion Turbine EGUs

Please let me know if you have any questions.
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Thompson, Lisa
Sent: Thursday, April 27, 2023 12:20 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: Confirming you received the RIA and TSDs?

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 27, 2023 12:21 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - EPA Passback -- TSDs

Thank you, Lisa. Received. -Matthew

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 27, 2023 12:39 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - EPA Passback -- TSDs

Lisa, is EPA planning to send a passback confirming any changes in response to the two Reg Text comments?

From: Thompson, Lisa
Sent: Thursday, April 27, 2023 12:45 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - EPA Passback -- TSDs

Yes, those files are coming momentarily. We were just finalizing the addition of third phase to the TTTTa reg text – apologies for the delay.

From: Thompson, Lisa
Sent: Thursday, April 27, 2023 12:48 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: CAA 111 EGUs - EPA Passback -- Reg Text

Hi Matthew,

Please find attached the Reg Text passback. This includes the proposed subparts TTTT, TTTTa, and UUUUb, clean and in redline (6 files total). Please let me know if you have any questions.

Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, April 27, 2023 6:03 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan

<[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - EPA Passback -- TSDs

Hi Lisa and team,

The latest consolidated interagency comments on the preamble are attached. I'm not aware of any outstanding preamble comments at this round.

Thanks,

Matthew

From: Thompson, Lisa
Sent: Thursday, April 27, 2023 7:20 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - EPA Passback -- TSDs

Received – thanks Matthew.

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, April 28, 2023 3:54 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - EPA Passback -- TSDs

Good afternoon, Lisa,

Please find attached consolidated interagency comments on the RIA, the Reg Text, and on the TSDs. Reviewers only had comments on three of the TSD pieces (attached).

Several reviewers observed that the requests for comment in the RIA do not sufficiently cover all aspects of the analysis and its assumptions. As an alternative to adding multiple, additional requests for comment, reviewers suggest including a general request for comment on Preamble p. 624, as noted in the attached Preamble document. Note that the interagency Preamble comments provided yesterday remain active comments, even though they are not reiterated in the attached version of the Preamble.

Finally, it would be helpful if EPA can hold time on Monday morning, just in case there is a need for further discussion with any of the reviewers. Steph will be back Monday, so please continue to cc her on correspondence. She will likely close out this review.

Thank you,

Matthew

From: Thompson, Lisa
Sent: Friday, April 28, 2023 8:53 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs preamble -- EPA passback

Hi Matthew, Steph, and Sofie –

Please find attached EPA's latest preamble passback, both in clean and in redline (compared against the 4/26 version). This addresses the third round of comments sent yesterday, and the additional preamble comment sent this afternoon.

Don't hesitate to reach out if you have any questions.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Sent: Sunday, April 30, 2023 1:36 PM
To: Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Thank you, Lisa

Best,

Matthew

From: Thompson, Lisa
Sent: Monday, May 1, 2023 11:31 AM
To: [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs - TSDs and Reg Text

Hi Steph –

Please find attached EPA's responses to the latest set of interagency comments from 4/28.

- Reg Text - Proposed TTTT
- Reg Text - Proposed TTTTa
- TSD – GHG Mitigation Measures – Carbon Capture and Storage for Combustion Turbines
- TSD – Hydrogen in Combustion Turbine EGUs
- TSD – Resource Adequacy Analysis

Note that our responses to the RIA comments will be sent shortly.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:32 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: Just sent the TSDs and Reg text

Can you confirm you received all 10 files?

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 11:42 AM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: RE: Just sent the TSDs and Reg text

None yet :/ you can try drive.max.gov if they're too big.

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:48 AM
To: [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Sending a few at a time to try to make sure you get them.

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:49 AM
To: Thompson, Lisa <[redacted]epa.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Reg Text - Proposed TTTTa

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 11:49 AM
To: Hutson, Nick <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Reg text received TTTT only.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 11:49 AM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Received.

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:49 AM
To: Thompson, Lisa <[redacted]epa.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

TSD – Hydrogen in Combustion Turbine EGUs

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 11:50 AM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Received

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:50 AM
To: Thompson, Lisa <[redacted]epa.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

- TSD – Resource Adequacy Analysis

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC

Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:50 AM
To: Thompson, Lisa <[redacted]epa.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

TSD – GHG Mitigation Measures – Carbon Capture and Storage for Combustion Turbines

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 11:51 AM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Received.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 11:51 AM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Miller, Sofie E. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - TSDs and Reg Text

Received

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 11:53 AM
To: Thompson, Lisa <[redacted]epa.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: CAA 111 EGUs - RIA

Steph,

Attached is the RIA passback for the 111 EGU rules.

This includes our response to interagency comments in a RLSO version, and also a clean version.

Nick

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - Office of Air Quality Planning and Standards
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 12:04 PM
To: Thompson, Lisa <[redacted]epa.gov>; [redacted]omb.eop.gov; [redacted]omb.eop.gov; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Steph,

I believe we have now provided all of the passback documents that you were expecting.

Please confirm receipt (… I've gotten receipt notices for

TTTT reg text
TTTTa reg text
Hydrogen TSD
Resource Adequacy TSD
GHG Mitigation Measures TSD

So, I think we just need confirmation of receipt of the RIA. If you haven't gotten it, then I'll try to send clean and RLSO separately.

Nick

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - *Office of Air Quality Planning and Standards*
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 12:12 PM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

No RIA yet, sorry. Thanks! Also, dropping Sofie.

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 12:18 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Clean RIA

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - *Office of Air Quality Planning and Standards*
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 12:19 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

RLSO RIA

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - *Office of Air Quality Planning and Standards*
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Hutson, Nick <[redacted]epa.gov>
Sent: Monday, May 1, 2023 12:20 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Ok … I just tried sending clean and RLSO separately. If that doesn't work, we'll need to try drive.max.gov.

Nick Hutson, PhD
Group Leader – Energy Strategies Group
U.S. EPA - *Office of Air Quality Planning and Standards*
Research Triangle Park, NC
Email: [redacted]epa.gov
Tel: [redacted]
Mobile: [redacted]
About the Sector Policies and Programs Division (SPPD) | US EPA

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 12:22 PM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian

<[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Clean received, thanks

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 12:22 PM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

RLSO received, thanks

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 1:19 PM
To: Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Just circling to say that we do have comments but I'm holding for a final reviewer. Thanks.
Steph

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 3:14 PM
To: Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

-Sofie,
Please find inter-agency reviewer comments attached. Thanks!
Steph

From: Thompson, Lisa
Sent: Monday, May 1, 2023 3:18 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Received. Can you confirm you are not sending additional RIA comments?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 3:29 PM
To: Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

I cannot. We will have a few, they are relatively minor. Still waiting on one more reviewer.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 4:04 PM
To: Hutson, Nick <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Please find RIA comments attached, nothing from us on the TSDs.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 4:06 PM
To: Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Ok, just sent comments on the RIA. Nothing from us on the reg. text.
So, we're willing to conclude tonight if necessary but note that it would require folks from OP to be available for posting. If EPA wants us to go that route we need to have everything back by 7pm for a final look. Our preference would be to receive revised drafts by 5pm and I can give you the go ahead by 5:30pm to load into ROCIS for conclusion by 6pm provided everything looks good. We could also conclude first thing in the morning if OP is not available tonight but this timeline doesn't work.
Thanks,
Steph

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Monday, May 1, 2023 4:30 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>

Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

We will work with Jan and the OP team. Key for us is having a package we can move forward to the administrator for signature tonight and having formal clearance before the administrator signs. Either plan outlined below seems to accomplish that.

From: Gilbreath, Jan <[redacted]epa.gov>
Sent: Monday, May 1, 2023 4:36 PM
To: Culligan, Kevin <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Maignan, Tawanda <[redacted]epa.gov>; Nickerson, William <[redacted]epa.gov>; Muellerleile, Caryn <[redacted]epa.gov>; Curry, Bridgid <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Okay, I can work late and do my part, but I don't have access to ROCIS, so I will need to check if someone from RMD can be available. Give me a few minutes to determine this. Do we know how long until final upload into ROCIS?

Jan

From: Gilbreath, Jan <[redacted]epa.gov>
Sent: Monday, May 1, 2023 4:40 PM
To: Culligan, Kevin <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Okay, RMD can handle the upload tonight.

Jan

From: Thompson, Lisa
Sent: Monday, May 1, 2023 6:23 PM
To: [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: CAA 111 EGUs - RIA

Hi Steph –

Please find attached our responses to the latest RIA comments. Clean file attached.

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Thompson, Lisa
Sent: Monday, May 1, 2023 6:24 PM
To: [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Redline version attached.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 7:02 PM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Keaveny, Brian <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - RIA

Thanks Lisa and team,
We are good on the RIA. I'm going to open ROCIS so you can start uploading the clean TSDs and RIA. Please hold on the preamble until we sign off. If you prefer to wait and handle all at once that's fine with us.
Steph

From: Thompson, Lisa
Sent: Monday, May 1, 2023 6:59 PM
To: [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: CAA 111 EGUs - Preamble

Hi Steph –

Please find attached our responses to the latest preamble comments. Redline file attached here.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards

U.S. Environmental Protection Agency
[redacted]

From: Thompson, Lisa
Sent: Monday, May 1, 2023 7:02 PM
To: '[redacted]omb.eop.gov' <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Clean file attached.

Also, note there we had some major formatting issues with this last version that we are continuing to resolve.

Thanks,
Lisa

From: Thompson, Lisa
Sent: Monday, May 1, 2023 7:05 PM
To: [redacted]omb.eop.gov
Subject: FW: CAA 111 EGUs - Preamble

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 7:08 PM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Still no redline, unfortunately. Can you please try to send me a PDF?

From: Thompson, Lisa
Sent: Monday, May 1, 2023 7:13 PM
To: [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

One more try to send the redline.

From: Thompson, Lisa
Sent: Monday, May 1, 2023 7:14 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Just tried one more time. The PDF is taking a while to generate, but I'll sent shortly.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 7:15 PM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Hi Lisa,
I think we're also going to have issues with EPA keeping the price information from the Rhodium report on pp. 369-370. Given typos, I am hopeful EPA accepted this change but there's just an issue in the clean. Can you please confirm?
Thanks,
Steph

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Monday, May 1, 2023 7:16 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

I thought we took it out.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 7:22 PM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: Re: CAA 111 EGUs - Preamble

Finally!

From: Thompson, Lisa
Sent: Monday, May 1, 2023 7:22 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: CAA 111 EGUs - Preamble

Great – the PDF was taking forever!

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 7:29 PM
To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

I still see it in the clean and redline, unfortunately. Maybe just a version control issue. Is there a comment response for the "worker engagement" language? I can set up a call for this morning if that's easiest.

In any event, I think we can't conclude tonight given the live issue so I'm happy to pick this up in the morning.
Thanks,
Steph

From: Muellerleile, Caryn <Muellerleile.Caryn@epa.gov>
Sent: Monday, May 1, 2023 7:42 PM
To: Gilbreath, Jan <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Hello all,

Is there still a desire for clearance this evening, or is it being pushed to morning?

Caryn

From: Thompson, Lisa
Sent: Monday, May 1, 2023 7:43 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Culligan, Kevin <[redacted]epa.gov>
Cc: Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Thank you Steph. Can you set up a call for tomorrow morning?

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Monday, May 1, 2023 7:43 PM
To: Muellerleile, Caryn <Muellerleile.Caryn@epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Tomorrow.   Sorry for everyone who worked late Friday and today to try to make it happen today.

From: Gilbreath, Jan <[redacted]epa.gov>
Sent: Monday, May 1, 2023 8:58 PM
To: Muellerleile, Caryn <Muellerleile.Caryn@epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>; Oreska, Matthew P. EOP/OMB <[redacted]omb.eop.gov>
Cc: Hutson, Nick <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs preamble -- EPA passback

Caryn,
Looks like we need another call with OMB tomorrow morning.

Jan

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Monday, May 1, 2023 8:46 PM
To: Tatham, Steph J. EOP/OMB; Thompson, Lisa; Hutson, Nick; Culligan, Kevin; Gilbreath, Jan
Subject: EPA/EOP CAA 111 GHGs call
When: Tuesday, May 2, 2023 10:00 AM-10:30 AM (UTC-05:00) Eastern Time (US & Canada).
Where: zoomgov

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Tuesday, May 2, 2023 8:35 AM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB
<[redacted]omb.eop.gov>
Subject: Is the 10:00 just about employment or employment or hydrogen?

We are good taking out the cost numbers. I agree that they were not taken out in the version you got.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, May 2, 2023 9:04 AM
To: Culligan, Kevin <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: Re: Is the 10:00 just about employment or employment or hydrogen?

Employment, can you please make sure Tomás Carbonell and Susannah Weaver are invited? Thanks!

From: Thompson, Lisa
Sent: Tuesday, May 2, 2023 9:05 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Culligan, Kevin
<[redacted]epa.gov>
Subject: RE: Is the 10:00 just about employment or employment or hydrogen?

Thank you Steph. Confirming they are invited.

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Tuesday, May 2, 2023 9:25 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Is the 10:00 just about employment or employment or hydrogen?

Tomas, Susannah and Joe will all be attending. We will also have career legal and technical staff.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, May 2, 2023 9:40 AM
To: Culligan, Kevin <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Is the 10:00 just about employment or employment or hydrogen?

Great, thanks. We'll have Karen Anderson from CPO, Martha Roberts for OIRA, and Megan Ceronsky for WHCO.

From: Thompson, Lisa
Sent: Tuesday, May 2, 2023 10:19 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: EPA/EOP CAA 111 GHGs call

The EPA also acknowledges that employment at affected EGUs (including employment in operation and maintenance as well as in construction for installation of pollution control technology) is impacted by power sector trends on an ongoing basis, and states may choose to take energy communities into consideration as part of meaningful engagement. A variety of federal programs are available to support these communities.[1]

FN1 -- An April 2023 report of the federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) summarizes how the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act have greatly increased the amount of federal funding relevant to meeting the needs of energy communities, as well as how the Energy Communities IWG has launched an online Clearinghouse of broadly available federal funding opportunities relevant for meeting the needs and interests of energy communities, with information on how energy communities can access federal dollars and obtain technical assistance to make sure these new funds can connect to local projects in their communities. Interagency Working Group on Coal and

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[1] An April 2023 report of the federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) summarizes how the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act have greatly increased the amount of federal funding relevant to meeting the needs of energy communities, as well as how the Energy Communities IWG has launched an online Clearinghouse of broadly available federal funding opportunities relevant for meeting the needs and interests of energy communities, with information on how energy communities can access federal dollars and obtain technical assistance to make sure these new funds can connect to local projects in their communities. Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization. "Revitalizing Energy Communities: Two-Year Report to the President" (April 2023). https://energycommunities.gov/wp-content/uploads/2023/04/IWG-Two-Year-Report-to-the-President.pdf.

Power Plant Communities and Economic Revitalization. "Revitalizing Energy Communities: Two-Year Report to the President" (April 2023). *https://energycommunities.gov/wp-content/uploads/2023/04/IWG-Two-Year-Report-to-the-President.pdf*.

From: Thompson, Lisa
Sent: Tuesday, May 2, 2023 10:49 AM
To: [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Hi Steph,

Resending the preamble with the formatting and hydrogen issues fixed. Sending redline only so you can see the changes.

Thanks,
Lisa

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, May 2, 2023 11:13 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: Not yet

Were you calling about 12866 or something else?

Steph Tatham
OIRA Policy Analyst
[redacted]

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Tuesday, May 2, 2023 11:14 AM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Subject: RE: Not yet

Wanted to alert you to the connection issues on the call. I can try sending through max – can you send me the link?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, May 2, 2023 11:15 AM
To: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Not yet

Thank you! And yep, here you go: [redacted]
Thanks!

From: Thompson, Lisa
Sent: Tuesday, May 2, 2023 11:34 AM
To: [redacted]omb.eop.gov
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Also sent this via OMB Max: [redacted]

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, May 2, 2023 11:41 AM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Received via MAX

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Tuesday, May 2, 2023 2:22 PM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Hi Lisa and team,

Folks here have flagged two issues in the latest redline:

1) The EPA is soliciting comment on requiring EGUs to use geographic and temporal alignment approaches for EAC-related requirements and the appropriate timing and trade-offs of such approaches.
   Suggestion in prior comments: The EPA is soliciting comment on requiring EGUs to use geographic and temporal alignment approaches and additionality for EAC-related requirements and the appropriate timing and trade-offs of such approaches.

2) Footnote 514: April 12, 2023, memorandum, “How annual matching for the Inflation Reduction Act’s (IRA) 45V clean hydrogen tax credit can accelerate progress towards the Biden administration’s decarbonization and clean hydrogen goals” signed by 23 companies, addressed to Treasury Secretary Janet Yellen, Energy Secretary Jennifer Granholm and Senior Advisor to the President for Clean Energy Innovation and Implementation ~~Senior Advisor to the President for Clean Energy Innovation and Implementation~~ Mr. John Podesta, indicated an openness to examine hourly EAC requirements in 2032 or earlier and asserted, “recent studies warn that overly stringent temporal matching would hinder the development of clean hydrogen industry.”

I’m in a SBREFA panel but will call when it’s over. Please let me know if a call is needed on 1. 2 is take or leave.

Thanks,

Steph

From: Thompson, Lisa
Sent: Tuesday, May 2, 2023 2:31 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Thank you Steph. 2 is a typo and we'll make this change. I'll let you know soon if we need a call on 1.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Wednesday, May 3, 2023 9:57 AM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Hi Lisa,
On the request to take comment on additionality, would it help EPA to accept this request to add a sentence along the lines of the following:
"EPA notes that additionality requirements are likely to have less relevance when implemented in the context of greenhouse gas emission standards for EGUs."
Thanks for considering it,
Steph

From: Thompson, Lisa
Sent: Wednesday, May 3, 2023 2:28 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Steph,

As discussed, I've uploaded the clean file which addresses #2 below. We've also changed the public hearing dates from 14 days to 21 days following publication.

[redacted]

Thanks,
Lisa

From: Thompson, Lisa <[redacted]epa.gov>
Sent: Thursday, May 04, 2023 12:21 PM
To: [redacted]omb.eop.gov
Cc: King, Melanie (she/her/hers) <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>;

Hutson, Nick <[redacted]epa.gov>
Subject: EPA contact this afternoon

Hi Steph,

Nick and I are both out of the office this afternoon, so please include Melanie King (cc'd) and Kevin on any further updates. I'll be back in the office tomorrow.

Thanks,
Lisa

Lisa Thompson (she/her)
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
[redacted]

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Thursday, May 4, 2023 12:22 PM
To: Thompson, Lisa <[redacted]epa.gov>; Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Cc: King, Melanie (she/her/hers) <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: RE: EPA contact this afternoon

Thanks Lisa – people above us are very anxious to hear about where we are.   Anything I can say?

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, May 04, 2023 1:23 PM
To: Culligan, Kevin <[redacted]epa.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: King, Melanie (she/her/hers) <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: RE: EPA contact this afternoon

Thanks so much, on this side I'm told the EPA Administrator and CPO are coordinating and will let our Administrator know timing. Unfortunately, I don't have any further specifics.
Steph

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Thursday, May 4, 2023 1:31 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>; Thompson, Lisa <[redacted]epa.gov>
Cc: King, Melanie (she/her/hers) <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>
Subject: RE: EPA contact this afternoon

That is great.

From: Culligan, Kevin <[redacted]epa.gov>
Sent: Thursday, May 4, 2023 3:53 PM
To: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>

Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: Do you have any sense for whether there is a window around any potential clearance tonight?

Trying to figure out if there is a point at which we should assume if we haven't heard anything, it is not clearing tonight. Want to figure out whether we need to have staff on call to move it through to you. We'll need at least one person in both OAR and OP.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Thursday, May 4, 2023 4:05 PM
To: Culligan, Kevin <[redacted]epa.gov>
Cc: Thompson, Lisa <[redacted]epa.gov>
Subject: RE: Do you have any sense for whether there is a window around any potential clearance tonight?

5pm. I told them a need at least one hour notice and after 6 is the same as tomorrow from a ROCIS perspective.

From: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, May 5, 2023 1:01 PM
To: Thompson, Lisa <[redacted]epa.gov>
Cc: Culligan, Kevin <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>
Subject: RE: CAA 111 EGUs - Preamble

Hi Lisa and team,
You've probably all heard from Lisa, but just confirming in writing that ROCIS is open for amendment – thanks!

From: Thompson, Lisa
Sent: Friday, May 5, 2023 1:37 PM
To: [redacted]omb.eop.gov
Subject: FW: 111 ROCIS Upload Complete

FYI – ROCIS upload complete.

rom: Tatham, Steph J. EOP/OMB <[redacted]omb.eop.gov>
Sent: Friday, May 5, 2023 2:48 PM
To: Thompson, Lisa <[redacted]epa.gov>; Hutson, Nick <[redacted]epa.gov>; Culligan, Kevin <[redacted]epa.gov>; Gilbreath, Jan <[redacted]epa.gov>; Marks, Caryn L. EOP/OMB <[redacted]omb.eop.gov>
Subject: CAA 111 GHGs NPRM

We have concluded our review. Many thanks to EPA for their hard work.
Steph

Steph Tatham
OIRA Policy Analyst

[redacted]

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

APPLICABILITY

§60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit and integrated gasification combined cycle facility (IGCC) that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**], or commence reconstruction after June 18, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**]. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that commenced construction after January 8, 2014 or commenced modification or reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction after June 18, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER** or commence reconstruction after June 18, 2014 but before [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**] that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (9) of this section.

(1) Your EGU is a steam generating unit or IGCC that annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-

electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.*, not connected to a natural gas pipeline).

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

EMISSION STANDARDS

§60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§60.5520 What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in Table 2 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

GENERAL COMPLIANCE REQUIREMENTS

§60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under §60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 or 2 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with §60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under §60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2\ emissions\ standard\ = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in §72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in §72.2 of this chapter) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under §75.64(a) of this chapter has passed prior to October 23, 2015, emissions reporting shall begin according to §60.5555(c)(3)(i) (for Acid Rain program units), or according to §60.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under §75.64(a) of this chapter occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under §60.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580) after the calendar month in which emissions reporting is required to begin under §60.5555(c)(3)(iii).

MONITORING AND COMPLIANCE DETERMINATION PROCEDURES

§60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under §60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under §60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in §75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see §60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to §75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.*, carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with §75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to §75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from §75.11(b) or submit a petition to the Administrator under §75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for “valid operating hours”, as defined in §60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in §60.5520(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in §60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under §60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under §98.33(a)(3) of this chapter.

(d) Consistent with §60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and

operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see §60.17). For a combined heat and power (CHP) EGU, as defined in §60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.*, lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under §60.5520(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under §60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under §98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of part 98 of this chapter. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to part 75 of this chapter.

(e) Consistent with §60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in Table 1 or 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as "stack operating hours" (as defined in

§72.2 of this chapter). If you attain compliance with the applicable emissions standard in §60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternate, or if the EGUs are subject to different emission standards in Table 1 or 2 of this subpart, you must either (1) monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or (2) apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§60.13(g) and 60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the "stack operating time" (as defined in §72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with §60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in §60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under §60.5535(b) or (c), as applicable, and either the generating load data from §60.5535(d)(1) for output-based calculations or the heat input data from §60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.*, operating hours for which:

(i) "Valid data" (as defined in §60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input;

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable; or

'(iv) Grace periods for delaying RATAs for any of the parameters used to determine the hourly carbon dioxide mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from §60.5535 for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with §60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with §60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in §60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg ((lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based

standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with §60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under §60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with §60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 or 2 of this part, or the emissions standard calculated in accordance with §60.5525(a)(2).

NOTIFICATION, REPORTS, AND RECORDS

§60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 of this subpart).

(b) You must prepare and submit notifications specified in §75.61 of this chapter, as applicable, to your affected EGUs.

§60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by §60.5525 to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the

affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in §60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.*, the total number of valid operating hours (as defined in §60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with §60.5520, the CO_2 emissions standard (as identified in Table 1 or 2 of this part) with which your affected EGU must comply; and

(vi) Consistent with §60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with §60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a) of this chapter, *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under §75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under §75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with §75.4(j) of this chapter, §75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in §60.5540(a)(1)), and shall not be used in the compliance determinations under §60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under §72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under §72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under §72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in §60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under §75.53(g) and (h) of this chapter;

(ii) Operating parameter records under §75.57(b)(1) through (4) of this chapter;

(iii) The records under §75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under §75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under §75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under §75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under §75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under §75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with §60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

§60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

OTHER REQUIREMENTS AND INFORMATION

§60.5570 What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under §60.8(b).

§60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.*, solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388-99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit*, *(*also known as "cogeneration") means a steam generating unit, IGCC, or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.*, electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.*, CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17), ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see §60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396-98 (incorporated by reference, see §60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975-08a (incorporated by reference, see §60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see §60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see §60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see §60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.*, meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.*, the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that result from a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (*e.g.*, CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.*, steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or 2 of this subpart.

Table 1 of Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction After January 8, 2014 and Reconstruction or Modification After June 18, 2014

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	**CO_2 Emission standard**
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC)	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh).

Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h)	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than:
	1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h; or
	2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

Table 2 of Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014 and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis]	50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input.

Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in §60.5525.

Table 3 to Subpart TTTT of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580.
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	No	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§60.8(c) – (f)	Conducting performance tests	No	
§60.9	Availability of Information	Yes	

§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13 (a) – (h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.

Hydrogen in Combustion Turbine Electric Generating Units

Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

Docket ID No. EPA-HQ-OAR-2023-0072

U.S. Environmental Protection Agency

Office of Air and Radiation

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Introduction

The use of hydrogen in the United States to date has been primarily limited to certain applications in industrial sectors. The nation produced approximately 10 million metric tons (MMT)[1, 2] of hydrogen in 2018 and 70% of that total was used by refineries to remove sulfur from petroleum products[3] and 20% was used to produce ammonia in the manufacture of fertilizer.[4] The remaining 10% was used for treating metals, processing foods, and other miscellaneous applications.[5] Hydrogen is also used in the transportation sector, currently in light duty hydrogen fuel cell vehicles.[6, 7, 8] Hydrogen does not contain carbon and therefore emits no carbon dioxide (CO_2) when combusted. This is the key to its potential for reducing greenhouse gas (GHG) emissions in hard-to-decarbonize industries that require a high heat source, such as cement and steel manufacturing.[9] For example, hydrogen can replace the metallurgical or coking coal and other fossil fuels used in a traditional blast furnace to reduce iron oxides to iron in the direct reduction of iron (DRI) process.

Potential Emissions Reductions from the Use of Hydrogen in Combustion Turbines

There is also interest in hydrogen as a viable, potentially low-GHG fuel source for combustion turbines in the utility power sector. Industrial combustion turbines have been burning byproduct fuels containing hydrogen for decades, and combustion turbines have been developed to burn syngas from the gasification of coal in integrated gasification combined cycle units.[10] The direct benefit of combusting 100% hydrogen to produce electricity is zero CO_2 emissions at the stack. However, there are several noteworthy physical characteristics of hydrogen as a fuel that present challenges to its widespread use as a GHG reduction strategy in utility combustion turbines.

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[1] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production.
[2] U.S. DOE (2018). *Fact of the Month May 2018: 10 Million Metric Tons of Hydrogen Produced Annually in the United States*. Accessed at https://www.energy.gov/eere/fuelcells/fact-month-may-2018-10-million-metric-tons-hydrogen-produced-annually-united-states.
[3] U.S. Energy Information Administration (EIA) (2016). *Hydrogen for refineries is increasingly provided by industrial suppliers*. Accessed at https://www.eia.gov/todayinenergy/detail.php?id=24612.
[4] New York State Department of Health (2005). *The Facts About Ammonia*. Accessed at https://www.health.ny.gov/environmental/emergency/chemical_terrorism/ammonia_tech.htm.
[5] National Renewable Energy Laboratory (NREL) (2022). *Hydrogen 101: Frequently Asked Questions About Hydrogen for Decarbonization*. Accessed at https://www.nrel.gov/docs/fy22osti/82554.pdf.
[6] Via U.S. Department of Energy, *Alternative Fuels Data Center*: In mid-2021, there were 48 open retail hydrogen stations in the United States. Additionally, there were at least 60 stations in various stages of planning or construction. Most of the existing and planned stations were in California, with one in Hawaii and 14 planned for the Northeastern states. Accessed at https://afdc.energy.gov/fuels/hydrogen_infrastructure.html.
[7] U.S. DOE (n.d.). *Alternative Fuels Data Center Alternative Fueling Station Locator*. Accessed at https://afdc.energy.gov/stations/#/find/nearest?fuel=HY&lpg_secondary=true&country=US&hy_nonretail=true.
[8] U.S. Energy Information Administration (EIA) (2022). *Hydrogen Explained.* Accessed at https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php.
[9] Bartlett, J., Krupnick, A. (2021). *The Potential of Hydrogen for Decarbonization: Reducing Emissions in Iron and Steel Production*. Resources. Accessed at https://www.resources.org/common-resources/the-potential-of-hydrogen-for-decarbonization-reducing-emissions-in-iron-and-steel-production/.
[10] Goldmeer, J. & Catillaz, J. (2021). *Hydrogen for power generation*. Retrieved July 13, 2021, Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.

One of the differences between hydrogen and natural gas (*i.e.*, methane) is the energy density by volume of the gases. To achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas. Blending or combusting such high volumes of hydrogen presents challenges to availability because of limited production and demand from other sectors, infrastructure (*i.e.*, distribution and transportation pipelines, storage), turbine design capabilities, and safety. High hydrogen blends by volume also have the potential to increase nitrogen oxide (NO_X) emissions from the combustion turbine as well as increase any upstream GHG emissions associated with the hydrogen production process. Since hydrogen and methane have different volume energy densities, when blending natural gas and hydrogen, the CO_2 emissions reduction is smaller than the volume% of hydrogen in the mixture. For example, to achieve a 50% reduction in EGU stack emissions of CO_2 requires a fuel blend that is approximately 75% hydrogen; a 75% CO_2 reduction requires a blend of 90% hydrogen. As a result, hydrogen-enriched fuels have a lower GHG intensity than typical natural gas fuels. To visualize, estimates of the carbon emissions reductions as a function of % hydrogen by volume for the working fuel is shown in Figure 1.

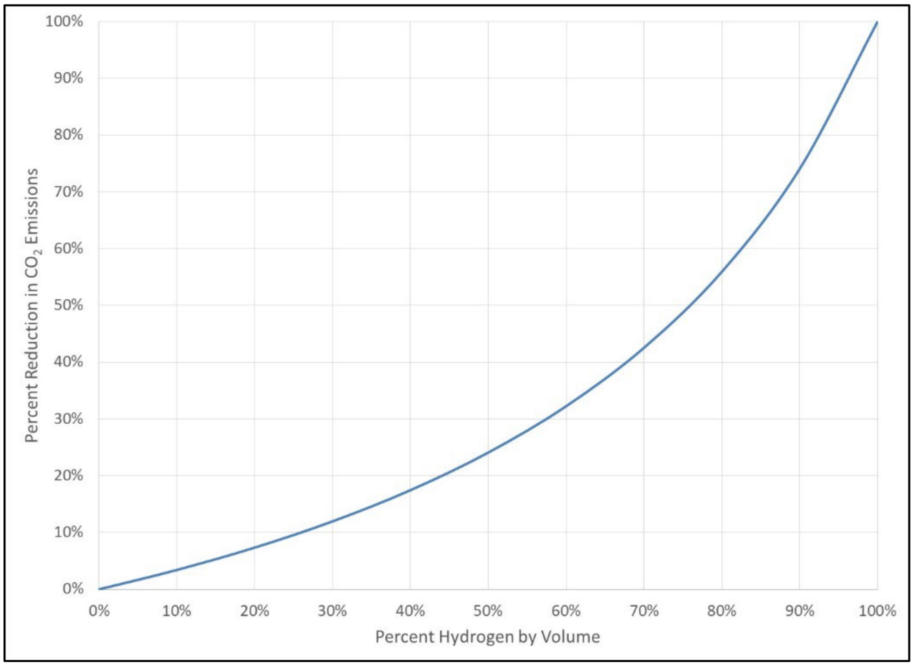

Figure 1: CO_2 Emission Reductions Varying % Hydrogen by Volume

Technical Feasibility of the Use of Hydrogen in Combustion Turbines

Other challenges of blending hydrogen in a combustion turbine EGU result from physical characteristics of the gas. It is necessary in combustion for the working fluid flow rate to move faster than the rate of combustion. Hydrogen gas typically combusts at a faster rate than natural gas. When the combustion speed is faster than the working fluid, a phenomenon known as “flashback” occurs, which can lead to upstream complications.[11] It is also important that hydrogen and natural gas are adequately mixed to avoid temperature hotspots, which can lead to

[11] Inoue, K., Miyamoto, K., Domen, S., Tamura, I., Kawakami, T., & Tanimura, S. (2018). *Development of Hydrogen and Natural Gas Co-firing Gas Turbine*. Mitsubishi Heavy Industries Technical Review. Volume 55, No. 2. June 2018. Accessed at https://power.mhi.com/randd/technical-review/pdf/index_66e.pdf.

formation of greater volumes of NO_X. As NO_X increases, a larger selective catalytic reduction (SCR) unit inside the heat recovery steam generator (HRSG) is needed. For combined cycle plants planning to co-fire higher percentages by volume of hydrogen with time, it is important to estimate the increased NO_X emissions when sizing the SCR unit.[12] Other differences include a hotter hydrogen flame compared to a natural gas flame and a wider flammability range for hydrogen than natural gas.[13] The high flame speed can lead to localized higher temperatures during the combustion process, which can also increase NO_X emissions depending on fuel characteristics.[14]

There are several examples of new combustion turbine installations planning to initially co-fire up to 30% hydrogen blends with natural gas and up to 100% when the additional fuel becomes available.[15] For example, the Long Ridge Energy Generation Project in southeast Ohio is a 485-megawatt (MW) combustion turbine that successfully completed a test burn of 5% (by volume) industrial byproduct hydrogen in 2022.[16,17] Eventually the facility intends to be capable of combusting 100% hydrogen.[18,19] Another example is the Intermountain Power Agency (IPA) project in Utah. IPA's project will replace ~~its~~ existing coal-fired EGU with an 840-MW combustion turbine that will have the capability to combust a blend of 30% low-GHG hydrogen in 2025 to meet the emissions requirements of the Los Angeles Department of Water and Power (LADWP). According to IPA, the long-term goal for the plant is to combust 100% hydrogen by 2045.[20] LADWP has also secured approval from the Los Angeles city council to convert its 297-MW Scattergood Generating Station to a 346-MW combined cycle combustion turbine capable

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[12] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.
[13] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines*. Accessed at http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf.
[14] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. Accessed at https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/.
[15] The use of hydrogen can result in increased emissions of NO_X, especially at larger percentages. This outcome could create challenges in certain areas of the country to attain ambient air quality standards. For EGUs, investments could be needed in refinements of combustion controls and potentially in advanced SCRs (Goldmeer and Catillaz, 2021).
[16] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal*. Retrieved September 30, 2021, https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/.
[17] Defrank, Robert (2022). *Cleaner Future in Sight: Long Ridge Energy Terminal in Monroe County Begins Blending Hydrogen*. Accessed at https://www.theintelligencer.net/news/community/2022/04/cleaner-future-in-sight-long-ridge-energy-terminal-in-monroe-county-begins-blending-hydrogen.
[18] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence*. Retrieved September 30, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio.
[19] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal*. Retrieved September 30, 2021, https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/.
[20] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence*. Retrieved September 30, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio.

of co-firing at least 30% low-GHG hydrogen.[21] LADWP specified the turbine would co-fire a minimum of 30% hydrogen, produced by electrolysis powered by renewable energy, on the first day and the unit would be operational by December 30, 2029.[22] The ultimate goal of the project is to burn 100% hydrogen by 2035, consistent with the city's climate objectives. In Illinois, a permit has been issued for the Lincoln Land Energy Center Project. The project is designed to provide 1.1 GW of power capacity with technology that will allow for up to a 30% hydrogen fuel blend upon initial operation with the capability to utilize 100% hydrogen by 2045.[23] Additionally, in Germany, a 100% hydrogen-fired combustion turbine is being piloted that is expected to have an output of 34 MW.[24] In Texas, El Paso Electric seeks to enable its Newman Power Station to co-fire 30% hydrogen and eventually 100% by 2045.[25]

There has been a successful co-firing of hydrogen at a demonstration project at Georgia Power's 2.5-GW Plant McDonough-Atkinson. The natural gas combustion turbine was able to co-fire a 20% hydrogen blend at both full and partial loads while maintaining emissions compliance and with no impact to maintenance intervals.[26] Additional proposed demonstration projects include the Brentwood power plant and the Cricket Valley Energy Center in New York. In September 2022, the New York Power Authority (NYPA) successfully demonstrated the ability to co-fire 44% 'carbon-free' hydrogen blended with natural gas in a retrofitted combustion turbine. According to NYPA, this was the first time an existing U.S. natural gas-fired combustion turbine has successfully been retrofitted to co-fire hydrogen, and according to the Electric Power Research Institute (EPRI), the project demonstrated a 14% reduction in CO_2 at a 35% hydrogen blend. The unit's existing SCR controlled NO_X emissions within permit limits.[27, 28, 29] Cricket Valley is planning to demonstrate co-firing a 5% blend of hydrogen at a combined cycle

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[21] Clark, K. (2023). *L.A. authorizes conversion of largest gas plant to hydrogen*. Power Engineering. See https://www.power-eng.com/hydrogen/l-a-authorizes-conversion-of-largest-gas-plant-to-green-hydrogen/#gref.
[22] Roth, S. (2023). *L.A. is shutting down its largest gas plant — and replacing it with an unproven hydrogen project*. The Los Angeles Times. See https://www.latimes.com/business/story/2023-02-08/l-a-is-shutting-down-a-coastal-gas-plant-and-replacing-it-with-hydrogen.
[23] Construction Review Online (2022). *Proposed 1.1GW Lincoln Land Energy Center Project in Illinois Approved.* Accessed at https://constructionreviewonline.com/news/proposed-1-1gw-lincoln-land-energy-center-project-in-illinois-approved/.
[24] Kawasaki (2021). *One of the World's First 100% Hydrogen-To-Power Demonstrations on Industrial Scale Launches in Lingen, Germany*. Accessed at https://global.kawasaki.com/news_211209-2e.pdf.
[25] Power Engineering (2021). *El Paso Electric, Mitsubishi Power collaborating on decarbonization plans*. Accessed at https://www.power-eng.com/emissions/el-paso-electric-mitsubishi-power-collaborating-on-decarbonization-plans/#gref.
[26] Patel, S. (2022). *Southern Co. Gas-Fired Demonstration Validates 20% Hydrogen Fuel Blend.* Accessed at https://www.powermag.com/southern-co-gas-fired-demonstration-validates-20-hydrogen-fuel-blend/.
[27] Palmer, W., & Nelson, B. (2021). *An H_2 Future: GE and New York power authority advancing green hydrogen initiative*. See https://www.ge.com/news/reports/an-h2-future-ge-and-new-york-power-authority-advancing-green-hydrogen-initiative" \t "_blank.
[28] Van Voorhis, S. (2021). New York to test green hydrogen at Long Island power plant. *Utility Dive*. https://www.utilitydive.com/news/new-york-to-test-green-hydrogen-at-long-island-power-plant/603130/.
[29] Electric Power Research Institute (EPRI). (2022, September 15). *Hydrogen Co-Firing Demonstration at New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine*. Low Carbon Resources Initiative. https://www.epri.com/research/products/000000003002025166.

facility.[30] In addition to other projects in New York, the integration of hydrogen and combustion turbines is planned for demonstration sites in Virginia, Ohio, Florida, Texas, and Louisiana, among others.[31, 32, 33, 34, 35]

Most existing combustion turbines commercially available for electric generation can burn hydrogen blends of 5 to 10% by volume without modification and blends as high as 20 or 30% by volume are being utilized in certain situations. Siemens currently offers heavy-duty combustion turbines with hydrogen blending capabilities of up to 30% by volume. Other offerings by Siemens include aeroderivative engines and medium industrial combustion turbines with 15% hydrogen by volume capability.[36] General Electric (GE) offers dry low emission (DLE) and dry low NOx (DLN) combustion turbines that can safely operate with up to 33% hydrogen by volume.[37] GE and Siemens both have goals to develop 100% hydrogen combustion capability in their turbines by 2030.[38, 39, 40] Mitsubishi Hitachi Power Americas is targeting development of 100% hydrogen combustion capable turbines by 2025.[41] According to Mitsubishi, several frame models that range between 30 and 1280 MW in size can co-fire 30% hydrogen with DLN technologies, and each of the available combustion turbine models is being developed to fire 100% hydrogen.[42]

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[30] General Electric (GE). (2021, July 20). *The road to zero: New York power plant teams with GE on 'green hydrogen' demonstration project*. https://www.ge.com/news/reports/the-road-to-zero-new-york-power-plant-teams-with-ge-on-green-hydrogen-demonstration-project.
[31] Mitsubishi Heavy Industries Group (MHI). (2020). *Mitsubishi Power cuts through the complexity of decarbonization: Offers the world's first green hydrogen standard packages for power balancing and energy storage*. https://power.mhi.com/regions/amer/news/20200902.html.
[32] Patel, S. (2020). Mitsubishi Power snags hydrogen integration contracts for 2 GW of new gas power. *Power*. https://www.powermag.com/mitsubishi-power-snags-hydrogen-integration-contracts-for-2-gw-of-new-gas-power/.
[33] Stromsta, K.-E. (2020, July 24). NextEra Energy to build its first green hydrogen plant in Florida. *GTM*. https://www.greentechmedia.com/articles/read/nextera-energy-to-build-its-first-green-hydrogen-plant-in-florida.
[34] Entergy (2022). *Entergy Texas receives approval to build a cleaner, more reliable power station in Southeast Texas*. Accessed at https://www.entergynewsroom.com/news/entergy-texas-receives-approval-build-cleaner-more-reliable-power-station-in-southeast-texas/.
[35] GE Gas Power (2022). Kindle Energy Awards 7HA.03 Combined-Cycle Plant Equipment Order to GE For Magnolia Power Plant with Hydrogen Capability to Support Energy Transition in Louisiana. Accessed at https://www.ge.com/news/press-releases/kindle-energy-awards-7ha03-combined-cycle-plant-equipment-order-to-ge-for-magnolia.
[36] Siemens (2020). Hydrogen power with Siemens gas turbines. https://www.infrastructureasia.org/-/media/Articles-for-ASIA-Panel/Siemens-Energy---Hydrogen-Power-with-Siemens-Gas-Turbines.ashx
[37] General Electric (GE) (2019, February). *Power to Gas: Hydrogen for Power Generation*. Accessed at https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.
[38] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030*. Accessed at https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.
[39] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines*. Accessed at https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.
[40] de Vos, Rolf (2022). *Ten fundamentals to hydrogen readiness*. Accessed at https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.
[41] Power Magazine (2019). *High Volume Hydrogen Gas Turbines Take Shape*. Accessed at https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.
[42] See https://power.mhi.com/special/hydrogen.

Hydrogen Production Methods

While hydrogen creates no GHG emissions when it is combusted, the emissions from the production and use of hydrogen can be significant. To fully evaluate the potential GHG reductions from using hydrogen as a fuel for combustion turbines, it is important to consider the different processes of hydrogen production.[43] Some of the different processes and energy sources for producing hydrogen are listed below in Figure 2.

Power Source	Production Process
Coal	Gasification with or without carbon capture and storage (CCS)
Natural Gas	Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) with or without CCS, Methane Pyrolysis
Nuclear	Thermal energy for gasification or SMR, Electrolysis (low and high temperature), and Thermochemical
Renewable	Electrolysis, Photoelectrochemical (PEC), Thermochemical
Others	Byproduct hydrogen and hydrogen derived from biomass, byproducts, and refuse

Figure 2: Hydrogen Production Methods

<u>Steam Methane Reforming and Coal Gasification</u>

Most of the dedicated hydrogen currently produced in the U.S. (more than 95%) originates from natural gas using a process known as steam methane reforming (SMR). The method works by adding steam, heat, and a catalyst to methane derived from natural gas. Methane reacts with the steam to produce hydrogen, carbon monoxide (CO), and trace amounts of CO_2. Further, the CO byproduct is routed to a second process, the water-gas shift reaction, to react with more steam to create additional hydrogen and CO_2. The CO_2 is then removed from the gas stream, leaving almost pure hydrogen.[44]

$$CH_4 + H_2O + heat \rightarrow CO + 3\,H_2 \qquad (1)$$

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (2)$$

A visual of SMR is depicted in Figure 3.

[43] Hydrogen can be produced through any of several different processes that emit varying amounts of GHGs. When these varying levels of GHG emissions associated with hydrogen production, including upstream emissions, are accounted for in an overall system GHG emissions analysis, there is currently no zero-GHG hydrogen. For example, electrolysis powered by solar or wind energy includes indirect upstream emissions of GHGs associated with building the system components and potential land use impacts. To attempt to recognize and differentiate between these varying levels of upstream emissions associated with hydrogen production, some organizations have developed a convention for labeling hydrogen according to a color scheme to characterize the production process (*e.g.*, gray, blue, green, etc.), though such labels are not used in this report.

[44] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production: Natural Gas Reforming*. Accessed at https://www.energy.gov/eere/fuelells/hydrogen-production-natural-gas-reforming. For each kg of hydrogen produced through SMR, 4.5 kg of water is consumed.

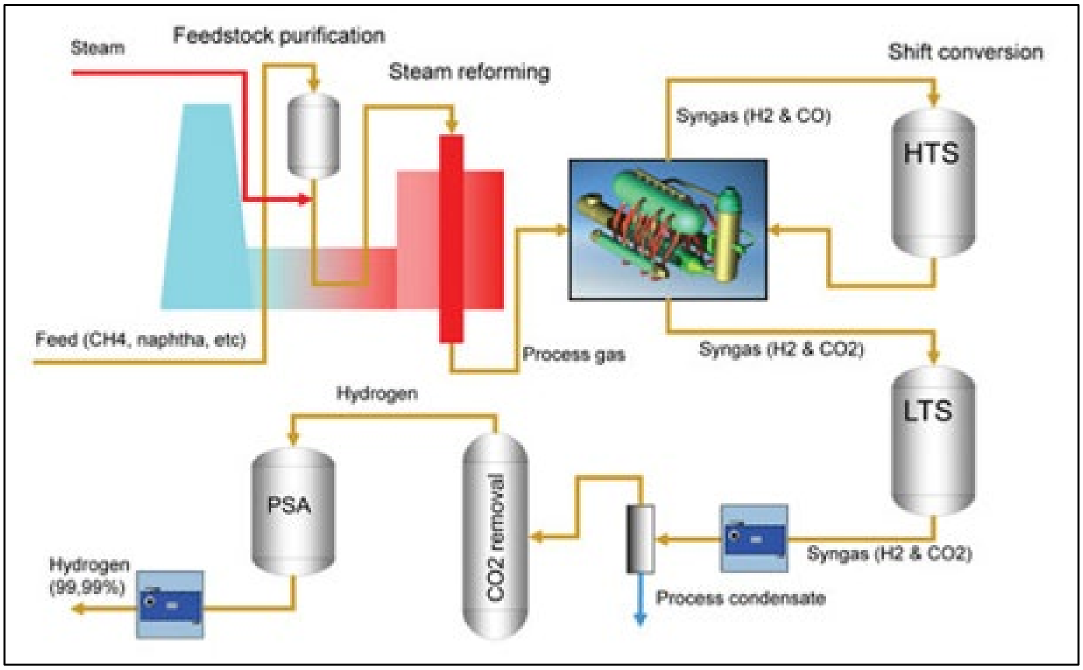

Figure 3: SMR Process Schematic[45]

Coal gasification is the second-largest source of dedicated hydrogen production domestically. Coal gasification is the process of creating hydrogen from coal by heating coal to high temperatures (up to 1,800 °C) in a closed vessel to create synthesis gas (*i.e.*, syngas). The syngas is composed of CO, CO_2, and hydrogen. The hydrogen is then removed from the syngas for usage. To make additional hydrogen, the CO can be routed to a shift reactor, where it is mixed with water, and a water-gas shift reaction occurs (like in SMR) resulting in additional hydrogen and CO_2.[46]

$$Coal + O_2 + Heat \rightarrow CO + CO_2 + H_2 \qquad (3)$$

$$CO + H_2O\ (steam) \rightarrow CO_2 + H_2\ (\text{water gas shift}) \qquad (4)$$

A visual of coal gasification is depicted in Figure 4.

45 World Oil (2021). *The U.S. DOE works on enhanced hydrogen production.* Accessed at https://www.worldoil.com/magazine/2021/november-2021/features/the-u-s-doe-works-on-enhanced-hydrogen-production/.
46 National Hydrogen Association, *Hydrogen – Production from Coal.* Accessed at https://www.mwcog.org/file.aspx?&A=6lJMMDOHmOUL2TT9fb7pcrAAeY5PdpMxMeZbS9eJzyo%3D.

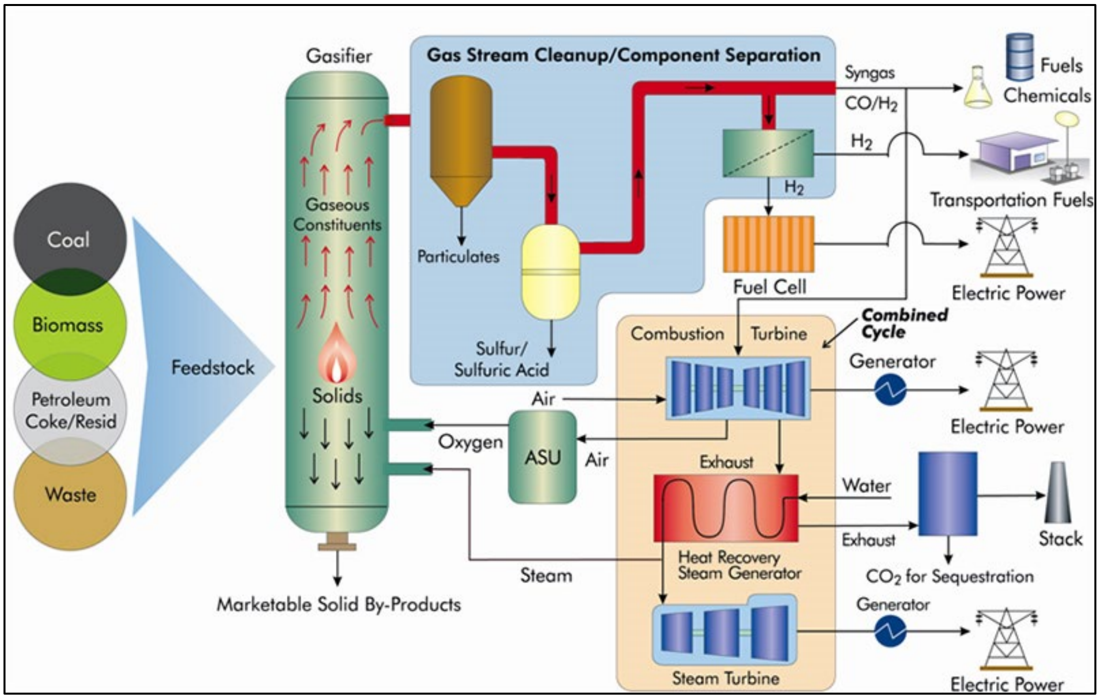

Figure 43: Gasification Process Schematic[47]

During conventional SMR or coal gasification, CO_2 emissions are created during the conversion process itself and from the creation of the thermal energy/steam (assuming the boiler used to create the steam is fueled by fossil fuels). From an overall GHG emissions perspective, the use of hydrogen from SMR would increase emissions approximately 50% compared to using the natural gas directly in a combustion turbine to produce electricity.[48] However, note that there are ways to improve the efficiency of SMR processes. One way is to use a membrane reactor. Specifically, a lead-based membrane reactor can allow an SMR reaction to occur at lower temperatures (450 to 550 °C) compared to normal SMR reactions, which occur at around 850 to 900 °C. Additionally, the lead-based membrane can lead to methane conversion efficiencies of 90 to 95%.[49, 50]

GHG emissions associated with hydrogen production can be partially controlled by capturing and sequestering CO_2 via CCS. Carbon capture can occur at different points in the hydrogen production process. Both SMR and coal gasification produce CO_2 in high concentrations (*i.e.*, 15

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[47] National Energy Technology Laboratory (NETL). *5.1. Gasification Introduction*. Accessed at https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/intro-to-gasification.
[48] Goldmeer, J. & Catillaz, J. (2021). *Hydrogen for power generation*. Retrieved July 13, 2021, Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.
[49] Nikolaidis, P., Poullikkas, A. (2016). *A comparative overview of hydrogen production processes*. Renewable and Sustainable Energy Reviews. Vol 67 (2017), 597-611. https://www.sciencedirect.com/science/article/pii/S1364032116305366?via%3Dihub.
[50] GHG intensities of hydrogen made using methane (SMR, ATR, and pyrolysis) also depend on the extent of methane leaks during the production and transportation of the natural gas feedstock. Anticipated regulations and advances in methane monitoring are expected to reduce these emissions and provide greater measurement certainty. Methane leakage rates, which have both air quality and air toxic impacts, are challenging to predict and are known to vary considerably by region.

to 50% CO_2) as part of the water-gas shift reaction. Due to the high concentrations of CO_2, carbon capture from shifted syngas is an efficient process. Pressure swing adsorption (PSA) is a common method to separate hydrogen and CO_2 in the shifted syngas stream. PSA works by binding gas molecules, in this case CO_2, to an adsorbent material. In the SMR process, the tail gas exiting the SMR reactor can be routed through the PSA process to bind CO_2 and other impurities to an adsorbent. Hydrogen does not adsorb well due to its high volatility and low polarity; thus, hydrogen passes through the PSA to be recovered.[51] The resulting hydrogen stream has a purity of greater than 99.99%. The separated CO_2-rich stream is usually sent back to the steam reformer to be combusted;[52] however, it can also undergo a carbon capture process at this point for efficient capturing and storage/utilization.

Through support from the Department of Energy (DOE), one facility currently utilizes a type of PSA, vacuum swing adsorption, at the industrial scale. The project, located at the Valero Port Arthur Refinery in Port Arthur, Texas, retrofitted two SMR units to capture more than 90% of the CO_2 from the product streams of its SMRs.[53] This project has demonstrated success at the industrial level, capturing more than 1 MMT of CO_2 each year.[54] It is estimated that coal gasification shifted syngas CCS technology costs approximately $60/tonne of CO_2 generated at an integrated gasification combined cycle (IGCC) power plant, and the DOE has a goal to reduce this cost to $30/tonne of CO_2.[55] In addition, CCS can be applied post-combustion to capture the CO_2 of the flue gas using chemical absorption processes.[56]

There are varying levels of CO_2 capture between the techniques, but typically a range of 65 to 90% of CO_2 is viable.[57]

ExxonMobil has announced plans for a hydrogen production facility with CCS at its refinery in Baytown, Texas, which could generate 1 billion cubic feet of hydrogen per day. The plans is to capture and permanently store more than 98% of the CO_2 produced by the facility.[58] Additionally, ExxonMobil's plan calls for replacing natural gas with hydrogen at its Baytown olefins plant, which may reduce the plant's CO_2 emissions by up to 30%. For CCS, the goal is to capture and store 100 MMT of CO_2 by 2040. Moreover, ExxonMobil is investigating a CCS

[51] Speight, J. G. (2019). *Heavy Oil Recover and Upgrading*. Chapter 15, Pages 657-697. Elsevier. https://www.sciencedirect.com/science/article/pii/B9780128130254000155.
[52] Reddy, S. & Vyas, S. (2009). *Recovery of Carbon Dioxide and Hydrogen from PSA Tail Gas*. Energy Procedia 1 (2009), 149-154. https://www.sciencedirect.com/science/article/pii/S187661020900023X?via%3Dihub.
[53] U.S. Department of Energy (DOE) (2017). *DOE-Supported CO_2-CaptureProject Hits Major Milestone: 4 Million Metric Tons*. Accessed at https://www.energy.gov/fecm/articles/doe-supported-co2-capture-project-hits-major-milestone-4-million-metric-tons.
[54] Valero (2022). *Carbon Capture: More Than One Million Tons of Carbon Dioxide*. Accessed at https://www.valero.com/responsibility/environmental-stewardship/recycling-process
[55] U.S. Department of Energy (DOE) (n.d.). *Pre-Combustion Carbon Capture Research*. Accessed at https://www.energy.gov/fecm/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd/pre-combustion-carbon.
[56] Madejski, P., Chmiel, K., Subramanian, N., Kuś, T. (2022). *Methods and Techniques for CO_2 Capture: Review of Potential Solutions and Applications in Modern Energy Technologies.* Energies 2022, 15(3), 887. https://doi.org/10.3390/en15030887.
[57] Powell, D. (2020). *Focus on Blue Hydrogen*. Gaffney Cline. Accessed at https://www.gaffneycline.com/sites/g/files/cozyhq681/files/2021-08/Focus_on_Blue_Hydrogen_Aug2020.pdf
[58] ExxonMobil (2023). *ExxonMobil awards FEED for world's largest low-carbon hydrogen facility*. Accessed at https://corporate.exxonmobil.com/news/newsroom/news-releases/2023/0130_exxonmobil-awards-feed-for-worlds-largest-low-carbon-hydrogen-facility.

project in Southampton, UK.[59] Additionally, Air Products is proposing a CCS development in Louisiana which would sequester 95% of process CO_2 emissions, storing more than 5 million tons per year in Louisiana. If constructed, the project would produce 750 million standard cubic feet per day of hydrogen for Air Products' pipeline customers.[60] Furthermore, BP and Linde have announced plans to build a CCS project in Texas resulting in low-GHG hydrogen at Linde's existing facilities. The project is scheduled to start up in 2026 and will store up to 15 MMT of CO_2 per year.[61] Another project has recently received its air quality permits from the state of Texas. OCI N.V. is prepared to begin construction at a facility that will enhance its existing ammonia plant in Beaumont by producing hydrogen via SMR with 95% CCS.[62] The new facility will capture an estimated 1.7 MMT of CO_2 per year and the hydrogen it produces will feed the adjacent ammonia plant by 2025, creating the largest ammonia production facility in Texas that makes hydrogen from natural gas and applied CCS. The ammonia will be used to decarbonize downstream industries, such as the fertilizer, food security, and energy sectors in the region.

Autothermal Reforming

A similar method to SMR is autothermal reforming of methane (ATR). The key difference is the use of high-purity oxygen in ATR, and therefore natural gas, steam, and oxygen are blended. The natural gas is partially oxidized by the oxygen in the furnace. The partial oxidation reaction is exothermic and provides the heat required for the endothermic reforming reaction. ATR's advantage over SMR is that the syngas and flue gas stream are not diluted with nitrogen, so CCS methods are easier to implement.

$$2\,CH_4 + O_2 + CO_2 \rightarrow 3\,H_2 + 3\,CO + H_2O \qquad (5)$$

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (6)$$

Methane Pyrolysis

An alternative method of hydrogen production from natural gas with is methane pyrolysis.[63] Pyrolysis is an endothermic non-combustion process that requires energy to be continuously added to the system. Methane pyrolysis is the thermal decomposition of methane in the absence (or near absence) of oxygen, which produces hydrogen and solid carbon (*i.e.*, carbon black) as the only byproducts. The pyrolysis chemical reaction is given in **Equation 6**.

[59] ExxonMobil (n.d.). *Hydrogen.* Accessed at https://corporate.exxonmobil.com/climate-solutions/hydrogen.
[60] Air Products (2022). *Louisiana Clean Energy Complex*. Accessed at https://www.airproducts.com/campaigns/la-blue-hydrogen-project.
[61] bp (2022). *bp and Linde plan major CCS project to advance decarbonization efforts across Texas Gulf Coast.* Accessed at https://www.bp.com/en_us/united-states/home/news/press-releases/bp-and-linde-plan-major-ccs-project-to-advance-decarbonization-efforts-across-texas-gulf-coast.html.
[62] OCI N.V. (2022). *OCI N.V. Breaks Ground on 1.1 mtpa Blue Ammonia Site in Texas, USA*. Accessed at https://www.businesswire.com/news/home/20221207005572/en/OCI-N.V.-Breaks-Ground-on-1.1-mtpa-Blue-Ammonia-Site-in-Texas-USA.
[63] Pacific Northwest National Laboratory. (2021). *New Clean Energy Process Converts Methane to Hydrogen with Zero Carbon Dioxide Emission*. Accessed at https://www.pnnl.gov/news-media/new-clean-energy-process-converts-methane-hydrogen-zero-carbon-dioxide-emissions.

$$CH_4 + Energy\ (\text{Heat}) \rightarrow C + 2\,H_2 \qquad (7)$$

For complete decomposition of methane, temperatures of 1,000° C or greater are typically required. However, the addition of catalysts can lower the temperature needed for the pyrolysis reaction to take place. Some nickel or iron catalysts can lower the temperature of the reaction to 700° C. Similarly, carbon catalysts can also work to reduce the temperature of the reaction to 800° C.[64] Moreover, because carbon and hydrogen are the only byproducts, there is no process CO_2 that needs to be captured.[65] Methane pyrolysis has a net energy efficiency of approximately 60%.

Three different types of pyrolysis systems exist: plasma reactor systems, molten metal reactor systems, and conventional gas reactor systems. Plasma reactor systems use thermal plasma[66] as the heat supply and are highly selective in the process. Due to its fast start up, the process can powered with renewable, intermittent energy sources (*i.e.*, solar/wind). Molten reactor systems work by injecting methane into a reactor containing liquid metal, whereby carbon will rise to the surface and hydrogen will leave the reactor at the top. Different metals can be used, with selection of a catalytic active metal (Ni, Bi) resulting in a higher hydrogen yield. A gas reactor system works by decomposing methane within a fluidized- or fixed-bed reactor.[67] The three pyrolysis systems result in varying electricity and methane consumptions, and thus related GHG emissions, and these specifications are outlined in Figure 5.

Reactor System	**Heat supply**	**Electricity Consumption (kWh/kg H_2)**	**CH_4 Consumption (MJ/kg H_2)**
Thermal Plasma	Thermal Plasma	13.9 (11.1 – 17.8)	223.0 (222.1 – 242.3)
Molten Metal	CH_4	0 (-0.5 – 0.3)	272.7 (252.6 – 272.7)
Gas Reactor	CH_4	0 (0 – 2.3)	299.0 (266.8 – 332.5)

Figure 4: Comparison of electricity and methane consumption in pyrolysis systems[68]

One company has successfully demonstrated methane pyrolysis at the commercial scale. *Monolith's* Olive Creek 1 plant converts natural gas and nitrogen to carbon black with an ammonia byproduct.[69] The *Monolith* process works by using thermal energy to superheat natural gas in a combustion-free and CO_2-free process that breaks the bonds between the hydrogen and

[64] Sánchez-Bastardo, N., Schlögl, R., Ruland, H. (2021). *Methane Pyrolysis for Zero-Emission Hydrogen Production: A Potential Bridge Technology from Fossil Fuels to a Renewable and Sustainable Hydrogen Economy*. American Chemical Society. https://doi.org/10.1021/acs.iecr.1c01679.
[65] Thermal energy is required for the pyrolysis and there will be GHG emissions associated with the hydrogen production process.
[66] Thermal plasma is generated by passing an electric current through the natural gas.
[67] Timmerberg, S., Kaltschmitt, M., Finkbeiner, M. (2020). *Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas - GHG emissions and costs*. Energy Conversion and Management: X. https://doi.org/10.1016/j.ecmx.2020.100043.
[68] Timmerberg, S., Kaltschmitt, M., Finkbeiner, M. (2020). *Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas - GHG emissions and costs*. Energy Conversion and Management: X. https://doi.org/10.1016/j.ecmx.2020.100043.
[69] Department of Energy (DOE) Loan Programs Office (2021). *Environmental Assessment – Monolith Olive Creek Expansion Facility*. Accessed at https://www.energy.gov/sites/default/files/2022-04/fonsi-and-ea-2180-monolith-olive-creek-expansion-facility-2021-12.pdf.

carbon in the natural gas molecules.[70] Note that electricity is used to provide the thermal energy to decompose the methane. However, *Monolith* states that its pyrolysis process has a reduced electricity demand by a factor of 7 when compared to electrolysis.[71]

Hydrogen Derived from Nuclear Energy

There are multiple options for using nuclear energy to produce hydrogen—supplying thermal energy to the gasification, SMR, and pyrolysis processes, thermochemical, and electrolysis. The first option is using thermal energy from the nuclear reaction to replace the thermal energy in the gasification, SMR, or pyrolysis hydrogen production methods. Even though the electrical generating efficiency of the nuclear EGU would be reduced, replacing the fossil fuels needed to generate the thermal energy required for the hydrogen production process would reduce overall GHGs.[72]

Carbon intensity for SMR hydrogen production can be decreased if steam required for the reaction is provided via a nuclear EGU. It is estimated that a nuclear heat source can reduce natural gas consumption by around 30% and eliminate flue gas CO_2 emissions.[73]

Thermochemical water splitting processes use high-temperature heat (500 to 2,000 °C) to drive a series of chemical reactions that produce hydrogen.[74, 75] The chemicals used in the process are reused within each cycle, creating a closed loop that consumes only water and produces hydrogen and oxygen. The high-temperature thermal energy can be supplied as a byproduct of a high-temperature nuclear reactor or concentrating solar thermal array. More than 300 water splitting cycles have been proposed; although, one popular method is the copper chloride (Cu-Cl) water splitting cycle, which operates at around 500 °C.[76] In the Cu-Cl water splitting cycle, copper and chloride compounds are recycled in a closed loop throughout a series of reactions. Thus, the overall products are hydrogen and oxygen, with the copper and chloride compounds being reused. Heat energy from a nuclear reactor's waste heat can be supplied for each of the steps to reach appropriate temperatures.[77]

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70 Monolith. *Methane Pyrolysis*. Accessed at https://monolith-corp.com/methane-pyrolysis.
71 Monolith. *Process Comparison*. Accessed at https://monolith-corp.com/process-comparison.
72 If a hydrogen production facility were located in close proximity to a nuclear EGU, the EGU could provide the bulk of the thermal energy required for the production of hydrogen. During periods of peak electric demand, the EGU could reduce the thermal energy being sent to the hydrogen production facility to maximize electrical output.
73 World Nuclear Association (2021). *Hydrogen Production and Uses.* Updated November 2021. Accessed at https://world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx.
74 DOE. *Hydrogen Production: Thermochemical Water Splitting*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-thermochemical-water-splitting.
75 High-temperature reactors could be used to decompose water directly to hydrogen (and byproduct oxygen) using a thermochemical process. See https://www.world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx.
76 DOE. *Hydrogen Production: Thermochemical Water Splitting*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-thermochemical-water-splitting.
77 Orhan, M. F., Dincer, I., Naterer, G. F., & Rosen, M. A. (2010). *Coupling of copper-chloride hybrid thermochemical water splitting cycle with a desalination plant for hydrogen production from nuclear energy*. International Journal of Hydrogen Energy. Volume 35, Issue 4, February 2010, Pages 1560 – 1574. https://doi.org/10.1016/j.ijhydene.2009.11.106.

The final approach to producing hydrogen from nuclear energy is through electrolysis, which is discussed in the next section.

Electrolysis

Electrolysis is the process of splitting water into its components, hydrogen and oxygen, via electricity. During electrolysis, a negatively charged cathode and positively charged anode are submerged in water and an electric current is passed through the water. The result is hydrogen molecules appearing at the negative cathodes and oxygen appearing at the positive anodes.

The energy intensity of electrolysis is high, so potential GHG emission reductions from the use of hydrogen versus fossil fuels in a combustion turbine are largely dependent on the form of energy used to power the hydrogen production process. If that form of energy is renewable (*e.g.*, solar) or nuclear, then the GHG reductions associated with using hydrogen as a fuel could be significant.[78,79]

$$H_2O + Electricity \rightarrow H_2 + \frac{1}{2}\, O_2 \qquad (8)$$

Electrolysis can be achieved through different configurations. High-temperature (>500 °C) electrolysis is more efficient than low-temperature electrolysis because the increased temperature causes the water molecules to break down more easily. The temperature increase can be raised through nuclear power (or fossil-fired) power plants' waste heat. For comparison, low-temperature electrolysis typically operates at less than 100 °C.[80] Less-efficient, low-temperature electrolyzer technologies currently exist commercially at the MW scale, whereas high-temperature electrolyzer technologies are less developed.[81] High-temperature electrolysis can be 30 to 50% more efficient compared to low-temperature electrolysis[82], with low-temperature electrolysis currently reaching efficiencies of around 60%.[83] As of 2020, only 1% of hydrogen was produced via electrolysis.

DOE is currently supporting four hydrogen demonstration projects at nuclear power plants. In Oswego, New York, a low-temperature electrolysis system is being constructed at the Nine Mile

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78 U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production: Electrolysis*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis#:~:text=Electrolysis%20is%20a%20promising%20option,a%20unit%20called%20an%20electrolyzer.

79 For each kg of hydrogen produced through electrolysis, 9 kg of byproduct oxygen are also produced and 9 kg of purified water are consumed. To reduce the cost of hydrogen production, this byproduct oxygen could be captured and sold. For each gallon of water consumed, 0.057 MMBtu of hydrogen is produced. According to the water use requirements for combined cycle EGUs with cooling towers, if this hydrogen is later used to produce electricity in a combined cycle, EGU overall water requirements would be greater than a combined cycle EGU with CCS.

80 Badwal, S. P. S., Giddey, S., Munnings, C. (2012). *Hydrogen production via solid electrolytic routes*. Wires Energy and Environment, Volume 2, Issue 5. https://doi.org/10.1002/wene.50.

81 U.S. Department of Energy (DOE) (2021). *Hydrogen Technologies – 2021*. FY 2021 Merit Review and Peer Evaluation Report. Accessed at https://www.hydrogen.energy.gov/pdfs/review21/2021-amr-04-hydrogen-technologies.pdf.

82 Boardman, R. D., Ding, D. (2019). *HydroGEN: High-Temperature Electrolysis*. 2019 DOE Annual Merit Review. Accessed at https://www.hydrogen.energy.gov/pdfs/review19/p148B_boardman_2019_p.pdf.

83 Burton, N. A., Padilla, R. V., Rose, A., Habibullah, H. (2021). *Increasing the efficiency of hydrogen production from solar powered water electrolysis.* Renewable and Sustainable Energy Reviews. Volume 135, January 2021, 110255. https://www.hydrogen.energy.gov/pdfs/review19/p148B_boardman_2019_p.pdf.

Point Nuclear Power Station. This project aims to start producing hydrogen by the end of 2022 and will use hydrogen to help cool the plant. In Oak Harbor, Ohio, a low-temperature electrolysis system is being constructed at the Davis-Besse Nuclear Power Station. This project's goal is to prove the feasibility and economic benefits of clean hydrogen production, and it is expected to produce hydrogen by 2023. In Red Wing, Minnesota, high-temperature electrolysis is going to be implemented for hydrogen production, with production expected to begin in 2024. In Tonopah, Arizona, DOE is negotiating an award for a low-temperature electrolysis system at the Palo Verde Generating Station. This station is aiming to produce hydrogen in 2024.[84]

There are three electrolysis technologies currently in use, with the main difference between them being the electrolytes within the electrolyzer. Polymer electrolyte membrane (PEM) electrolysis uses a proton exchange membrane as the electrolyte, usually made from a solid specialty plastic material. Typical PEM electrolyzer operating temperature ranges between 70 and 90 °C with an electrical efficiency of 56 to 60%.[85] A potential advantage of PEM electrolyzers is their ability to respond quickly to fluctuations, which are typical for intermittent sources of electricity such as renewables and could be used to produce hydrogen from electricity that might otherwise be curtailed. Alkaline electrolysis uses a liquid solution of sodium or potassium hydroxide as the electrolyte and has a normal operating temperature of less than 100 °C. Electrical efficiency for alkaline electrolysis ranges between 63 and 70%. Solid oxide electrolysis uses a solid ceramic material as the electrolyte that selectively conducts negatively charged oxygen ions at elevated temperatures at an electrical efficiency of 74 to 81%. Temperatures of 700 to 800 °C are necessary for the solid oxide membranes to function properly.[86] If waste heat is used as a source of thermal energy, the overall efficiency of electrolysis from solid oxide fuel cells could be increased. Anion exchange membrane (AEM) electrolyzer technology is under development and is similar to a PEM electrolyzer technology, except the hydroxyl ions are transported across the membrane. A potential advantage of AEM technology relative to PEM technology is the ability to use lower cost catalysts.

Electrolysis uses fuel cells to split water into hydrogen and oxygen. Some of these electrolysis systems, such as PEM and alkaline electrolysis, only produce hydrogen and oxygen from the fuel cells. Solid oxide electrolysis has the capability to operate additionally as a reversible technology, in which hydrogen can be used in the fuel cell to produce electricity. Therefore, a solid oxide electrolyzer could produce hydrogen for stored energy and then use the hydrogen to produce electricity. These reversible power-to-gas systems can be used as a source of backup electricity during periods of surging prices and peak demand. They could also potentially produce electricity from hydrogen at cheaper costs than combustion turbines, especially as the cost effectiveness improves as the technology matures.[87]

Given that no GHG emissions are released during the electrolysis process, emissions from electrolysis hydrogen production are largely dependent on the source of electricity.

[84] DOE (2022). *4 Nuclear Power Plants Gearing Up for Clean Hydrogen Production*. Accessed at https://www.energy.gov/ne/articles/4-nuclear-power-plants-gearing-clean-hydrogen-production.
[85] IEA (2019, June). *The Future of Hydrogen Report, prepared by the IEA for the G20, Japan*. Accessed at https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.
[86] Hydrogen and Fuel Cell Technologies Office. *Hydrogen Production: Electrolysis*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.
[87] Edmund, Andrews (2022, April 20). *Reversible fuel cells can support grid economically, Stanford researcher finds*. https://news.stanford.edu/press-releases/2022/04/20/reversible-fuel-rid-economically/.

Example Electrolysis Projects

For the Long Ridge, IPA, Brentwood, and Cricket Valley projects mentioned previously, the objective is for those facilities to eventually transition to hydrogen produced from renewable energy and electrolysis as it becomes available. In Texas, Air Products is partnering with energy firm AES to build a $4 billion hydrogen complex that uses electrolysis and low-carbon energy inputs. The site will use water electrolyzers powered by 1.4 gigawatts (GW) of wind and solar facilities to produce 200 metric tons of hydrogen per day.[88] In Europe, several projects have been announced that will utilize offshore wind energy to power onshore electrolysis. Hydrogen produced in this manner can be used to produce electricity and for other industries in the area and likely incorporated into their "low-GHG" products. For example, a Danish energy company has begun a project called "SeaH2Land" in which 2 GW of offshore wind in the Dutch North Sea will power the electrolysis of hydrogen.[89] The hydrogen will then be utilized by industries in the North Sea Port areas of the Netherlands and Belgium—home to industries such as ArcelorMittal (steel), Yara (ammonia), Dow (material sciences), and the Zeeland Refinery (reformed methane).[90, 91]

At the National Wind Technology Center in Boulder, Colorado, DOE's National Renewable Energy Laboratory (NREL) has partnered with Xcel Energy on a wind-to-hydrogen demonstration project. Powered by wind turbines and photovoltaic arrays, hydrogen is produced via electrolysis and then stored[92] or converted to electricity by an internal combustion engine or fuel cell and fed to the grid at peak demand (NREL, n.d.). The goal of this "Wind2H2" project is to research pathways to improve system efficiencies, reduce costs, and increase competitiveness with traditional fossil fuels (NREL, n.d.).

Multiple electrolyzer factories are under development in the United States. Cummins Inc. will use an existing facility in Fridley, Minnesota to manufacture 500 megawatts of electrolyzers annually, with the possibility to grow to 1 gigawatt. Cummins will manufacture PEM electrolyzes that range from 1.25 MW to over 200 MW.[93] Bloom Energy has a high volume commercial electrolyzer line at its facility in Newark, Delaware, bringing its total generating

[88] Chemical & Engineering News (2022). *Air Products plans big green hydrogen plant in US*. Accessed at https://cen.acs.org/energy/hydrogen-power/Air-Products-plans-big-green/100/web/2022/12.

[89] See https://orsted.com/en/media/newsroom/news/2021/04/451073134270788/.

[90] Frangoul, A. (2021). *Orsted to link a huge offshore wind farm to "renewable" hydrogen production*. CNBC. Retrieved August 4, 2021, https://www.cnbc.com/2021/04/01/orsted-to-link-huge-offshore-wind-farm-to-hydrogen-production-.html.

[91] Orsted. (2021). *Orsted to develop one of the world's largest renewable hydrogen plants to be linked to industrial demand in the Netherlands and Belgium*. Retrieved August 4, 2021, https://orsted.com/en/media/newsroom/news/2021/04/451073134270788.

[92] Currently available utility batteries typically have 4 hours or less of storage and are not used for long-term storage. Longer-term storage is typically done using pumped hydro or compressed air. A potential use of hydrogen is to serve as long-term energy storage. Electricity generated from renewables or nuclear power during periods of low electric demand can be converted to hydrogen and stored onsite for long periods. In addition, if this hydrogen is injected into the existing natural gas distribution network, the distribution system itself can act as the storage device. Another advantage of injecting low-GHG hydrogen into the existing natural gas transmission network is that the energy from renewable generation can be transported to end users without using the electric grid—potentially reducing the need for additional transmission capacity and the associated negative environmental and societal impacts.

[93] Freight Waves (2022). *Cummins adding hydrogen electrolyzer manufacturing in US. Accessed at https://www.freightwaves.com/news/cummins-adding-hydrogen-electrolyzer-manufacturing-in-us.*

capacity of eletrolyzers to 2 gigawatts.[94] Plug Power operates a Gigafactory in Monroe County, New York where it manufactures PEM electrolyzers for low-GHG hydrogen production.[95]

<u>Photochemical</u>

Photoelectrochemical (PEC) water splitting can be used to produce hydrogen with low GHG emissions. In this process, specialized semiconductors called photoelectrochemical materials use light energy from sunlight to directly dissociate water molecules into hydrogen and oxygen. A major advantage of PEC systems is that they possess a wide operating temperature range, with no intrinsic upper temperature limit. The lower temperature limit can be slightly below 0 °C without a warm-up period, and well below 0 °C with a warm-up period. The main challenges for PEC are lifespan, dealing with corrosion, internal resistance losses, high plant capital cost, and material development.[96] Photocatalytic overall water splitting (OWS) is a variation of water splitting. Compared with PEC, photocatalytic OWS does not require the use of a conductive electrolyte such as strong acidic or alkaline solutions. Fresh or sea water can be split into hydrogen and oxygen without external bias or circuitry, potentially leading to reduced system cost and safety issues.[97]

<u>Byproduct Hydrogen</u>

Hydrogen can also be produced as a byproduct of other industrial/manufacturing processes. A few examples of additional production techniques where hydrogen is produced include refuse biomass, chlor-alkali plants, and waste hydrocarbons.[98] From refuse biomass, anerobic digestion occurs, which results in biogas. Biogas is a significant portion methane, which can be converted to hydrogen via upgrading processes. As for chlor-alkali production, highly pure hydrogen is a byproduct of the process and carries a low carbon footprint.[99] Currently, approximately 15% of the chlor-alkali hydrogen produced is vented.[100] Waste hydrocarbons can be fed into a reformer

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[94] Bloom Energy (2022). *Bloom Energy Inaugurates High Volume Electrolyzer Production Line.* Accessed at https://www.bloomenergy.com/news/bloom-energy-inaugurates-high-volume-electrolyzer-production-line/.

[95] NY Governor’s Press Office (2021). *Governor Hochul Announces Opening of $125 Million Plug Power Hydrogen Fuel Cell Innovation Center in Monroe County*. Accessed at https://www.governor.ny.gov/news/governor-hochul-announces-opening-125-million-plug-power-hydrogen-fuel-cell-innovation-center.

[96] James, B. D., et al (2009). *Technoeconomic Analysis of Photoelectrochemical (PEC) Hydrogen Production*. Draft Project Final Report. Accessed at https://www.energy.gov/sites/default/files/2014/03/f12/pec_technoeconomic_analysis.pdf.

[97] Zhou, P., et al (2023). *Solar-to-hydrogen efficiency of more than 9% in photocatalytic water splitting*. Accessed at https://www.nature.com/articles/s41586-022-05399-1.

[98] Cox, R. (2011). *Waste/By-Product Hydrogen*. DOE/DOD Workshop, January 13, 2011. Accessed at https://www.energy.gov/sites/prod/files/2014/03/f12/waste_cox.pdf.

[99] Euro Chlor (2022). *Hydrogen from Chlor-Alkali Production: High Purity, Low Carbon and Available Today*. Accessed at https://www.eurochlor.org/news/hydrogen-from-chlor-alkali-production/.

[100] James, B. D., et al (2009). *Technoeconomic Analysis of Photoelectrochemical (PEC) Hydrogen Production*. Draft Project Final Report. Accessed at https://www.energy.gov/sites/default/files/2014/03/f12/pec_technoeconomic_analysis.pdf.

to convert them into hydrogen, as has been done Ford Motor Company's 'Fumes-to-Fuel' waste paint exhaust system.[101]

Natural Hydrogen

Natural hydrogen is also present in geologic formations created by chemical reactions between water and iron mineral deposits, namely olivine, under high temperature and pressure.[102] GHG emissions associated with subsurface hydrogen, if present, would be a result of fossil-based extraction and production process. While no natural hydrogen projects are currently operational, given the tax incentives discussed in the ***Infrastructure Investment and Jobs Act*** section below, additional methods of hydrogen production are likely to evolve over the next ten years.

Transportation and Storage of Hydrogen

A viable hydrogen infrastructure requires that hydrogen be able to be delivered from where it is produced to the point of end use, such as an industrial facility, power generator, or fueling station. That infrastructure also must be able to deliver hydrogen to the point of use at the times needed, requiring storage infrastructure. Infrastructure includes the pipelines, liquefaction plants, trucks, storage facilities, compressors, and dispensers involved in the process of delivering fuel.[103]

Hydrogen is transported from the point of production to the point of use via pipelines and over the road in cryogenic liquid tanker trucks or gaseous tube trailers. Pipelines are deployed in regions with substantial demand (*e.g.*, hundreds of tons per day) that is expected to remain stable for decades. Liquefaction plants, liquid tankers, and tube trailers are deployed in regions where demand is at a smaller scale or emerging. Demonstrations of hydrogen delivery via chemical carriers (*e.g.*, in barges) are also underway in large-scale applications, such as export markets.[104] It can be transported as a gas by pipelines or in liquid form by ships, much like liquefied natural gas (LNG).[105]

The cost of hydrogen delivery, storage, and dispensing to an end-user varies widely given the mode of supply used. There are four main methods of hydrogen delivery at scale today: gaseous tube trailers, liquid tankers, pipelines (for gaseous hydrogen), and chemical hydrogen carriers. Tube trailers and liquid tankers are commonly used in regions where hydrogen demand is developing and not yet stable. Gaseous pipelines are commonly used when demand is predictable for decades and at a regional scale of hundreds of tonnes per day. Chemical carriers are of interest for long-distance hydrogen delivery.

[101] Environmental News Network (ENN) (2007). *Ford 'Fumes-to-Fuel' System Turns Waste Paint Exhaust into Clean Electric Power*. Accessed at https://www.enn.com/articles/22537-ford-fumes-to-fuel-system-turns-waste-paint-exhaust-into-clean-electric-power#:~:text=Installed%20in%20the%20Paint%20Shop,into%20a%20hydrogen%2Drich%20gas.
[102] "Hidden Hydrogen: Does Earth hold vast stores of a renewable, carbon-free fuel" Science, February 16, 2023
[103] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Delivery*, https://www.energy.gov/eere/fuelcells/hydrogen-delivery.
[104] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Delivery*, https://www.energy.gov/eere/fuelcells/hydrogen-delivery.
[105] IEA, *The Future of Hydrogen Report* (June 2019), prepared by the for the G20, Japan. Accessed at https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.

The California Public Utilities Commission (CPUC) commissioned the University of California, Riverside's *Hydrogen Blending Impacts Study* to assess the operational and safety concerns associated with injecting hydrogen into the existing natural gas pipeline system at various percentages to help California establish the standards and interconnection protocols for possibly injecting renewable hydrogen into natural gas pipelines.[110]

The Study's findings include:

- Hydrogen blends of up to 5% in the natural gas stream are generally safe. However, blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.
- Hydrogen blends above 5% could require modifications of appliances such as stoves and water heaters to avoid leaks and equipment malfunction.
- Hydrogen blends of more than 20% present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside the pipeline.
- Due to the lower energy content of hydrogen gas, more hydrogen-blended natural gas will be needed to deliver the same amount of energy to users compared to pure natural gas.

Transporting gaseous hydrogen via existing pipelines is a low-cost option for delivering large volumes of hydrogen. The high initial capital costs of new pipeline construction constitute a major barrier to expanding hydrogen pipeline delivery infrastructure. Research today therefore focuses on overcoming technical concerns related to pipeline transmission, including:

- the potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines;
- the need to control hydrogen permeation and leaks; and
- the need for lower cost, more reliable, and more durable hydrogen compression technology.

The United States has an extensive network of approximately three million miles of natural gas pipelines and more than 1,600 miles of dedicated hydrogen pipeline. Hydrogen, including hydrogen produced through low-GHG pathways, can be injected into natural gas pipelines and the resulting blends can be used to generate heat and power with lower emissions than using natural gas alone. Blend limits depend on the design and condition of current pipeline materials (*e.g.*, integrity, dimensions, materials of construction), design and condition of pipeline infrastructure equipment (*e.g.*, compressor stations), and design and condition of applications that utilize natural gas (*e.g.*, building appliances, turbines, and chemical processes, such as plastics production). Blend limits can vary greatly based on these variables but have ranged from <1 to 30% in recently announced demonstrations and deployments.[111] Amounts that can be mixed vary by region. Analysts assert that 20% hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required. Other recent analyses of existing pipeline materials indicate that 12% may be the maximum blend.[112] In addition, the end-use equipment in power plants and industrial facilities may not tolerate higher hydrogen

[110] University of California, Riverside for the CPUC, *Hydrogen Blending Impacts Study* (July 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems
[111] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines* (June 2021)
[112] https://www.ornl.gov/publication/assessing-compatibility-natural-gas-pipeline-materials-hydrogen-co2-and-ammonia

concentrations without modification.[113] If implemented with relatively low concentrations, less than 5 to 15% hydrogen by volume, this strategy of storing and delivering low-GHG hydrogen to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis. Any introduction of a hydrogen blend concentration would require extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices (*e.g.*, integrity management systems).[114]

Note that the concerns relating to natural gas pipeline embrittlement from hydrogen transportation have been disputed.[115] Nonetheless, potential solutions exist to protect existing natural gas pipelines from embrittlement caused by hydrogen use. These solutions include using fiber reinforced polymer (FRP) pipelines for hydrogen distribution (FRP can be delivered in lengths of up to 0.5 mile).[116] The installation costs for FRP pipelines are about 20% less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel[117] minimizing welding requirements.

Other changes necessary to retrofit natural gas pipeline distribution systems for hydrogen distribution include installing appropriate compressors. One case study estimated the compressor replacement/alterations that would be necessary to transport varying proportions of hydrogen in existing natural gas pipelines in Germany. Findings suggest that when transporting up to 10% hydrogen, generally no changes are needed to existing compressors. When transporting between 10-40% hydrogen, impellers, feedback stages, and gears need to be adjusted on the existing compressors. When transporting over 40% hydrogen, compressors need to be replaced. Additionally, if transport capacities exceed 750,000 Nm^3/h, it is estimated that turbo-compressors[118] are required.[119]

The integration of hydrogen in pipelines has already been demonstrated. Air Products has constructed 180 new miles of pipeline in the Gulf Coast. Combined, the network consists of over 600 miles of pipeline and 20 hydrogen plants that can supply nearby refineries with more than 1 billion cubic feet of hydrogen per day.[120] In California, Southern California Gas (SoCalGas) has begun the development of a hydrogen pipeline system that could deliver low-GHG hydrogen

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[113] Congressional Research Service, Parfomak, P., *Pipeline Transportation of Hydrogen: Regulation, Research and Policy* (March 2021) https://crsreports.congress.gov/product/pdf/R/R46700
[114] NREL/TP-5600-51995, Melaina, M.W., Antonia O., and Penev, M., (March 2013). *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*
[115] Nationaler Wasserstoffrat (2021). *Wasserstofftransport*. (In German.) Accessed at https://wasserstoffwirtschaft.sh/file/nwr_wasserstofftransport_web-bf.pdf.
[116] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Pipelines*, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines
[117] Argonne National Laboratory, *Natural Gas Pipeline Technology Overview*, https://doi.org/10.2172/925391
[118] Turbo-compressors are estimated to be available “within a few years” according to the case study.
[119] Adam, P., Heunemann, F., von dem Bussche, C., Engelshove, S., Theimann, T. (2021). *Hydrogen infrastructure – the pillar of energy transition*. Accessed at https://assets.siemens-energy.com/siemens/assets/api/uuid:3d4339dc-434e-4692-81a0-a55adbcaa92e/200915-whitepaper-h2-infrastructure-en.pdf?ste_sid=81652be676b733c416f088cae17fccf3.
[120] Air Products (2012). *Air Products' U.S. Gulf Coast hydrogen network*. Accessed at https://microsites.airproducts.com/h2-pipeline/pdf/air-products-us-gulf-coast-hydrogen-network-datasheet.pdf.

equivalent to 25% of the company's natural gas capacity. The project would deliver hydrogen from electrolyzers powered by clean energy straight to end users, primarily electrical generation, transportation, and industry.[121] SoCalGas has also submitted proposals to blend up to 20% hydrogen in natural gas pipelines for combustion in California.[122]

Hydrogen pipelines themselves serve as energy storage devices can also act as an alternative to transmission lines for energy transport. Hydrogen electrolysis can be used to convert renewable energy into hydrogen, which can then be sent through pipelines. Building a hydrogen pipeline could be less expensive than building new transmission lines and serve as a cost-effective way to transfer renewable energy to end users. A new hydrogen pipeline carries an amortized cost ($/MWh/1000 mi) of $5.0, while a new transmission line can be as much as $41.5.[123]

Additionally, hydrogen can be transported via trucking if the appropriate trailers[124] are available.[125] Trucks that haul gaseous hydrogen are called tube trailers. Gaseous hydrogen is compressed to pressures of 180 bar (~2,600 psig) or higher into long cylinders that are stacked on a trailer that the truck hauls. This gives the appearance of long tubes, hence the name tube trailer. Tube trailers are currently limited to pressures of 250 bar by U.S. Department of Transportation regulations, but exemptions have been granted to enable operation at higher pressures (*e.g.*, 500 bar or higher). Steel tube trailers are most commonly employed and carry approximately 380 kg onboard; their carrying capacity is limited by the weight of the steel tubes. Recently, composite storage vessels have been developed that have capacities of 560–900 kg of hydrogen per trailer. Such tube trailers are currently being used to deliver compressed natural gas in other countries.[126]

While hydrogen is two times more energy dense than methane on a mass basis, it is three times less energy dense than methane on a volume basis. Consequently, more volume of hydrogen is required for the same combustion power capacity when compared to methane. This requires the appropriate infrastructure to transport the hydrogen to combustion power plants and appropriate electricity generating units to be able to combust an increased volume. The limitation on the amount of hydrogen that can be safely mixed with natural gas weakens part of the pipeline network. Potential embrittlement of pipes leads to challenges, including additional methane leakage.

The production method and hydrogen delivery infrastructure both have an impact on the delivered price of hydrogen. Hydrogen transport by pipeline requires additional compression with energy penalties up to 20% of the energy required for compression. Additionally, trucking

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[121] Utility Dive (2022). *SoCalGas begins developing 100% clean hydrogen pipeline system*. Accessed at https://www.utilitydive.com/news/socalgas-begins-developing-100-clean-hydrogen-pipeline-system/619170/.
[122] Clean Energy Group (2020). *Hydrogen Projects in the US*. Accessed at https://www.cleanegroup.org/ceg-projects/hydrogen/projects-in-the-us/.
[123] Desantis, et al. (2021). Cost of long-distance energy transmission by different carriers. Accessed at https://doi.org/10.1016/j.isci.2021.103495.
[124] Gaseous hydrogen is frequently transported distances up to 200 miles with high-pressure cylinder and tube trailers at ~2,600 pound-force per square inch (psi).
[125] Goldmeer, J. (2019). *Power to Gas: Hydrogen for Power Generation*. General Electric (GE) Power. Accessed at https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.
[126] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Tube Trailers*, https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers

has shown to be a viable method of transporting hydrogen for distances of up to 200 miles. Trucking involves transporting hydrogen in high-pressure (*e.g.*, approximately 2,600 pound-force per square inch (psi)) tube-trailers, which is approximately twice the pressure of typical transporting pressures. Lastly, transport via ship may be another alternative for hydrogen transport. A pilot hydrogen transport ship in Japan was launched in 2019 with a storage capacity of 1,250 m^3, which is less than 1% of typical liquid natural gas carriers.[127]

The most cost-effective hydrogen transport method is largely dependent on the distance that hydrogen needs to be transported. It has been estimated that liquid carrier and truck transport of hydrogen are twice as expensive when transporting 1,000 km and more than 1.5 times as expensive when transporting 3,000 km. The cost of transport is roughly the same for hydrogen and hydrogen/natural gas blends via pipeline; however, transporting pure hydrogen is still slightly more expensive. The costs of pipeline hydrogen transportation of each are roughly \$0.05-2.00/kg H_2.[128, 129, 130]

The transportation method, and therefore cost, of hydrogen transport is largely dependent on the distance of transport. For example, transmission pipelines are useful for distances over 10 km for flows of over 100 tons per day (t/d). For comparison, distribution pipelines are mostly useful for distances up to 100 km of transport and volumes of between 10-100 t/d. The cost of transport for distribution pipelines can be anywhere from \$0.05-1.4/kg H_2 for reasonable distances. Trucks can transport hydrogen for long distances; although, for longer distances (~300 km or greater) will require liquid hydrogen trucks. Prices for compressed hydrogen trucks can range from \$0.55-0.75/kg for transports of 1-10 t/d, and prices for liquid hydrogen trucks can range from \$0.75-2.6/kg for transports of 1-10 t/d.[130]

Onsite hydrogen storage is used at central hydrogen production facilities, transport terminals, and end-use locations. Storage options today include insulated liquid tanks and gaseous storage tanks. The four types of common high-pressure gaseous storage vessels are shown in the table below.[131]

Type I	All-metal cylinder
Type II	Load-bearing metal liner hoop wrapped with resin-impregnated continuous filament
Type III	Non-load-bearing metal liner axial and hoop wrapped with resin-impregnated continuous filament
Type IV	Non-load-bearing, non-metal liner axial and hoop wrapped with resin-impregnated continuous filament

[127] U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.
[128] Note for the hydrogen/natural gas blend transport, this assumes extraction of hydrogen occurs at a low-pressure location.
[129] Di Lullo, G., Giwa, T., Okunlola, A., Davis, M., Mehedi, T., Oni, A. O., & Kumar, A. (2022). *Large-scale long-distance land-based hydrogen transportation systems: A comparative techno-economic and greenhouse gas emissions assessment.* International Journal of Hydrogen Energy. Volume 47, Issue 83, Pages 35293-35219. October 1, 2022. Accessed at https://www.sciencedirect.com/science/article/pii/S036031992203659X.
[130] Day, P. (2022). *Hydrogen uses to be determined by deliver methods*. Reuters. https://www.reuters.com/business/energy/hydrogen-uses-be-determined-by-delivery-methods-2022-10-12/.
[131] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *On-Site and Bulk Hydrogen Storage*, https://www.energy.gov/eere/fuelcells/site-and-bulk-hydrogen-storage.

Type I cylinders are the most common. Currently the costs of Type III and Type IV vessels are greater than those of Type I and II vessels. It is expected that with additional cost reductions in carbon fiber and improved manufacturing methods, these technologies could ultimately cost less than the traditional metal Type I cylinders. Cryogenic liquid storage tanks, also referred to as dewars, are the most common way to store large quantities of hydrogen. Super-insulated, low-pressure vessels are needed to store liquid hydrogen at -253 °C (-423 °F). The pressure of liquid hydrogen is no more than 5 bar (73 psig). Regardless of the quality of the insulation, however, some heat will reach the tank over time and cause the liquid hydrogen to boil.[132]

A national hydrogen infrastructure could require geologic (underground) bulk storage to handle variations in demand throughout the year. In some regions, naturally occurring geologic formations, such as salt caverns and aquifer structures, might be used, while in other regions, specially engineered rock caverns are a possibility. Geologic bulk storage is common practice in the natural gas industry and there are four existing salt caverns used for hydrogen storage today. The use of geologic storage for hydrogen used in fuel cell electric vehicles requires further investigation into the possible impurities that could be introduced by underground storage.[133] There are projects underway to test and demonstrate the technical, economic, and social viability of underground hydrogen storage.[134]

Hydrogen carriers, ideal for long-range transport, are hydrogen-rich liquid or solid phase materials from which hydrogen can be liberated on-demand. Ideal hydrogen carriers have high hydrogen densities at low pressure and near ambient temperature. The formation of the carrier and release of hydrogen from the carrier should be as energy efficient as possible to minimize the energy penalty associated with the use of the hydrogen carrier to store and transport hydrogen.[135]

There are two main categories of hydrogen carriers—two-way carriers and one-way carriers. A two-way carrier is a material that is transported to a distribution site in a “hydrogenated” form, dehydrogenated to yield hydrogen, and the dehydrogenated material returned to a processing site where it would be re-hydrogenated for reuse. Proposed two-way carriers include complex hydrides with high hydrogen capacities (e.g., $LiBH_4$) and some hydrocarbon systems, such as decalin-napthalene ($C_{10}H_{18} \leftarrow\rightarrow C_{10}H_8$).[136]

A one-way carrier would be decomposed at a distribution site to yield hydrogen and a byproduct that is environmentally benign and has no value. Its production should be cheap and efficient. Ammonia (NH_3) is being considered as one of the best potential options for a one-way carrier due to have a number of favorable attributes. Ammonia is one of the only materials that can be produced cheaply, transported efficiently and transformed directly to yield hydrogen and a non-polluting byproduct. Moreover, it has a high capacity for hydrogen storage (17.6 wt.%), based on its molecular structure. However, in order to release hydrogen from ammonia, significant energy

[132] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *On-Site and Bulk Hydrogen Storage*, https://www.energy.gov/eere/fuelcells/site-and-bulk-hydrogen-storage.
[133] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *On-Site and Bulk Hydrogen Storage*, https://www.energy.gov/eere/fuelcells/site-and-bulk-hydrogen-storage.
[134] IEA (2021), *Proving the Viability of Underground Hydrogen Storage*, IEA, Paris https://www.iea.org/articles/proving-the-viability-of-underground-hydrogen-storage.
[135] U.S. DOE EERE, Autrey, T. and Ahluwalia, R. (2018), *Hydrogen Carriers for Bulk Storage and Transport of Hydrogen*, https://www.energy.gov/sites/default/files/2018/12/f58/fcto-webinarslides-hydrogen-carriers-120618.pdf.
[136] US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.

input as well as reactor mass and volume are required. Other considerations include safety and toxicity issues, both actual and perceived, as well as the incompatibility of polymer electrolyte membrane (PEM) fuel cells in the presence of even trace levels of ammonia (> 0.1 ppm). Some turbine manufacturers are exploring the potential to combust ammonia directly in turbines potentially avoiding some of these issues.

Urea is also appealing since it doesn't suffer from the toxicity problems associated with ammonia, but its hydrogen content is only 9.1 wt% - a little over half that of ammonia. The potential utility of ammonia as a carrier for hydrogen delivery needs to be investigated and is currently under analysis by the DOE and the FreedomCAR & Fuel Partnership's Hydrogen Delivery Technical Team. Since a delivery system using ammonia would use existing technology, research in ammonia delivery should focus on analysis to better understand the economics and safety issues surrounding ammonia use. The ammonia cracking process needs to be improved. Better catalysts, efficient reactor designs, and inexpensive and reliable purification schemes all need to be developed if ammonia is to be used as a hydrogen carrier. It should be noted that some fuel cell technologies, such as alkaline fuel cells are ammonia tolerant, so extensive hydrogen purification would not be needed if they were fueled by hydrogen produced from ammonia. [137]

Ammonia distribution costs should be similar to LPG costs. Ammonia distribution would require additional safety equipment, but there are likely to be cost reductions if ammonia were distributed on scales approaching those of current gasoline distribution, so it seems reasonable to assume that these effects would offset each other, yielding similar costs. A recent TIAX study estimates LPG distribution costs to be around $0.55 per gasoline gallon equivalent (gge), including retail margins (Climate Friendly Alternative Fuel Vehicle Analysis, Stefan Unnasch & Jennifer Pont, TIAX LLC, Bluewater Network, July 15, 2004). Unpublished work from Oak Ridge National Lab estimates the cost at $0.54/gge including a retail margin of $0.18/gge. Converting the $0.36/gge cost of distribution equates to approximately $0.62/kg H_2 when distributed as anhydrous ammonia.[138]

Methanol can serve as a dense hydrogen carrier and can be generated using natural gas. At endpoints, methanol can easily be converted to syngas, a mixture of hydrogen and carbon oxides. In the near future, methanol may be created with more renewable feedstocks such as biogas which may yield higher potential GHG reductions during methanol production. There are eight methanol production plants using renewable natural gas currently operating and at least an additional 20 are expected in the next decade.

Research is being conducted on a fuel cell that can convert electricity into ammonia. By converting renewable electricity into an energy-rich gas that can easily be cooled and squeezed into a liquid fuel, these fuel cells effectively use solar and wind energy, turning them into a

[137] US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.
[138] US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.

commodity that can be shipped anywhere in the world and converted back into electricity or hydrogen gas to power fuel cell vehicles.[139]

Ammonia is emerging as the preferred international distribution mode for low-GHG hydrogen from GW-scale renewable power and electrolysis projects. Ammonia produced from natural gas and using CCS is still being explored. OCI N.V. plans to upgrade an aging natural gas-based hydrogen plant with CCS to produce ammonia, with 95% of the CO_2 emissions being captured and sequestered.[140] Methanol is another hydrogen derivative that is anticipated to enable low-GHG energy storage and possible energy exports. Liquid organic hydrogen carriers, liquid hydrogen, and compressed gaseous hydrogen shipping are also likely to increase.[141]

Truck or rail transportation of compressed hydrogen is very expensive. Liquid hydrogen tankers are cheaper, but there is a considerable energy and cost penalty associated with liquefaction (currently >30% of hydrogen's energy content is required to liquefy it). Distributed production will certainly play an important role, but the capital investment associated with small reformers may limit their utility. So other more cost-effective options are also being explored. The "wild card" option for distribution of centrally produced hydrogen is some sort of hydrogen carrier. A carrier is defined as a material, other than the H_2 molecule, that can be used to transport hydrogen. An additional requirement is that the transformation required to produce hydrogen from the material is relatively simple, uses little energy, and is low in cost. Note that materials such as methane or ethanol that can be reformed at a refueling station have strong chemical bonds between carbon and hydrogen and are considered raw material feedstocks for producing hydrogen rather than as hydrogen carriers.[142]

Another avenue for hydrogen use is the production of e-kerosene, a synthetic kerosene. Kerosene is largely used as fuel in the aviation industry. E-kerosene can be produced from the combination of CO_2 and hydrogen, and when the hydrogen is produced in a low-GHG manner, the carbon footprint of e-kerosene-based aviation fuels can be greatly reduced. It is estimated that the cost of e-kerosene production in the U.S. was $8.80 per gallon in 2020, but that it could decrease to $4.00 per gallon in 2050.[143]

Costs and Availability of Hydrogen

Cost Estimates Prior to the Inflation Reduction Act

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[139] Service, R. (2018), *Ammonia—a renewable fuel made from sun, air, and water—could power the globe without carbon*, https://www.science.org/content/article/ammonia-renewable-fuel-made-sun-air-and-water-could-power-globe-without-carbon.

[140] Business Wire (2022). *OCI N.V. Breaks Ground on 1.1 mtpa Blue Ammonia Site in Texas, USA.* Accessed at https://www.businesswire.com/news/home/20221207005572/en/OCI-N.V.-Breaks-Ground-on-1.1-mtpa-Blue-Ammonia-Site-in-Texas-USA.

[141] Harrison, S., *Transporting Hydrogen, Ammonia, and Methanol by Ship*, https://www.worldhydrogenleaders.com/courses/transporting-hydrogen-ammonia-and-methanol-by-ship.

[142] US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.

[143] Zhou, Y., Searle, S., Pavlenko, N. (2022). *Current and Future Cost of E-Kerosene in the United States and Europe.* Accessed at https://theicct.org/wp-content/uploads/2022/02/fuels-us-europe-current-future-cost-ekerosene-us-europe-mar22.pdf.

In 2017, commercial “at the pump” prices of hydrogen in California ranged from $13-15/kg H_2 for Fuel Cell Electric Vehicle consumers.[144] The transport costs of hydrogen to the refueling stations ranged from $6-8/kg H_2. If most of the hydrogen is produced via SMR (between $2-3/kg H_2), then the refueling stations’ costs contribute approximately $7/kg H_2.[145] However, the costs of hydrogen, including production and distribution, are expected to significantly decrease by 2030 as hydrogen infrastructure is scaled up. It is estimated that an increase from 20 to 80% hydrogen utilization rates in distribution can reduce distribution costs by up to 70%. Additionally, for non-transport applications, the delivered low-GHG hydrogen costs could drop by up to 90% as the supply chain is scaled up. The cost of low-GHG hydrogen production using renewable energy inputs could drop by 60% as the renewable energy generation costs decrease.[146]

As of 2020, 95% of domestic hydrogen was produced via SMR and 4% was produced via gasification.[147] SMR costs range from $2.08/kg to $2.27/kg with CCS, and coal gasification costs can range from $1.34/kg to $2.06/kg when using CCS. Other estimates for the cost of fossil fuel-fired hydrogen production (including SMR and coal gasification), estimate that the costs range from $1.0/kg without CCS to $1.5/kg with CCS.[148] The product costs for pyrolysis can be between 30 and 60% higher than SMR, resulting in costs of approximately $2.60/kg to $3.20/kg.[149] Currently only approximately 1% of hydrogen produced via SMR, coal gasification, or other similar methods included CCS.[150] The EPA expects that the tax subsidies in I.R.C. 45Q for the capture and storage of CO_2 will expand the use of CCS in the hydrogen production sector.

To date, the production of hydrogen via electrolysis remains limited and expensive compared to other production technologies; however, there are recent examples of technology developments with the potential to reduce these costs.[151] Some estimates of hydrogen costs for electrolysis ranged between around $5/kg to $6/kg when utilizing nuclear and wind electricity sources.[152] Other estimates indicate that hydrogen costs range from $8/kg to $11/kg, but that these costs can

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[144] Via California Hydrogen Business Council, FCEVs have twice the efficiency of conventional gasoline vehicles. One kg of hydrogen is the energy equivalent of one gallon of gasoline. Thus, for comparison, $10/kg H_2 is approximately equal to $5/gallon gasoline.
[145] Krishna, R., Amgad, E., Neha, R., Erika, G. (2017). *Impact of hydrogen refueling configurations and market parameters on the refueling cost of hydrogen.* United States: N. p., 2017. Web. doi:10.1016/j.ijhydene.2017.05.122.
[146] Hydrogen Council (2020). *Path to hydrogen competitiveness – A cost perspective*. Accessed at https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.
[147] U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.
[148] IEA, *The Future of Hydrogen Report* (June 2019), prepared by the for the G20, Japan. Accessed at https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.
[149] Sánchez-Bastardo, N., Schlögl, R., Ruland, H. (2021). *Methane Pyrolysis for Zero-Emission Hydrogen Production: A Potential Bridge Technology from Fossil Fuels to a Renewable and Sustainable Hydrogen Economy*. Ind. Eng. Chem. Res. 2021, 60, 32, 11855-11881. https://doi.org/10.1021/acs.iecr.1c01679.
[150] Zapantis, A. (2021). *Blue Hydrogen.* Accessed at https://www.globalccsinstitute.com/wp-content/uploads/2021/04/Circular-Carbon-Economy-series-Blue-Hydrogen.pdf.
[151] Bailey, Mary Page. (2022). *Iridium-free electrolysis demonstrated for stable hydrogen production*. Chemical Engineering. https://www.chemengonline.com/iridium/.
[152 152] U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.

be reduced to around \$6/kg by 2050.[153, 154] Specific to the electricity source, electrolysis production prices are estimated to be \$5.58/kg, \$5.96/kg, and approximately \$9.00/kg for nuclear, wind, and solar electrolysis, respectively.[155] Other estimates for electrolysis are similar; although, wind and solar electrolysis production prices have also been estimated to be as high as \$7.25/kg and \$8.30/kg, respectively.[156]

Some estimate hydrogen produced by electrolysis will cost less than \$2/kg H_2 in 2030[157] and other estimates predict \$3.1/kg H_2 production price in 2030 and \$2.7/kg H_2 production price in 2035.[158] Lastly, it has also been estimated that hydrogen produced by electrolysis may cost approximately \$1.30-2.30/kg H_2 by 2030.[159]

Technology innovation in the research stage could have a significant impact on future hydrogen systems as well. For example, engineers at RMIT University of Australia have employed sound waves to generate hydrogen via electrolysis more efficiently. The electrical output of electrolysis was about 14 times greater than electrolysis without sound waves and could potentially result in net-positive energy savings of 27%.[160] Additionally, researchers at Rice University developed a method to replace iridium with ruthenium, a much more abundant and less expensive material, in an electrolysis anode catalyst.[161]

Bringing lower cost, low-GHG hydrogen is already the aim of regional initiatives as well. The HyDeal initiative in Los Angeles is being implemented to deliver low-GHG hydrogen at under \$2/kg H_2 by 2030. This initiative brings together the entire value chain across the LA Basin, including production, transport, storage, and multi-sectoral aggregated offtake. The investment into the different facets involved in hydrogen production and delivery through the HyDeal over the next ten years is only expected to be a quarter of the status quo infrastructure spending for Southern California gas and electric utilities over the same time period.[162] Another prediction

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[153] Costs represent median prices of hydrogen.
[154] Christensen, A. (2020). *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe*. Accessed at https://theicct.org/wp-content/uploads/2021/06/final_icct2020_assessment_of-_hydrogen_production_costs-v2.pdf.
[155] U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.
[156] Ochu, E., Braverman, S., Smith, G., & Friedmann, J. (2021). *Hydrogen Fact Sheet: Production of Low-Carbon Hydrogen*. Accessed at https://www.energypolicy.columbia.edu/research/article/hydrogen-fact-sheet-production-low-carbon-hydrogen#_edn5.
[157] BloombergNEF (2021). *'Green' Hydrogen to Outcompete 'Blue' Everywhere by 2030*. May 5, 2021. Accessed at https://about.bnef.com/blog/green-hydrogen-to-outcompete-blue-everywhere-by-2030/.
[158] Zhou, Y., Searle, S., Pavlenko, N. (2022). *Current and future cost of e-kerosene in the United States and Europe.* March 2022. Accessed at https://theicct.org/wp-content/uploads/2022/02/fuels-us-europe-current-future-cost-ekerosene-us-europe-mar22.pdf.
[159] Heid, B., Sator, A., Waardenburg, M., & Wilthaner, M. (2022). *Five charts on hydrogen's role in a net-zero future.* October 25, 2022. Accessed at https://www.mckinsey.com/capabilities/sustainability/our-insights/five-charts-on-hydrogens-role-in-a-net-zero-future.
[160] Deena, T. (2022). *Engineers use sound waves to boost green hydrogen production by 14 times.* December 14, 2022. Accessed at https://interestingengineering.com/innovation/sound-waves-boost-green-hydrogen-production.
[161] Bailey, M. P. (2022). *Iridium-free electrolysis demonstrated for stable hydrogen production*. Chemical Engineering. December 1, 2022. Accessed at https://www.chemengonline.com/iridium/?oly_enc_id=3803F6418578H4X.
[162] Green Hydrogen Coalition (n.d.). *HyDeal Los Angeles*. Accessed at https://static1.squarespace.com/static/5e8961cdcbb9c05d73b3f9c4/t/6179eb9cf8ac24238842374d/1635380127410/HyDeal+LA+Phase+1+Takeaways.pdf.

estimated that under ideal conditions, by 2040, the delivered cost of hydrogen, which includes production, storage, and pipeline costs, can be under \$2/kg H_2 in several major cities. The transportation and storage cost are generally around \$0.5/kg H_2 in these scenarios.[163]

Infrastructure Investment and Jobs Act

In November 2021, Congress provided support for "clean hydrogen" in the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law (BIL). The law defined clean hydrogen as "hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced." The DOE released draft guidance of its "Clean Hydrogen Production Standard" (CHPS) for public comment in autumn 2022, which proposed setting a target for well-to-gate[164] emissions of 4 kg CO_2e/kg H_2 in hydrogen production.[165]

As part of the BIL, a federal investment is being made into domestic hydrogen infrastructure.[166] DOE is launching an \$8 billion program for developing clean hydrogen hubs (H2Hubs) across America. The intent of H2Hubs is to create a network of hydrogen producers, consumers, and resilient infrastructure to integrate hydrogen into the industrial sector, referred to as hydrogen hubs. Hydrogen production within these hubs can be powered by fossil fuels with CCS, nuclear, or renewable energy, and the DOE must distribute funds across at least four hubs from 2022 to 2026. Additionally, the BIL authorized \$1 billion for the Clean Hydrogen Electrolysis Program to reduce the cost of producing clean hydrogen to less than \$2/kg by 2026 and \$500 million for Clean Hydrogen Manufacturing and Recycling Initiatives to support hydrogen-related equipment manufacturing and build supply chains.[167] Ultimately, the aim is to drive down the cost of hydrogen production and transport and to produce more hydrogen with clean energy.

The DOE has a goal, named the "Hydrogen Shot", to reduce the clean hydrogen cost to \$1 per 1 kilogram of clean hydrogen in 1 decade ("111"). Lowering the cost of clean hydrogen will require innovation and investments in electrolysis technology using solar, wind, and nuclear energy.[168, 169] Reducing the costs of low-GHG hydrogen is a factor driving the DOE's strategic goal for 10 MMT of domestic clean hydrogen to be produced annually by 2030 followed by 20

[163] Energy + Environmental Economics (2020). *Hydrogen Opportunities in a Low-Carbon Future – An Assessment of Long-Term Market Potential In the Western United States*. June 2020. https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf.

[164] The well-to-gate analysis represents a subset of the cradle to grave analysis. The energy and emission associated with the manufacturing and recycling of the hydrogen production facility and the energy facilities used to power the hydrogen production facility are not considered.

[165] DOE (n.d.). *U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance*. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.

[166] The White House (2021). *President Biden's Bipartisan Infrastructure Law*. https://www.whitehouse.gov/bipartisan-infrastructure-law/.

[167] DOE (2022). *DOE National Clean Hydrogen Strategy and Roadmap*. Draft - September 2022. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.

[168] U.S. Department of Energy (DOE) (2022). *DOE Launches Bipartisan Infrastructure Law's \$8 Billion Program for Clean Hydrogen Hubs Across U.S.* Accessed at https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across.

[169] The 2021 Bipartisan Infrastructure Law aligns with DOE's Hydrogen Shot goal by directing the department to work to reduce the cost of clean hydrogen to \$2/kg by 2026. This goal is part of the \$9.5 billion in funding for research, development, and demonstration of clean hydrogen technologies and the creation of at least four regional clean hydrogen hubs. Significant projects in the U.S. include the Green Hydrogen Coalition's HyDeal Los Angeles (https://www.ghcoalition.org/hydeal-la) and the HY STOR project in Mississippi (https://hystorenergy.com/).

MMT and 50 MMT of annual clean hydrogen production by 2040 and 2050, respectively. As part of DOE's strategic goal, several key production targets are outlined, with many of them including electrolysis. Some of these targets include:[170]

- 1.25 MW of electrolyzers integrated with nuclear for H_2 production from 2022-2023.
- 10 or more demos with renewables (including offshore wind), and/or nuclear and waste/fossil with CCS from 2024-2028.
- 51 kWh/kg efficiency; 80,000-hr life; and $250/kW for low temperature electrolyzers from 2024-2028.
- 44 kWh/kg efficiency; 60,000-hr life; and $300/kW for high temperature electrolyzers from 2024-2028.
- 20 MW of nuclear heat extraction, distribution, and control for electrolysis from 2024-2028.
- 46 kWh/kg efficiency; 80,000-hr life; $100/kW uninstalled cost for low temperature electrolyzers between 2029-2036.
- 80,000-hr life $200/kW cost for high temperature electrolyzers while maintaining or improving efficiency between 2029-2036.

Inflation Reduction Act of 2022

The Inflation Reduction Act (IRA) was signed into law in 2022. Included in the IRA are expanded incentives for carbon capture and storage through 45Q tax credits. To qualify, power generation facilities, industrial facilities, and direct air capture (DAC) facilities must capture 18,750, 12,500, and 1,000 tonnes, of CO_2 annually, respectively. Additionally, power generation facilities must have a capture efficiency of no less than 75% to qualify. Tax credits differ depending on whether the captured carbon was stored or utilized and whether it is an industrial, power generation, or DAC facility.[171] Note that all qualifying projects must commence construction by 2033, and these tax credits may not be stacked with other tax credits.[165] Figure 6 outlines the tax credits for the varying scenarios.

Facility Type	Storage ($/tonne)	Utilization ($/tonne)
Industrial Facilities	85	60
Power Generation Facilities	85	60
DAC Facilities	180	130

Figure 65: IRA Carbon Capture Tax Credits ($/tonne) by Facility Type and Utilization/Storage Scenarios[172]

Additionally, the IRA explicitly expands 45D tax credits to include hydrogen fuel cells as an Energy Storage Technology with nameplate capacity of 5 kWh or greater. The tax credits expire December 2024 and transition to a fuel-neutral tax credit of up to 30%. Under the IRA, hydrogen facilities can receive direct pay options for the initial 5 years of the project. Note that the IRA

[170] DOE (2022). *DOE National Clean Hydrogen Strategy and Roadmap*. Draft - September 2022. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.
[171] Clean Air Task Force (CATF) (2022). *Carbon Capture Provisions in the Inflation Reduction Act of 2022*. Accessed at https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf.
[172] Clean Air Task Force (CATF) (2022). *Carbon Capture Provisions in the Inflation Reduction Act of 2022*. Accessed at https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf.

does not stipulate the emissions profile for hydrogen-based energy storage for tax credit eligibility.[173]

Lastly, the IRA offers qualified investments in hydrogen production through production tax credits (PTC) under Section 45V. There is a new 10-year PTC created by the IRA that provides tiered investments dependent on the well-to-gate GHG emissions of hydrogen production. At most, facilities can receive \$3.00/kg H_2, and the smallest tax credit available is \$0.60/kg H_2. The legislation stipulates that GHG emissions for consideration under this provision are estimated by the Greenhouse gases, Regulated emissions, and Energy use in Transportation model (GREET). Eligible projects for the hydrogen PTC can receive direct pay provisions, increasing the net value and fungibility of the tax credits. Figure 7 outlines the tax credits that can be claimed for different tiers of estimated GHG emissions from hydrogen production. Note that IRA projects have stipulations regarding prevailing wage and apprenticeship requirements to obtain maximum credit values.[174]

Carbon Intensity (CO_2e/kg H_2)	Max Hydrogen PTC Credit (\$/kg H_2)	Carbon Intensity (lb CO_2e/MMBtu)	Applicable Percentage of 45V Credit
0 - 0.45	\$3.00	0 – 7	100%
0.45 - 1.5	\$1.00	7 – 25	33.4%
1.5 - 2.5	\$0.75	25 – 41	25%
2.5 – 4.0	\$0.60	41 – 66	20%

Figure 76: Hydrogen Production Tax Credit Tiers by GHG Emissions in the Inflation Reduction Act

The impact of the IRA on hydrogen production and consumption is expected to be significant. One analysis estimated that the levelized cost of energy (LCOE) in 2030 for hydrogen will drop from \$200-275/MWh in a scenario without the IRA incentives to \$75-125/MWh following the IRA. For hydrogen production via electrolysis using renewable energy inputs, multiple incentives can be applied.

Cost Estimates Accounting for Provisions in the Inflation Reduction Act

Many of the cost projections for low-GHG hydrogen were developed prior to the incentives codified in the Inflation Reduction Act, including an incentive of up to \$3/kg for clean hydrogen production. A large determinant of the costs for hydrogen produced via electrolysis is the cost of renewable electricity. However, the investment in renewable energy technologies is driving down the cost of renewable electricity and of hydrogen produced via electrolysis. Other factors expected to reduce the cost of electrolysis include increased electrolyzer module sizes, increasing

[173] Clean Air Task Force (CATF) (2022). *Carbon Capture Provisions in the Inflation Reduction Act of 2022*. Accessed at https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf.
[174] DOE (n.d.). *U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance*. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.

stack production to automated production, alternative electrolyzer configurations with less costly materials, electrolysis system optimizations, and increased electrolyzer lifetimes.[175]

Some estimates anticipate that costs for clean hydrogen eligible for the IRA tax credits could approach negative pricing.[176] Other estimates of the impact that the tax credits provided by the IRA will have on hydrogen production have been released. High cost and low-cost technological scenarios were compared for hydrogen production via solar electrolysis and prices were compared for current policy and IRA scenarios. For both options, it was assumed that the IRA will result in a price which is lower by \$3/kg H_2. This results in hydrogen production prices of between \$0.39-1.92/kg H_2 for low cost and high cost hydrogen production technology, respectively.[177]

According to recent analysis by S&P Global Community Insights, the tax credits and subsidies included in the IRA could drive the price of low-GHG hydrogen to less than \$0/kg by 2030.[178] When the credits are stacked, the subsidy could equal \$4.50/kg H_2 produced, which means the cost of low-GHG hydrogen will be consistently less than the cost of hydrogen produced via SMR without CCS until the tax credits begin to expire in 2033. Credits for projects placed in service in 2032 will be eligible to receive credits for ten years thereafter. The primary reason for the low-GHG hydrogen cost advantage is that tax credits available for other production methods under the IRA cannot be stacked. S&P Global predicts this will drive further investments in the renewable energy sources necessary to produce low-GHG hydrogen, and in many instances, these renewable energy sources will be dedicated to powering electrolyzers.

US-REGEN Model

The U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) is an energy-economy model developed and maintained by the Electric Power Research Institute (EPRI) that includes an explicit representation of hydrogen production.[179] US-REGEN includes current projected future capital costs, fixed costs, variable costs, and efficiency information for multiple hydrogen production technologies. The EPA amortized the capital costs over 10 years for PEM electrolyzer and 12 years for the coal gasification and SMR with CCS at a 7% interest rate,[180]

[175] International Renewable Energy Agency (IRENA) (2020). *Green Hydrogen Cost Reduction – Scaling Up Electrolysers to Meet the 1.5ºC Climate Goal*. Accessed at https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf.
[176] Bowen, I., Madan, D., Rajwani, L., & Muthiah, S. (2022). *How clean energy economics can benefit from the biggest climate law in US history*. Accessed at https://www.icf.com/insights/energy/clean-energy-economic-benefits-US-climate-law.
[177] Larsen, J., King, B., Kolus, H., Dasari, N., Hiltbrand, G., & Herndon, W. (2022). *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act*. August 12, 2022. Accessed at https://rhg.com/research/climate-clean-energy-inflation-reduction-act/.
[178] Mulder, B. (2022). *US green hydrogen costs to reach sub-zero under IRA; longer-term price impacts remain uncertain*. Accessed at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/092922-us-green-hydrogen-costs-to-reach-sub-zero-under-ira-longer-term-price-impacts-remain-uncertain.
[179] https://us-regen-docs.epri.com/v2021a/assumptions/hydrogen-production.html#technology-cost-and-performance.
[180] The EPA amortized the capital costs over the number of years of the hydrogen production cand carbon storage tax credits.

used a natural gas price of $3.69/MMBtu, a coal price of $1.88/MMBtu, and an electricity price of $20/MWh to estimate the production costs of hydrogen. The EPA also applied the $3/kg H_2 production tax credit for the PEM electrolyzer, $0.7/kg H_2 CCS tax credit for the SMR, and $1.3/kg H_2 CCS tax credit for the coal gasification.[181] The EPA calculated the hydrogen production costs assuming a 40%, 60%, and 90% capacity factor for the PEM electrolyzer and 90% capacity factors for the SMR and coal gasification processes. Figure 8 shows the estimated hydrogen production costs.

Technology	**Year**			
	2025	**2030**	**2035**	**2040**
PEM (distributed. 40%)	2.0	0.9	0.3	(0.2)
PEM (distributed. 60%)	1.1	0.4	0.0	(0.3)
PEM (distributed. 90%)	0.0	(0.5)	(0.8)	(1.1)
SMR+99% CCS	1.4	1.4	1.4	1.4
Coal+90% CCS	0.6	0.6	0.5	0.5

Figure 87: Hydrogen Production Costs with IRA 45V and 45Q tax credits($/kg)

Coal gasification and SMR with CCS have similar hydrogen costs of $2.2/kg H_2 without considering available tax credits. Since coal gasification with CCS captures larger amounts of CO_2 than SMR, the tax credit has a greater impact on coal gasification and results in hydrogen production costs of less than $1/kg. At high capacity factors, the hydrogen production tax credit result in PEM derived hydrogen powered by zero-carbon energy at potentially negative production costs in 2030 and later years.

International Hydrogen Use

Hydrogen interest and utilization have been growing internationally. In 2021, global hydrogen demand reached 94 MMT, which was a 5% increase from 2020. Of the global hydrogen production, low-emission production accounted for less than 1% of the total production; however, the share of low-emission production grew by 9% from 2020 to 2021 and is projected to continue to increase. More than 200 MW of electrolyzers began operation in 2021, with 160 MW in China and 30 MW in Europe.[182]

Note that hydrogen production is expected to grow as governments and industry increase interest and investments in the sector. Globally, twenty-six governments have committed a hydrogen strategy to their energy system plans, with nine of those governments adopting a strategy within the past year. Global hydrogen targets include deploying an additional 145-190 GW of electrolyzer-produced hydrogen capacity. Based on global interest in hydrogen, it has been

[181] The carbon storage credit assumes 8 kg of CO_2 and 15 kg of CO_2 are captured from the SMR and coal gasification facilities respectively.
[182] IEA (2022). *Hydrogen*. Tracking Report – September 2022. Accessed at https://www.iea.org/reports/hydrogen.

estimated that hydrogen demand could reach 115 MMT by 2030; however, 130 MMT is needed to meet existing climate pledges in place by governments across the globe.[183,184]

[183] IEA (2022). *Hydrogen*. Tracking Report – September 2022. Accessed at https://www.iea.org/reports/hydrogen.
[184] IEA (2022). *Global Hydrogen Review 2022 – Executive Summary*. Accessed at https://www.iea.org/reports/global-hydrogen-review-2022/executive-summary.

United States
Environmental Protection
Agency

Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Electric Generating Units

EO 12866 Interagency Review

March 21, 2023

Internal, Deliberative – Do not quote or cite

Outline

- Regulatory History
- Overview of Proposed Requirements
  - New Source Performance Standards (NSPS)
  - Emission Guidelines
  - State Plan Development
  - Repeal of the Affordable Clean Energy (ACE) Rule
- Summary of Cost, Environmental, and Economic Impacts

Regulatory History

NSPS; CAA 111(b)

- In 2015, the EPA established greenhouse gas (GHG) standards for fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines
- In 2018, the EPA proposed to revise the NSPS but never finalized the proposal

Emission Guidelines; CAA 111(d)

- In 2015, the EPA finalized the Clean Power Plan (CPP) to address GHGs from existing electric generating units (EGUs)
- In 2019, the EPA repealed and replaced the CPP with the ACE rule
- In 2021, the D.C. Circuit Court vacated the ACE rule, which included the CPP repeal
- In 2022, the Supreme Court reversed the vacatur of the ACE rule and upheld the CPP Repeal

NSPS – Stationary Combustion Turbines

- Applicability date for NSPS is the date of proposal
- 40 CFR part 60, subpart TTTT (steam generating units and stationary combustion turbines)
- 40 CFR part 60, subpart TTTTa (stationary combustion turbines)

NSPS – Stationary Combustion Turbines

- Three general subcategories of stationary combustion turbines
  - Low load “peaking” turbines
  - Intermediate load turbines
  - Base load turbines

NSPS – Stationary Combustion Turbines

- **Low load** "peaking" units BSER and standards:
  - BSER: clean fuels
  - Standards of performance: 120 – 160 lb CO_2/MMBtu (depending on the clean fuel used)

- **Intermediate load** combustion turbines:
  - BSER has two components to be implemented in 2 phases:
    - 1st component of BSER: Highly efficient generation
    - 2nd component of BSER: Co-firing 30% (by volume) low-GHG hydrogen

  Phases:
    - 1st phase standards of performance: 1,150 lb CO_2 /MWh-gross – based on performance of a highly efficient natural gas-fired simple cycle turbine
    - 2nd phase standards of performance : 1,000 lb CO_2 /MWh-gross – based on performance of a highly efficient natural gas-fired simple cycle turbine co-firing 30% (by volume) low-GHG hydrogen
    - Standards would be higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2/MMBtu basis

NSPS – Stationary Combustion Turbines

- **Base load** combustion turbines:
  - 2 components to be implemented in 2 phases:
    - 1st component of BSER: Highly efficient generation
    - 2nd component of BSER: Either co-firing 30% (by volume) low-GHG hydrogen or 90% carbon capture and storage (CCS)
  - 1st phase standard of performance: 770 – 900 lb CO_2 /MWh-gross, depending on the base load rating – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine
    - Standard is higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2/MMBtu basis
  - 2nd phase standards:
    - Base load units combusting **less than 10% hydrogen**: 90 – 100 lb CO_2 /MWh-gross, depending on the base load rating – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine implementing 90% CCS
    - Base load units combusting **more than 10% hydrogen**: 680 lb CO_2 /MWh-gross – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine co-firing 30% (by volume) low-GHG hydrogen
    - Standard is higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2/MMBtu basis

Emission Guidelines — Steam Generating Units

- Existing fossil fuel-fired steam generating units – proposing emission guidelines covering these sources

- Existing fossil fuel-fired stationary combustion turbines – soliciting comment on emission guidelines covering these sources

- Applicability – follows from NSPS, includes coverage of sources in non-continental and non-contiguous states and territories

Emission Guidelines — Subcategories

- Proposes four subcategories for existing fossil fuel-fired steam generating EGUs, based on the operating horizon of the unit

  - Long-term EGUs – Units that have no commitment to cease operations prior to January 1, 2040

  - Medium-term EGUs – Units that have a binding commitment to cease operations prior to January 1, 2040

  - Near-term EGUs – Units that have a binding commitment to cease operations prior to January 1, 2035, annual capacity factor less than 20 percent

  - Imminent-term EGUs – Units that have a binding commitment to cease operations prior to January 1, 2032

Emission Guidelines — BSER and Degree of Emission Limitation

- Long-term Coal-fired Steam Generating Units
  - BSER: Carbon capture and storage with 90% CO_2 capture
  - Emission limitation: 88.4% reduction in emission rate
- Medium-term Coal-fired Steam Generating Units
  - BSER: co-firing 40% (by heat input) natural gas
  - Emission limitation: 16% reduction in emission rate
- Imminent-term and Near-term Coal-fired Steam Generating Units
  - BSER: Routine methods of operation and maintenance
  - Emission limitation: no increase in emission rate (presumptive standard of a unit-specific baseline)

Emission Guidelines — Natural Gas-fired Steam Generating Units

- Low load: < 8% annual capacity factor
  - BSER: None proposed, taking comment on a "clean fuels" BSER and presumptive standards on a heat input basis (*i.e.*, 120 lb CO_2/MMBtu)
- Intermediate load: 8-to-45% annual capacity factor
  - BSER: Routine O&M
  - Emission limitation: no increase in emission rate – a presumptive standard of 1,500 lb CO_2/MWh-gross
- Base load: ≥ 45% annual capacity factor
  - BSER: Routine O&M
  - Emission limitation: no increase in emission rate – a presumptive standard of 1,300 lb CO_2/MWh-gross

Emission Guidelines — Oil-fired Steam Generating Units

- Low load: < 8% annual capacity factor
  - BSER: None proposed, taking comment on a “clean fuels” BSER and presumptive standards on a heat input basis (*i.e.,* 160 lb CO_2/MMBtu)
- Intermediate load (continental): 8-to-45% annual capacity factor
  - BSER: Routine O&M
  - Emission limitation: no increase in emission rate (presumptive standard of 1,500 lb CO_2/MWh-gross)
- Base load (continental): ≥ 45% annual capacity factor
  - BSER: Routine O&M
  - Emission limitation: no increase in emission rate (presumptive standard of 1,300 lb CO_2/MWh-gross)
- Intermediate and base load (non-continental):
  - BSER: Routine O&M
  - Emission limitation: no increase in emission rate (presumptive standard of a unit-specific baseline)

Emission Guidelines — Existing Combustion Turbines

- EPA has an obligation to regulate GHG emissions existing combustion turbines because it has established NSPS for new combustion turbines
- EPA intends to fulfill that obligation as expeditiously as practicable, and as an initial step, is soliciting comments to inform the development of emission guidelines
- This action solicits comment on a potential staged approach in which an initial rulemaking would address the most frequently operated units and a later subsequent rulemaking would address the remaining units
- The first stage would focus on frequently operated turbines (*e.g.*, capacity factor of greater than 50% -60%) and would focus on ...
  - a BSER of CCS on a subset of these units and;
  - a BSER of heat rate (efficiency) improvements for the other units
- This approach recognizes the imperatives (the urgent need to reduce GHGs), the opportunities (including the availability of 45Q tax credits incentivizing CCS installation), and obstacles (the need for further development of infrastructure for CCS and co-firing low-GHG hydrogen)

State Plans for Proposed Emission Guidelines

- Compliance Deadlines
  - Proposing a compliance deadline of January 1, 2030

- Establishing Standards of Performance
  - Proposing a presumptively approvable methodology (or standard, where applicable); states would apply EPA's degree of emission limitation to a baseline emission rate for an affected EGU
    - Baseline: lb CO_2/MWh-gross from any continuous 8-quarter period within the 5 years immediately prior to the date the final rule is published in the *Federal Register*
  - Proposing increments of progress for medium-term and long-term subcategories, as well as requirements to report milestones related to ceasing operations for units with a federally enforceable commitment to cease operations (medium, near, and imminent-term subcategories)

State Plans for Proposed Emission Guidelines (cont’d)

- Remaining Useful Life and Other Factors (RULOF)
  - Relying largely on proposed subpart Ba, including threshold for invocation of RULOF (unreasonable cost, physical impossibility), with additional EG-specific provisions
  - Proposing that states must specifically demonstrate how they considered the health and environmental impacts on communities of a less stringent standard based on RULOF

- Compliance Flexibilities
  - Taking comment on whether trading and averaging are appropriate for use in state plans

- Components and Submission
  - Proposing to extend the state plan submission deadline from 15 months to 24 months
  - Proposing several requirements specific to these emission guidelines to ensure transparency, including a website hosted by EGU owners/operators to publish documentation and information related to compliance with the state plan

Repeal of the Affordable Clean Energy (ACE) Rule

- EPA is proposing to repeal the ACE rule on three grounds:
- Based on new developments and changed policies, EPA is changing its approach to BSER for existing coal-fired EGUs
  - ACE rule relied on Heat Rate Improvements (HRI), but they are not BSER because they would provide negligible CO_2 emission reductions overall and could lead to increases in emissions from some sources due to the rebound effect
  - CCS and co-firing natural gas are BSER because they are more impactful and are now cost-reasonable for certain sources due to technology development
- ACE rule did not provide the states with adequate guidance as to the level of emission reduction that their standards of performance must achieve
- ACE rule precluded states from complying using trading or averaging based on improper statutory interpretation

Summary of Cost, Environmental, and Economic Impacts

($Billions)

		3% Discount Rate	7% Discount Rate
Present Value	Climate Benefits	$30	$30
	Health Benefits	$77	$50
	Compliance Costs	$14	$10
	Net Benefits	**$93**	**$70**
Equivalent Annualized Value	Climate Benefits	$2.1	$2.1
	Health Benefits	$5.3	$4.8
	Compliance Costs	$0.95	$0.98
	Net Benefits	**$6.5**	**$5.9**

*Climate benefits are discounted at 3% in both the 3% and 7% discount case for other elements.

- Projected to result in national emission reductions of CO_2, SO_2, NO_X, and direct $PM_{2.5}$
- PV and EAV Analysis for 2024-2042 (2019$), using 3% and 7% discount rates
- The EPA has concluded the proposed rules will have no significant economic impact on a substantial number of small entities (no SISNOSE)

Power Sector Trends

Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

Docket ID No. EPA-HQ-OAR-2023-0072

U.S. Environmental Protection Agency

Office of Air and Radiation

March 2023

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Introduction

The purpose of this technical support document (TSD) is to review the recent historical trends shaping the electric power sector. For this TSD, electricity generation will be categorized across four primary fuel sources: nuclear, renewables (which include hydro, wind, solar, etc.), natural gas, and coal. There are other fuel sources for electricity, like petroleum, but these other sources represent less than 2% of annual generation.

In 2021, the majority of electricity came primarily from fossil fuel sources, with natural gas as the primary fuel source (at 37% of total generation), followed by coal-fired generation (22%). Most of the remaining electricity delivered to the U.S. came from low/zero emitting sources, including renewable and nuclear sources, at 20% each, and the remaining 1% of generation coming from other generating sources including petroleum.

In 2021, 43% of capacity was from natural gas fuel sources, 18% from coal, 25% from renewables, and 9% from nuclear. The differences in overall shares between generation and capacity are driven by the operation of the EGUs by fuel source and whether they have higher or lower capacity factors. For example, nuclear generation was 19% of generation, but only 9% of operating capacity at the end of 2021 because nuclear units typically operate at relatively higher loads (i.e., at higher capacity factors) as baseload units. Conversely generation shares are lower than capacity share for fuel sources like natural gas (38% and 43% respectively). Natural gas EGUs operate more flexibly and at lower capacity factors.

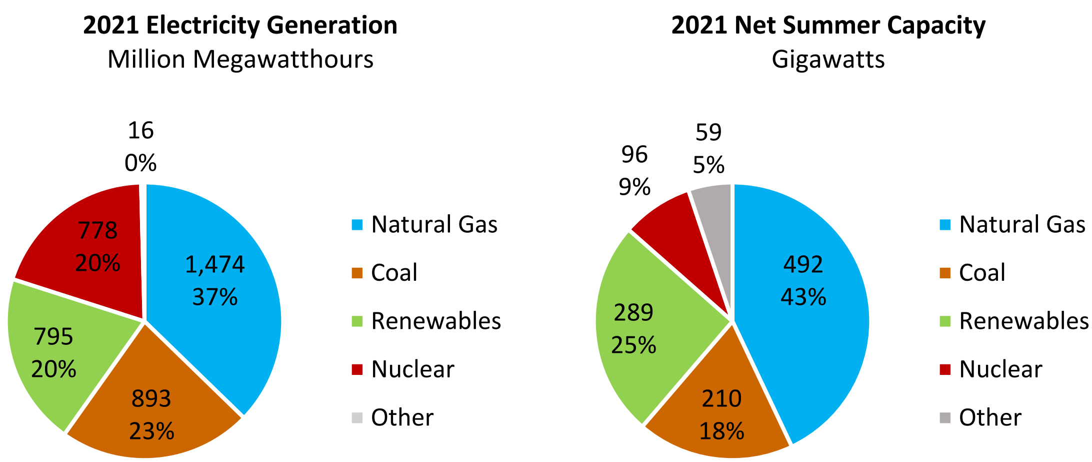

Figure 1: U.S. electricity generation and capacity shares by fuel type, 2021

Source: EIA, Monthly Energy Review, Table 7.2B Electricity Net Generation: Electric Power Sector, May 2022, www.eia.gov/totalenergy/data/monthly/, and EIA, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

Electricity generation from coal-fired EGUs has declined in recent years. Despite the fact that electricity demand has continued to increase over time, with total electricity generation increasing by 8% between 2000-2021, supply of electricity generation from coal-fired EGUs has declined by 54% over the same time period, starting at 1,943 GWh in 2000, peaking in 2007 at 1,998 GWh, and declining to 893 GWh by 2021. Coal-fired EGUs delivered 53% of total generation in 2000 and 23% in 2021. It's only within the last decade, starting in 2016, that coal generation was surpassed by another fuel source, natural gas. It's also expected that nuclear generation and renewable generation each will also surpass coal generation within the next year or so[1].

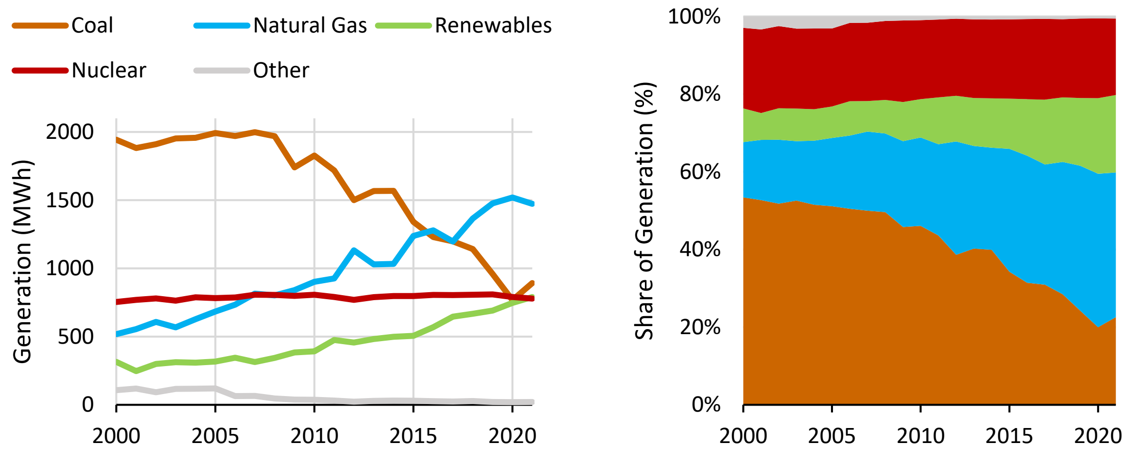

Figure 2: U.S. power sector generation and generation shares by fuel type, 2000-2021

Source: EIA, Monthly Energy Review, Table 7.2B Electricity Net Generation: Electric Power Sector, May 2022, www.eia.gov/totalenergy/data/monthly/

Generation from other sources, primarily natural gas and renewables, has replaced the declines in generation from coal. Generation from natural gas increased from 518 MWh in 2000 to 1,474 MWh in 2021. Generation from renewables increased from 315 MWh in 2000 to 790 MWh in 2021. The majority of the increase in renewable generation over that time period came from wind and solar.

This TSD uses recent historical power sector data, as well as an initial set of projections on the future outcomes of the electric power sector, to discuss the major trends occuring in the power sector. The following section begins with a brief background on power sector operations. The focus of power sector trends is then divided into two main sections: first, coal-related trends and the drivers that are leading to the decreases observed in coal capacity and operation and second, natural gas- and renewables-related trends and how they continue to increase to meet capacity and generation needs of the power sector. The final two sections of this TSD cover the state of other generating technologies in the power sector and concluding remarks.

[1] EIA, Short Term Energy Outlook, https://www.eia.gov/outlooks/steo/data.php

Power Sector Background

Electricity in the U.S. is generated by a range of technologies. The power sector consists of electricity generators that operate in interconnected grid systems, which are usually regional in scale. The electricity generated by these different technologies is transmitted and distributed through a system of interconnected components to end-users, e.g., industrial, business, and residential consumers.

Generation and capacity are commonly reported statistics with key distinctions. Generation is the production of electricity and is a measure of an EGU's *actual* output while capacity is a measure of the maximum *potential* production of an EGU under certain conditions. Capacity is typically measured in megawatts (MW) for individual units or gigawatts (1 GW = 1,000 MW) for multiple EGUs. Generation is often measured in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (1 GWh = 1 million kWh). Net generation is the amount of electricity that is available to the grid from the EGU and excludes the amount of electricity used within the power plant for operations (*e.g.*, ancillary services such as fuel handling equipment and environmental control equipment). In addition to producing electricity for sale to the grid, EGUs perform many services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators.

EGUs are not generally used to produce electricity 100% of the time. In fact, some EGUs only operate during the peak periods of highest demand (or constrained supply) while others are needed to meet daily and seasonal demand fluctuations. In general, the EGUs with the lowest operating costs are dispatched before EGUs with higher operating costs. As a result, an EGU with high fuel costs will typically only operate if other lower-cost plants are unavailable or if there is sufficiently high demand. Units are also unavailable during both routine and unanticipated outages. Unanticipated outages typically become more frequent as power plants age. The utilization of these EGUs is measured by their capacity factor. Capacity factors are calculated by dividing the actual amount of electricity produced by an EGU by the capacity times by the total number of hours within the year. For example, a capacity factor of 50% could mean that a generating unit is operating at full capacity half of the time or at half capacity all of the time.

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution. After generators produce their net generation for the grid, electricity is then transmitted over networks[2] of high voltage lines to substations where power is stepped down to a lower voltage for local distribution. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator;[3] in others, individual utilities[4] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

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[2] These three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those parts of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.*

[3] For example, PMJ Interconnection, LLC.

[4] For example, Los Angeles Department of Power and Water, Florida Power and Light.

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution systems are the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

During the past few decades, several jurisdictions in the U.S. began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by utilities separately from the generation of electricity and sometimes separately from the purchase and sale of electricity. Electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act (IIJA) (also known as the Bipartisan Infrastructure Law), which allocated more than $70 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-carbon fuels.

The Inflation Reduction Act (IRA), which President Biden signed on August 16, 2022, has the potential for even greater impacts on the electric power sector. With an estimated $369 billion in Energy Security and Climate Change programs over the next 10 years, covering grant funding and tax incentives, the IRA provides investment toward non GHG-emitting generation and away from the fossil fuel-fired units that are the subjects of these proposed regulations. For example, one of the conditions set by Congress for the expiration of the Clean Electricity Production Tax Credits of the IRA, found in section 13701, is a 75% reduction in GHG emissions from the power sector below 2022-levels.

The provisions in the IIJA and the IRA demonstrate a push to reduce GHG emissions through a broad array of additional tax credits, loan guarantees, and public investment programs. These provisions are aimed at reducing emissions of GHGs in the power sector from both new and existing generating assets.

Coal Trends

Coal-fired EGUs were once the primary source of electricity generation for the power sector; however, in recent years the delivery of electricity from coal has declined. Natural gas has surpassed coal-fired generation as the primary fuel source. Nuclear and renewable generation will likely surpass coal within the year.

Electricity from coal is delivered primarily through steam turbines that combust pulverized coal.[5] At a coal steam generating unit, the coal is crushed (pulverized) into a powder to increase its surface area. The coal powder is then blown into the combustion chamber of the boiler where it is burned.[6]

In 2021, there was a total of 208 GW of coal-fired capacity in operation. Of the remaining coal-fired EGUs the vast majority was built nearly half a century ago. The majority of coal-fired EGUs were installed in the 1970 and 1980 decades, with 102 GW and 69 GW installed respectively. Since 2000, only 21 GW of new coal-fired EGUs have been installed, or 8.5 times less than what was built over a similar time period from 1970-1990 (see Figure 3). Instead, utilities have opted to build new natural gas and renewable capacity. Over the same time-period of 2000-2021, 342 GW of new natural gas and 200 GW of new renewable capacity were installed, or over 25 times more capacity from new natural gas and new renewables as compared to new coal over the same time period (see Natural Gas and Renewables Trends Section).

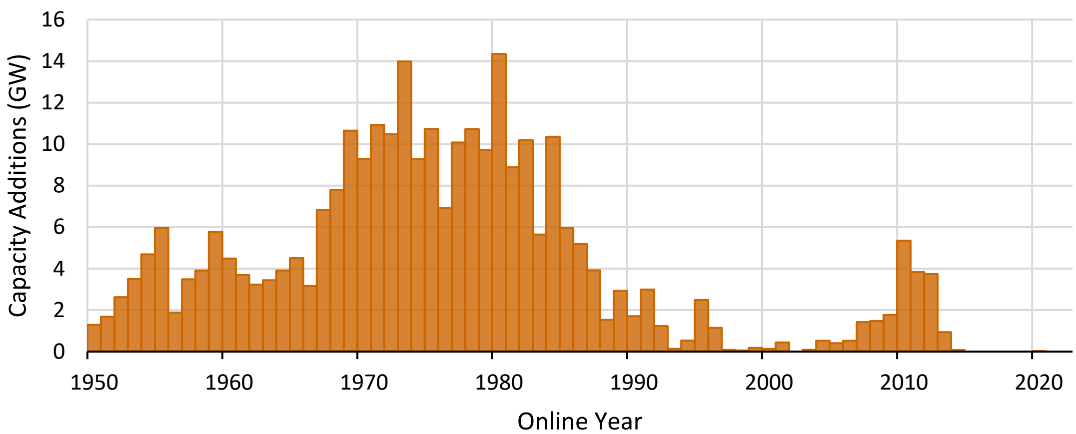

Figure 3: Annual capacity additions of coal, 1950-2021
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

It is unlikely that new conventional coal-fired EGUs will come online in the US. The last year in which a coal-fired EGU (greater than 25 MW) was built was in 2014. There are no new announced plans to build new coal-fired EGUs.

In addition to the lack of investment of new coal-fired EGUs, retirements of existing coal-fired EGUs have accelerated in recent years, both in absolute terms and in terms of the share of annual capacity retirements (see Figure 4). Between 2000-2010, 5 GW of coal-fired EGUs retired. Since 2010, 90 GW of coal-fired EGUs have retired. Coal represents the majority of all recent EGU retirements. For example,

[5] Fossil fuel-fired utility steam generating units (*i.e.*, boilers) are most often operated using coal as the primary fuel. However, some utility boilers use natural gas and/or fuel oil as the primary fuel.
[6] There are other, less common combustion technologies, for example, fluidized bed combustion technology. In fluidized bed combustion, the solid fuel is combusted in a layer of heated particles suspended in upward flowing air.

over the past five years, coal-fired EGUs have represented over half of all of the retired capacity in any given year. In 2022, coal-fired EGUs represented nearly 80% of all retired capacity (see Figure 4).

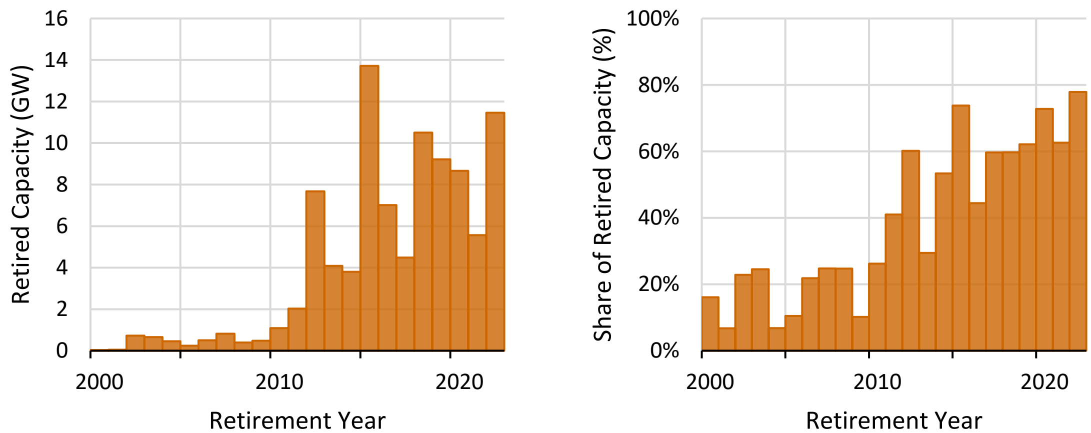

Figure 4: Annual coal retirements and retirement shares, 2000-2022
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

One driver for the observed increases in coal-fired EGU retirement is age. As mentioned earlier, the majority of coal-fired EGUs were installed in the 1970s and 1980s. With little capacity coming online over the past two decade, the average age of the coal-fired EGU fleet has increased over time. The capacity-weighted average age of operating coal-fired EGUs was 28 years old in 2000 and has increased to 43 years old in 2021 (see Figure 5).

As technology progresses, newer technologies coming online operate more efficiently and at lower costs than aging EGUs. The maintenance costs increase and the efficiency of EGUs declines over time as equipment degrades, further hindering cost competitiveness of older EGUs. The average lifetime of different EGUs varies by technology type and retirement decisions are not always motivated by the age of the asset.

The average annual retirement age for coal-fired EGUs for any given year between 2000-2021 was between 47 and 61 years old and the capacity-weighted average retirement age was 50 years (see Figure 6). Given that the average age of coal-fired EGUs in 2021 was 43 years old, this means that half of the operating coal fleet is at most within 7 years of the average age of retirement for coal-fired EGUs. Only 28% of operating coal capacity currently exceeds the average age of retirement.

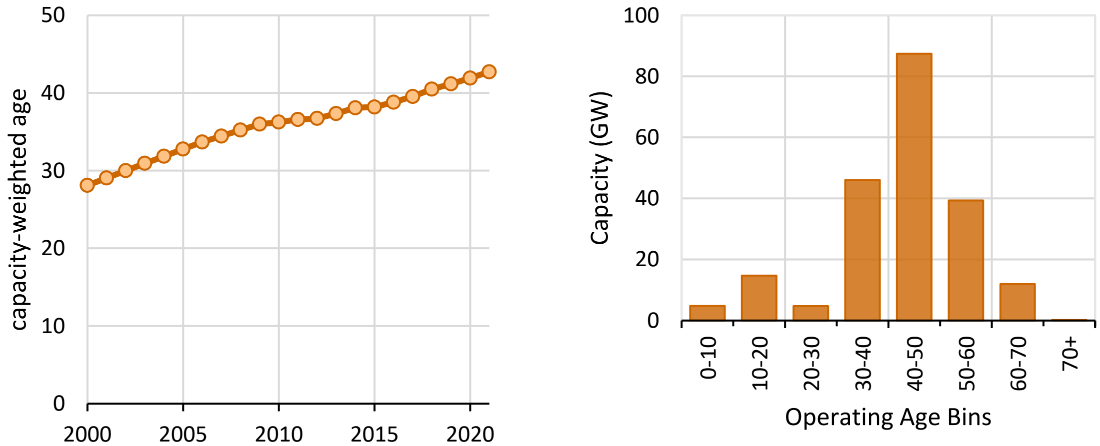

Figure 5: Coal age by operating year, 2000-2021, and total operating coal capacity by age bin, 2021

Source: EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/

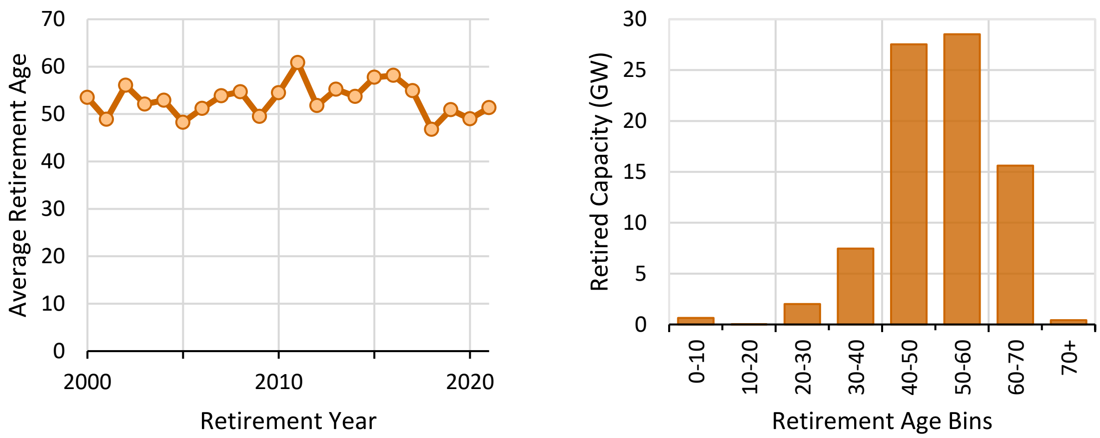

Figure 6: Coal retirement age by year, 2000-2021, and total retired coal capacity by age bin, 2000-2021
Source: EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/

Based on utilities' announced plans for coal-fired EGU retirements, this retirement trend is expected to continue. In 2021, there was a little over 200 GW of coal-fired EGUs operating in the power sector. Between 2021 and 2040, utilities have already announced publicly plans to retire a total of 118 GW of coal-fired EGUs, over half of the remaining coal fleet (see Figure 7).

Announced retirements are just one way to measure the future state of the power industry. Many utilities wait to publicly announce the retirement of a facility until its closer to their planned retirement date. Some utilities have announced broad plans to reduce operation of some of their coal-fired EGU fleet but haven't announced which facilities specifically will be the ones to retire by a given date. In either case, coal retirements are expected to continue, likely at a rate above that of announced retirements.

Beyond announced retirements, the age of the EGUs may be considered. In 2021, there were 10 GW of coal-fired EGUs operating on the grid with ages exceeding 50 years (e.g., the average coal-fired EGU retirement age) that did not already have an announced retirement. By 2040, there are an additional 60 GW beyond the 118 GW of coal-fired EGUs with announced retirements that would be at or above the age of 50. Assuming the coal-fired EGUs without announced retirements retire at the average coal retirement age (i.e. age-based retirement), that would lead to a total of 178 GW of coal retirements by 2040 or approximately 82% of the remaining coal fleet (see Figure 7).

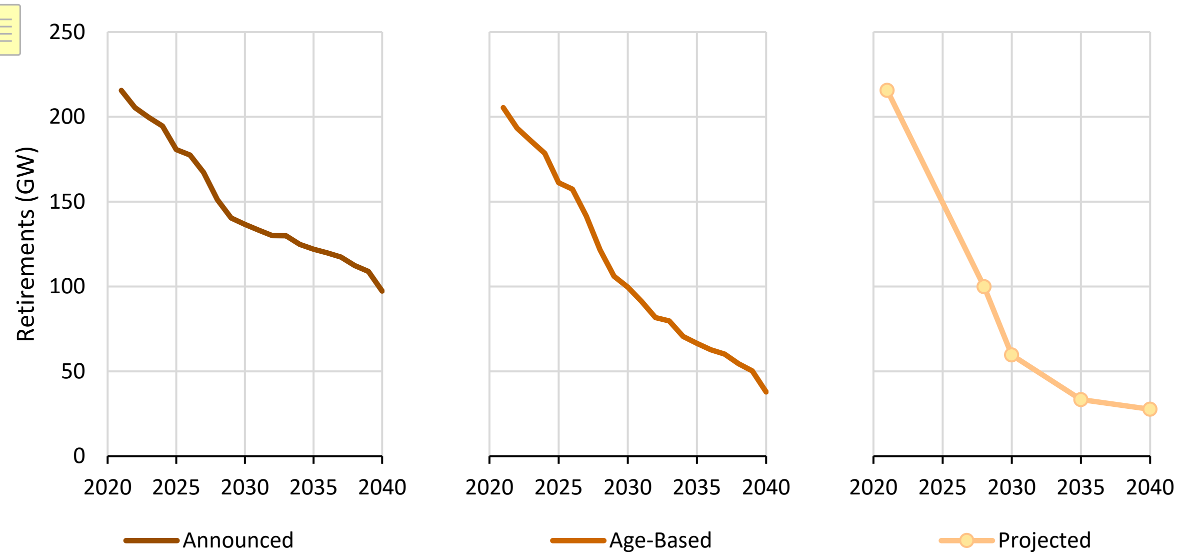

Figure 7: Coal capacity by category (announced, age-based, and projected), 2020-2040

Source: EPA, National Electric Energy Data System (NEEDS) v6, www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6 and EPA, Post-IRA 2022 Reference Case, www.epa.gov/power-sector-modeling

Another data source for coal retirements are model projections of the power sector . Power sector projections provide data out to 2050 on future outcomes of the electric power sector. The projections discussed here are based on a "business as usual" scenario, which includes representation of existing laws and regulations, including the IRA, but absent further proposed regulation. The results are based on EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case (i.e., Post-IRA 2022 Reference Case).

Power sector projections from the Post-IRA 2022 Reference Case show that coal capacity is expected to decline beyond announced retirements. The projections use announced retirements as an exogenous input into the model; the projections do not use exogenous age-based retirement assumptions. The additional projected retirements beyond the announced retirements are based on economic assumptions and other projected changes and suggest unfavorable market conditions for coal-fired EGUs going forward. Projections show a total of 187 GW of coal retirements by 2040 or nearly 90% of the remaining coal fleet (see Figure 7). Going forward, the provisions in the IRA, like the clean electricity tax credits, make the build out of lower emitting electricity generation more economically favorable than coal-fired generation.

Another driver for the decline in coal-fired generation over time is the decrease in the utilization of the operating fleet. Average coal-fired EGU capacity factors have declined over time as coal-fired EGUs have shifted from providing baseload power to, in many cases, providing intermediate power needs. Capacity factors for coal-fired EGUs were at 67% on average in 2005 and have fallen to a low of 41% in 2020 (see Figure 8). In 2021, there was a slight rebound in coal capacity factors, but overall coal capacity factors are expected to continue to decline. Looking at model projections of coal operation, by 2040, the Post-IRA 2022 Reference Case show coal capacity factors falling to an average of 10% across the remaining coal-fired EGU fleet.

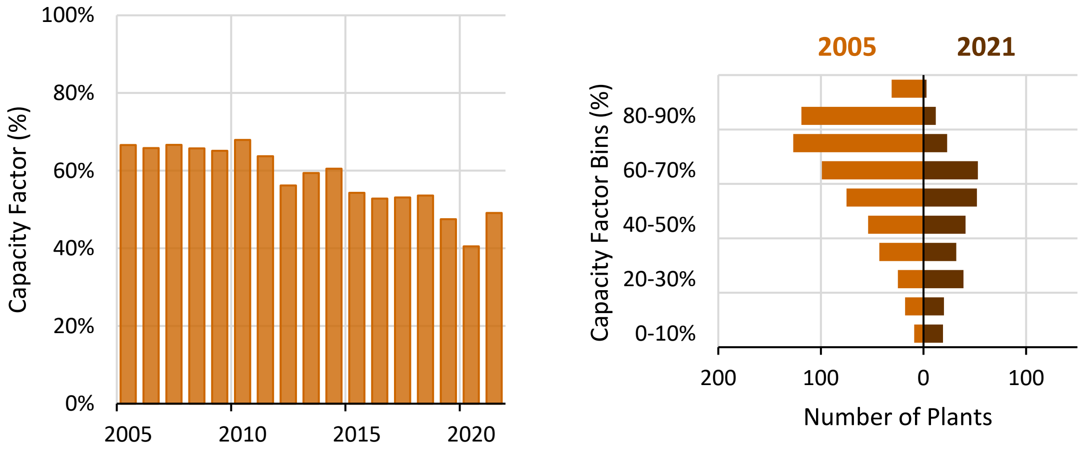

Figure 8: Coal average annual capacity factors and distributions, 2005-2021

Source: EIA, Electric Power Monthly, Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, September 2022, www.eia.gov/electricity/monthly/; EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/; EIA, Annual Power Plant Operations Report, Form EIA-923, October 2022, www.eia.gov/electricity/data/eia923/

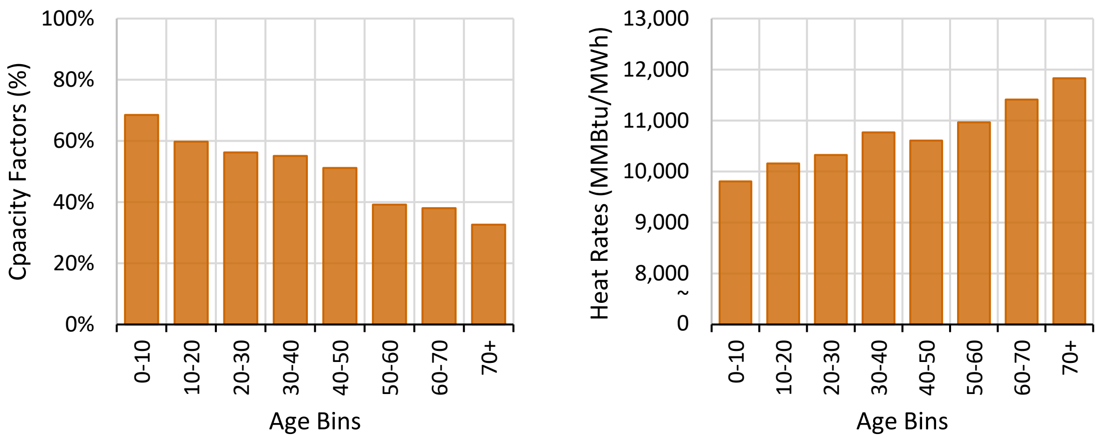

Figure 9: Coal capacity-weighted average annual capacity factors and heat rates by age, 2014-2021

Source: EIA, Annual Electric Generators Report, Form EIA-860, September 2022, www.eia.gov/electricity/data/eia860/ and EIA, Annual Power Plant Operations Report, Form EIA-923, October 2022, www.eia.gov/electricity/data/eia923/

One contributing factor to the decline in coal capacity factors is as coal-fired generators age, they tend to operate less and operate less efficiently. Between 2014-2021, younger coal-fired EGUs between the ages of 10-20 years operated at an annual capacity factor of 60% and at an annual heat rate of 10,159 MMBtu/MWh on average. Older coal-fired EGUs during the same period operated at lower capacity factors and higher heat rates, at 41% and 11,410 MMBtu/MWh on average for coal-fired EGUs between 60-70 years of age (see Figure 9). As mentioned previously (see Figure 5) the average age of coal-fired EGUs has increased from 28 years in 2000 to 43 years in 2021. And given the lack on new coal-fired EGUs coming online, this trend is expected to continue, suggesting that a decrease in capacity factors and a loss in efficiency will likely continue as well.

There are several factors that contribute to the loss in efficiency of coal-fired EGUs as they age. As coal-fired EGUs operate less often, they are often cycling more. Cycling coal-fired EGUs results in higher heat rates, as units are consuming more energy to produce electricity while the units are warming up. As heat rates increase, the emission rates of coal-fired EGUs also increase, since it takes more heat content (i.e., more tons of coal) to deliver the same amount of electricity.

Declines in coal-fired EGUs efficiency as they age also corresponds to declines in investment towards coal-fired EGUs as they age. Annual non-fuel operation and maintenance expenses were on average $43 for coal-fired EGUs between 30-50 years of age, based on data collected between 1994-2020. Annual operation and maintenance expenses decline as the EGUs age further, around $33 for EGUs between 50-70 years of age on average. In general, annual expense needs for EGUs do not decrease as the EGUs age, rather, the observed 23% decline over time more likely reflects shifting investment priorities.

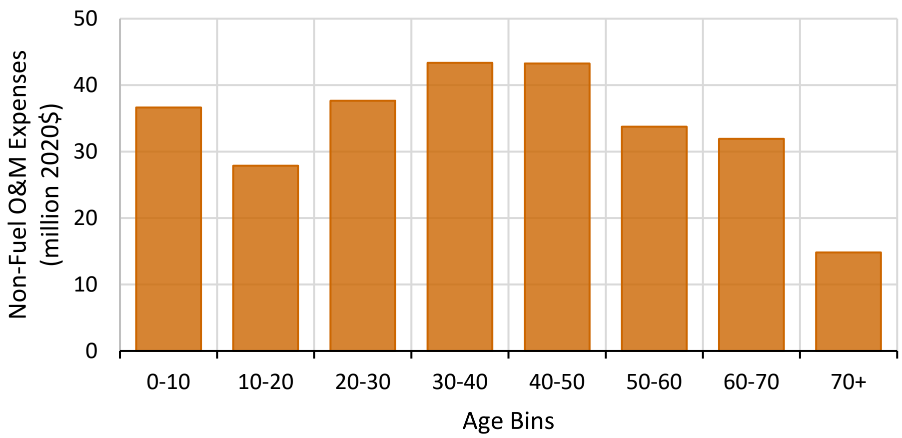

Figure 10: Coal capacity-weighted average annual non-fuel O&M expenses by age, 1994-2020
Source: FERC, Form No. 1 - Annual Report of Major Electric Utility, www.ferc.gov/industries-data/electric/resources/industry-forms/form-no-1-annual-report-major-electric-utility

Factors that contribute to the decline in capacity and operation of coal-fired EGUs are not limited to the trends discussed in this section, but also to the market conditions in which they operate. As natural gas and renewable technologies have declined in costs in recent years, more generation from these sources has entered the market, increasing competition. The following section will explore natural gas and renewable trends in more detail.

Natural Gas and Renewables Trends

Over the past two decades, natural gas generation has increased from 518 GWh in 2000 to 1,474 GWh in 2021 and renewable generation has increased from 315 GWh in 2000 to 790 GWh in 2021 (see Figure 11). This generation increase coincides with an increase in electricity demand as well as a decrease in electricity generation from coal-fired EGUs, as discussed in the previous section. Natural gas has surpassed coal-fired generation as the primary fuel source and renewable generation will likely surpass coal generation within a year.

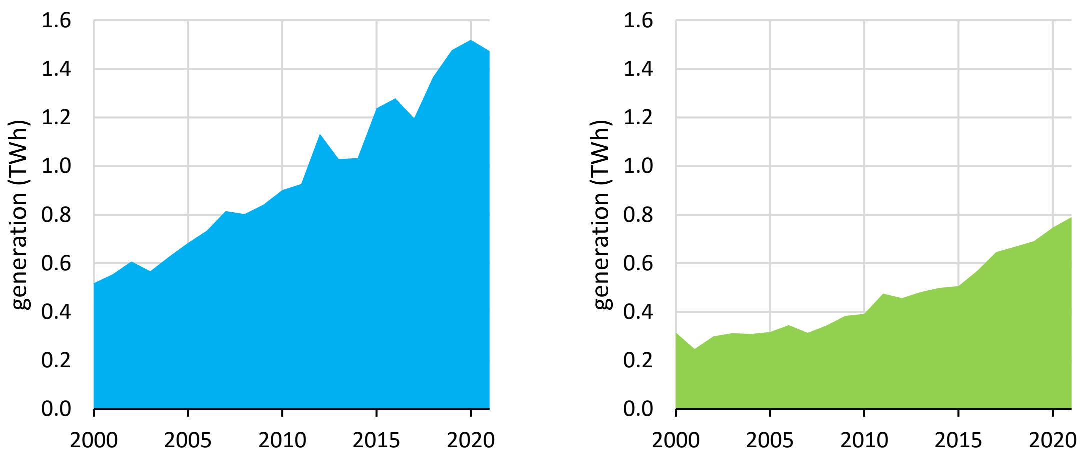

Figure 11: U.S. natural gas and renewable power sector generation, 2000-present

Source: EIA, Monthly Energy Review, Table 7.2B Electricity Net Generation: Electric Power Sector, May 2022, www.eia.gov/totalenergy/data/monthly/

The majority of natural gas consumption in the electric power sector comes from stationary combustion turbines, both simple cycle and combined cycle. Combustion turbines have the capability to burn either gaseous or liquid fossil fuels, although the majority of fuel consumption comes from natural gas. Natural gas can also be consumed at steam turbines (many existing coal- and oil-fired utility boilers have repowered as natural gas-fired units) and, to a lesser degree, internal combustion engines.

Stationary combustion turbine EGUs use one of two configurations: combined cycle (NGCC) or simple cycle combustion turbines (NGCT). NGCC units have two generating components (*i.e.*, two cycles) operating from a single source of heat, a combustion turbine and a heat recovery steam generator. Simple cycle combustion turbines only use a combustion turbine to produce electricity (*i.e.*, there is no heat recovery or steam cycle). NGCC units are more efficient and tend to operate at higher capacity factors; NGCTs are less efficient and are typically used only in times of peak electricity demand.

There has been significant expansion of the natural gas generation in recent years. Since 2000, natural gas generation has increased from 518 GWh in 2000 to 1,474 GWh in 2021. Between 2000 and 2021 there has been 242 GW of new NGCC capacity, 95 GW of new NGCT capacity, and 342 GW of new natural gas capacity in total. In 2021, the net summer capacity of natural gas EGUs totaled 413 GW, with 281 GW being NGCC generation and 132 GW being NGCT generation, with 69% of total natural gas capacity coming online since 2000 (see Figure 12).

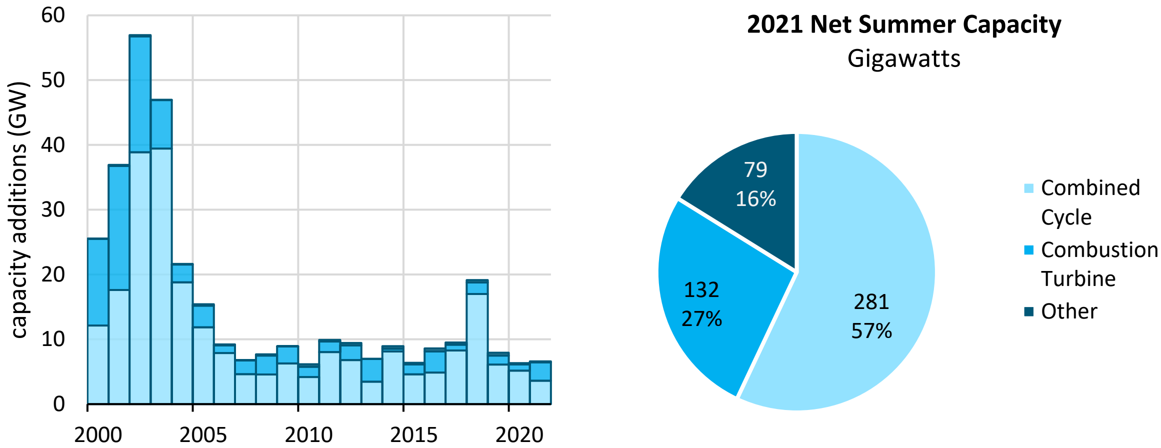

Figure 12: Natural gas capacity installed, 2000-2021, and 2021 share of natural gas capacity by type
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

The Post-IRA 2022 Reference Case projects that the majority of new builds of natural gas capacity will be from NGCT EGUs rather than NGCC EGUs. The reason model projections suggest an increased need of NGCT capacity going forward is due to the IRA increasing the deployment of new variable renewable electricity generation and the role NGCTs can play (along with other generating technologies, like energy storage) in balancing these variable renewable electricity resources.

Renewable electricity has also increased substantially in recent years and is expected to continue to grow. The Clean Electricity Production and Investment Tax Credits of the IRA provide financial support for new zero-emitting generation resources. These tax credits are available at full credit value to renewable generating technologies up until the later of 2032 or until there is a 75% reduction in GHG emissions from the power sector below 2022 levels. As these tax credits remain widely available, it is likely the expansion of renewable technologies will continue.

Renewable electricity is a broad category that represents a wide range of energy sources, including sources of energy from water, geothermal, biomass/waste, wind, and solar energy sources. Over the past two decades, renewable generation has more than doubled from 315 GWh in 2000 to 790 GWh in 2021 (see Figure 11). This recent growth in renewable generation is mostly attributed to changes in wind and solar generation.

Generation from water, geothermal, biomass/waste renewable resources have not substantially changed in recent years. The majority of conventional hydroelectric capacity was built before the 1980s. In 2021, hydroelectric capacity was at 80 GW and provided 33 percent of the net generation from U.S. renewables, which equates to approximately 7% of total net generation. Geothermal and biomass/waste energy sources combined grew in the 1980s and 1990s after the passage of PURPA[7], but haven't seen significant capacity growth in more recent years. In 2021, together these geothermal and biomass/waste renewable

[7] In 1978, partly in response to fuel security concerns, price spikes, and energy crises that affected the national and global economy, Congress passed the Public Utilities Regulatory Policies Act (PURPA). This legislation provided the impetus for renewable energy development because the act required local electric utilities to buy power from qualifying facilities (QFs). QFs were either cogeneration facilities or small generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels. See: Casazza, J. and Delea, F., Understanding Electric Power Systems, IEEE Press, at 220-221 (2d ed. 2010).

resources were at 15 GW of capacity and provided 6% of the net generation from U.S. renewables, which equates to approximately 1% of total net generation.

Since 2000, the majority of new renewable capacity coming online has been in the form of wind and solar capacity (see Figure 13). In 2021, wind provided 48% of renewable generation and 10% of total net generation and solar 14% of renewable generation and 3% of total net power sector generation[8].

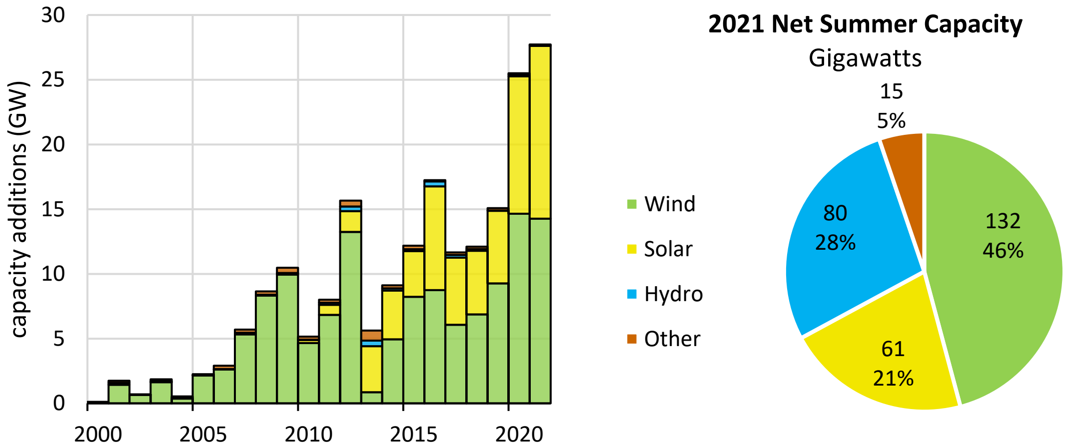

Figure 13: Renewable capacity installed, 2000-2021, and 2021 share of renewable capacity by type
Source: EIA, Electric Generators Inventory, Form EIA-860M, July 2022, www.eia.gov/electricity/data/eia860m/

Since the fuel sources for wind and solar technologies are essentially free, the main costs incurred by these technologies are in the upfront capital costs to build them. The capital costs of renewable energy sources have fallen over time. The unsubsidized average levelized cost of wind energy from 1988 to 1999 was $106/MWh and since declined to $32/MWh in 2021.[9] The average levelized cost of energy for utility-scale solar photovoltaics has fallen since 2010 from $227/MWh to $33/MWh in 2021.[10] As renewables' total O&M costs are relatively low compared to conventional generating technologies, like coal-fired EGUs that have fuel costs in addition to other O&M costs (see Figure 10), they are often ahead of coal-fired EGUs in the dispatch stack (i.e., the order in which EGUs generate). As more variable renewable energy technologies come online, they push dispatchable generating technologies, like coal-fired EGUs, further down the dispatch stack, leading to lower capacity factors for these conventional EGUs.

Projections of renewable capacity show continued increase, driven by declining costs and continued financial support though the provisions within the IRA. By 2040, projections from the Post-IRA 2022 Reference Case show renewable generation exceeding 60% of total generation.

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[8] The generation shares discussed here are based on power sector generation totals. There is also a significant amount of distributed solar generation from end-use sectors not accounted for here.
[9] U.S. Department of Energy (DOE), Land-Based Wind Market Report: 2022 Edition, 2022. See *https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition*.
[10] Lawrence Berkeley National Laboratory (LBNL), Utility-Scale Solar Technical Brief, 2022 Edition, September 2022. See *https://emp.lbl.gov/utility-scale-solar*.

Nuclear and Other Generating Technologies Trends

The previous sections discussed power sector trends related to coal, natural gas, and renewables. The remaining 19% of electricity generation is served by nuclear (19%) and other (1%) generation technologies. In 2021, there was a total of 96 GW of nuclear capacity operating on the grid and 59 GW of capacity from other generating technologies (see Figure 1).

Very little new nuclear capacity has come online since 2000[11] and there is little expected in terms of planned new builds. Historical trends show minimal change in nuclear capacity and generation in recent years. Nuclear capacity also received financial assistance through the IIJA and IRA that will likely enable the existing fleet to continue to operate through the end of the availability of the tax credits in 2032. The nuclear fleet is also aging and, like coal, may be impacted by changing market conditions after the availability of the tax credits expire. Most power sector projections show a decline in nuclear capacity post-2032.

There was a total of 59 GW of capacity from other generating technologies operating on the grid at the end of 2021, of which 30 GW came from fossil-fuel based resources (primarily petroleum products) and 28 GW came from energy storage technologies. In terms of, planned capacity additions, nearly all new capacity within the "other" category is expected to come from battery storage, a total of 21 GW of battery capacity to be install from 2022 to 2025.[12] The Post-IRA 2022 Reference Case also shows rapid growth in energy storage capacity, reaching 204 GW by 2040. Although energy storage technologies do not provide net generation to the grid, they do compete with conventional generating technologies, like coal-fired EGUs, that also contribute to capacity towards resource adequacy needs.

Conclusion

In 2021, 38% of generation was from natural gas, 23% from coal, 20% from nuclear, 19% from renewables, and 1% from other generating sources. Supply of electricity generation from coal-fired EGUs has declined by 54% between 2000 and 2021. Generation from natural gas and renewables has increased by 184% and 151% between 2000 and 2021, respectively.

The recent decline in coal generation has many contributing factors. The increase in coal retirements corresponds with increasing age, decreasing utilization, decreasing efficiency, and decreasing investment in non-fuel O&M costs seen across coal-fired EGUs. Outside of coal-related trends, the increases in generation from natural gas and renewables, as well as the increase in battery storage capacity, creates additional competition in the energy markets in which coal-fired EGUs participate. With added investment from IIJA and IRA, these trends are expected to continue in the future.

[11] https://www.eia.gov/todayinenergy/detail.php?id=26652
[12] https://www.eia.gov/todayinenergy/detail.php?id=54939

Efficient Generation: Combustion Turbine Electric Generating Units
Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

Docket ID No. EPA-HQ-OAR-2023-0072

U.S. Environmental Protection Agency

Office of Air and Radiation

March 2023

Table of Contents

Introduction

This technical support document describes the factors that impact the efficiency of both simple and combined cycle combustion turbines. It describes designs and operation and maintenance practices that can improve the efficiency of combustion turbines, which reduces fuel use and emissions of greenhouse gases.

As the thermal efficiency of a combustion turbine increases, less fuel is burned per gross megawatt of electricity produced by the turbine-generator and there is a corresponding decrease in carbon dioxide (CO_2) and other air emissions. Efficiency is reported as the percentage of the energy in the fuel that is converted to electricity. Heat rate is another common way to express efficiency. Heat rate is expressed as the number of British thermal units (Btu) or kilojoules (kJ) required to generate a kilowatt (kWh) of electricity. Lower heat rates are associated with more efficient power generation. Efficiency improvements can be expressed in different formats; they may be reported as an absolute change in overall efficiency (e.g., a change from 40% to 42% represents a 2% absolute increase). They may also be presented as the relative change in efficiency (e.g., a change from 40% to 42% is a relative change in efficiency and fuel use of 5%). The relative change in efficiency is the most consistent approach, since it corresponds to the same change in heat rate. For combustion turbine EGUs as a whole, as heat rates are reduced there are also reductions in fuel extraction related environmental impacts and in any associated thermal impacts on cooling water eco-systems.[1]

The electric energy output for an EGU can be expressed as either "gross output" or "net output." The gross output of an EGU is the total amount of electricity generated at the generator terminal. The net output of an EGU is the gross output minus the total amount of auxiliary (*i.e.*, parasitic) electricity used to operate the EGU (*e.g.*, electricity to power fuel handling equipment, pumps, fans, pollution control equipment, and other on-site electricity needs), and thus is a measure of the electricity delivered to the transmission grid for distribution and sale to customers.

Multiple design and operation and maintenance parameters influence the efficiency of a combustion turbine EGU. The following is a brief summary of some of the design parameters that impact the CO_2 emission rate of combustion turbine EGUs. This summary is not intended to be a comprehensive list of all design parameters that influence the CO_2 emission rate.

Combined cycle (CC) electricity generating units (EGUs) are power plants using both a combustion turbine engine (topping or Brayton cycle) and a steam turbine (bottoming or Rankine cycle) to generate electricity. Fuel is first burned in a combustion turbine engine, and the exhaust heat from the combustion turbine engine is recovered by a heat recovery steam generator (HRSG) to generate useful thermal output (e.g., steam). The steam is then used as the working fluid in a Rankine cycle and expanded through a turbine to generate additional power.[2] Combined cycles have significantly higher efficiencies compared to simple cycle combustion turbines—combustion turbine engines where the energy in the turbine exhaust is not recovered for a useful purpose.

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[1] Combined cycle EGUs using dry cooling or simple cycle EGUs do not have water eco-system impacts.
[2] https://www.ge.com/gas-power/resources/education/combined-cycle-power-plants

Potential Efficiency Gains at Simple Cycle EGUs

Simple cycle design has been iterated over the years to improve simple cycle efficiency, to increase capacity, and to reduce emissions. Efficiency improvements include increased firing temperatures, increasing compression rations, and the addition of intercooling. According to Gas Turbine world, the design net efficiency of simple cycle turbines range from 32 to 40%. These are design efficiencies at specified conditions, and both power output and efficiency are impacted by ambient conditions. In general, efficiency and output tend to decrease at higher ambient temperatures and increase at lower ambient temperatures. Several approaches are available to address both the loss in output and efficiency at higher ambient temperatures.

Efficiency and output of combustion turbines degrade as ambient temperatures increase. More specifically, ambient temperature is believed to reduce power output by 2.5% for every 10^{o}F above 59^{o}F.[3] To reduce the impacts of elevated ambient temperatures on simple cycle combustion turbines, owners/operators employ inlet air cooling techniques that generally fall in to two categories: evaporative cooling and chilling systems. Evaporative cooling works by adding liquid water to the combustion air. As the water evaporates, it cools the combustion air. Chilling systems use mechanical or adsorption chillers to reduce combustion air temperature.[4] One common type of cooling is inlet fogging, an evaporative cooling system. Inlet fogging works by spraying fine (typically < 20 microns) water particles into the inlet combustion turbine air, leading to lower inlet air temperatures and higher efficiencies.[5] A system like inlet fogging, but resulting in higher efficiency, is wet compression. Wet compression works by spraying an excess of fog into the inlet air, so that fog still exists after the air is fully saturated. Some of the excess fog droplets are not evaporated until they are carried into the compressor, which provides additional cooling. This results in further power increases of the combustion turbine engine.[6]

GE has its own intercooling technology, which it refers to as "SPRINT", or "SPray INTercooling". The SPRINT technology is paired with a LM6000 combustion turbine to its combustion air. More specially, demineralized water is atomized with high-pressure compressed air and sprayed into the inlet of the low-pressure compressor and high-pressure compressor. This results in a higher mass flow through the compressor and increased power output. Moreover, this technology can result in high incremental output and improved efficiency as ambient temperatures rise.[7] The design output and efficiencies for three different LM6000 combustion turbines with and without SPRINT technology are outlined in **Figure 1**.

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[3] GTW (2021). *2021 GTW Handbook.* Volume 36. Page 79. Pequot.
[4] United States Environmental Protection Agency (EPA) (2022). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units.* EPA Office of Air and Radiation. April 21, 2022. Accessed at https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf
[5] Meher-Homji, C., Mee, T. (2000). *Gas Turbine Power Augmentation by Fogging of Inlet Air*. Proceedings of the 28th turbomachinery Symposium (2000), Texas A&M. Accessed at https://oaktrust.library.tamu.edu/bitstream/handle/1969.1/163382/Vol28010.pdf?sequence=1&isAllowed=y.
[6] Savic, S., Hemminger, B., Mee, T. (2013). *High Fogging Application for Alstom Gas Turbines.* Proceedings of PowerGen. November 2013. Accessed at http://www.meefog.com/wp-content/uploads/High-Fogging-Alsotom-Mee_-2013-2.pdf.
[7] GE (n.d.) *SPRINT * SPray INTercooling for power augmentation*. Accessed at https://www.ge.com/gas-power/services/gas-turbines/upgrades/sprint.

FIGURE 1: COMPARISON OF LM6000 COMBUSTION TURBINES WITH AND WITHOUT SPRINT TECHNOLOGY

Gas Turbine	ISO Base Load (MW)	Efficiency (%)
LM6000 PC	46.6	40.0%
LM6000 PC Sprint	51.1	39.8%
LM6000 PG	56	39.1%
LM6000 PG Sprint	57.2	38.7%
LM6000 PF	44.7	41.4%
LM6000 PF Sprint	50.0	41.4%

Water injection is a process by which water is injected into the combustor and provides NO_x control. NO_x emissions from the combustor have been shown to increase exponentially with increasing temperatures. Thus, water injected into the combustor flame area to lower the temperature and, consequently, reduce NO_x emissions. Water injection is believed to result in a 60-80% reduction of NO_x emissions.[8] Additionally, experimental results have shown that water and steam injections can lower exhaust gas temperatures to reduce NO_x emissions by 70% and 57%, respectively.[9]

Steam Injection

Steam inject is similar to water injection, except that steam, instead of liquid water, is injected into the combustion chamber. The advantage of steam injection is that it improves the efficiency and increases the output of the combustion turbine as well as reducing NO_X emissions. Multiple vendors offer different variations of steam injection. The basic process is the use of a relatively low cost HRSG to produce steam. Instead of recovering the energy by expanding the steam through a steam turbine, the steam is injected into the combustion chamber of the combustion turbine and the energy is extracted by the combustion turbine engine itself. Combustion turbines using steam injection have characteristics in-between simple cycle and combined cycle combustion turbines. They are more efficient, but more complex and have higher capital costs than simple cycle combustion turbines without steam injection. Combustion turbines using steam injection and simpler and have lower capital costs than combined EGUs but have lower efficiencies.

A steam injection gas turbine cycle (STIG) is to the steam injection process used in GE combustion turbines. For STIG cycles, the steam source is specifically provided by the HRSG to increase both cycle efficiency and power output.[10] One study modeled the performance of a GE Frame 6b simple cycle that was retrofitted with a STIG cycle, and results suggest that efficiency can be increased from 30% to 40%

[8] EPA (2002). *CAM Technical Guidance Document.* B.17 Water or Steam Injection. Accessed at https://www3.epa.gov/ttnchie1/mkb/documents/B_17a.pdf.
[9] Kotob, M. R., Lu, T., Wahid, S. S. (2021). *Experimental comparison between steam and water tilt-angle injection effects on NO_x reduction from the gaseous flame.* Royal Society of Chemistry. 10.1039/D1RA03541J
[10] Bouam, A., Aissani, S., Kadi, R. (2019). *Gas Turbine Performances Improvement using Steam Injection in the Combustion Chamber under Sahara Conditions.* Oil and Gas Science and Technology. Institut Français du Pétrole (IFP), 2008, 63 (2), pp.251-261. 10.2516/ogst:2007076ff. ffhal-02001998f

and that power output can be increased from 38 to 50 MW.[11] The relative improvements suggested by this study are similar to estimates from GE. GE advertises that its LM2500 aeroderivative combustion turbine can have an improved power output by 25% when outfitted with a STIG cycle.[12] STIG uses constant pressure HRSG and operation is limited to near full load when thermal load is relatively constant. The exhaust temperature drops at partial loads and the HRSG cannot maintain a balanced heat transfer. While combined cycle EGUs have higher efficiencies than the STIG cycle, the STIG cycle is simpler and requires less capital.[13]

Mitsubishi Power's Smart-AHAT (Advanced Humid Air Turbine) is a steam injection system that achieves near zero water make-up using an integrated water recovery system. The system is potentially less complex and more flexible than combined cycle systems, with efficiencies significantly higher than conventional simple cycle plants. The HRSG involved in the system is a conventional single-pressure unit that produces the steam required for the combustion turbine steam injection. An important benefit of the Smart-AHAT system is water preservation. Without a water recovery system (WRS), water in the form of steam would exit the system through the HRSG stack leading to large amounts of water lost to the atmosphere. Smart-AHAT uses a direct, spray-type heat exchanger to reduce the HRSG exhaust gas temperature below the water dew point of the flue gas and cause condensation of the water vapor. Some condensate is recirculated to the spray nozzles of the heat exchange, while the rest if treated and returned as feed water for the HRSG steam production. Other benefits include reduced NO_X emissions and shorter construction cycles and lower costs than combined cycle plants.[14]

The Cheng Cycle provides more flexibility by using a variable pressure HRSG and the operating range is from idle to full load.[15] This approach provides the optimal heat recovery and steam injection capacity at a range of loads. Original performance measurements indicated the implementing a Cheng Cycle system on a combustion turbine can provide up to a 26% efficiency improvement compared to the base turbine engine.[16]

<u>Pressure Gain Combustion</u>

Pressure gain combustion (PGC) has the potential to increase combustion turbine power plant efficiency and reduce emissions. Estimates for higher efficiencies could reach 4-6% for simple cycle systems and 2-4% in combined cycle systems. In conventional combustion turbines, engines undergo steady, subsonic combustion which results in a total pressure loss. In PGC, multiple physical phenomena such

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[11] Wang, F. J., Chiou, J. S. (2002). *Performance improvement for a simple cycle gas turbine GENSET – a retrofitting example*. Applied Thermal Engineering 22 (2002) 1105-1115. Accessed at https://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.583.9680&rep=rep1&type=pdf.
[12] GE Power & Water. Accessed at https://www.ge-distributedpower.com/products/power-generation/15-to-35-mw/lm2500-stig/.
[13] Bahrami, S., et al (2015). *Performance Comparison between Steam Injected Gas Turbine and Combined Cycle during Frequency Drops*. Energies 2015, Volume 8. https://doi.org/10.3390/en8087582.
[14] Mitsubishi Power. *Smart-AHAT (Advanced Humid Air Turbine*. Accessed at https://power.mhi.com/products/gasturbines/technology/smart-ahat.
[15] Ganapathy, V., Heil, B., Rentz, J. (1988). *Heat Recovery Steam Generator for Cheng Cycle Application*. Industrial Power Conference, PWR, Vol. 4. Accessed at http://v_ganapathy.tripod.com/cheng.pdf.
[16] Digumarthi, R., Chang, C. (1984). *Cheng-Cycle Implementation on a Small Gas Turbine Engine*. Journal of Engineering for Gas Turbines and Power. Volume 106, Issue 3. https://doi.org/10.1115/1.3239626.

as resonant pulsed combustion, constant volume combustion, and detonation can be used to create a rise in effective pressure across the combustor while consuming an equal quantity of fuel.[17] The DOE assessed the inclusion of PGC in combined cycle power plants. The study found that a PGC integrated system produced 3.09% more power at the same fuel flow rate and reduced the cost of electricity (COE) by 0.58%.[18] One key advantage of PGC technology is that it can be compounded with other combustion turbine technology improvements such as compressor efficiency. Applications of PGC hold promise towards the Advanced Turbine Program's efficiency goals.[19] DOE's integrated PGC system achieved a net LHV efficiency of 64.56%, while a PGC system that included other combustion turbine technology improvements achieved a LHV efficiency of 66.68%.

[17] DOE NETL. *Pressure Gain Combustion*. Accessed at https://netl.doe.gov/node/7553.
[18] DOE (2016). *Combined Cycle Power Generation Employing Pressure Gain Combustion*. Accessed at https://www.osti.gov/servlets/purl/1356814.
[19] Neumann, Nicolai, & Peitsch, Deiter (2019). *Potentials for Pressure Gain Combustion in Advanced Gas Turbine Cycles*. Accessed at https://www.mdpi.com/2076-3417/9/16/3211.

Potential Efficiency Gains in Combined Cycle EGUs

Advances in Combined Cycle Operation

While many configurations of HRSGs are available to improve the steam bottoming cycle efficiency, several improvements have been made to other parts of the combined cycle. These include improvements to the combustion turbine engine, turbine cooling, compressors, condensers, and more. Improved performance in industry standard combined cycles has resulted from years of iterative industry innovation.

The evolution of GE gas turbines offers an example of the evolution of gas turbines over time to produce more efficient technology. GE currently offers 7HA and 9HA gas turbines, which run at 60 hertz (Hz) and 50 Hz, respectively. Both turbines are "H-class" technology, which include combustion turbines with firing temperatures greater than 1,430^{o}C. The H-class technology is the latest evolution of GE gas turbines that includes the E-class and F-class gas turbines as previous iterations. In general, the firing temperature has increased from the E-class (earliest iteration) to the H-class (latest iteration), and the resulting combined cycled efficiency has increased as well. In addition, the H-class gas turbines include entirely air-cooled hot gas paths due to advanced turbine cooling, sealing, materials, and coating. Within the 7/9HA gas turbines, the 7/9HA.01 turbines were the first iteration, and the 7/9HA.02 turbines came afterwards. The upgrade from the ".01's" to the ".02's" increased power output because of increased compressor inlet and turbine exit annulus areas, with an increased pressure ratio to maintain flow. It should be noted that the HA products can ramp to full plant load in less than 30 minutes, ensure ramping capability in emissions compliance of greater than 15 percent load per minute, and include fuel flexibility to operate on both gaseous and liquid fuels.[20] It should also be noted that a third generation 7HA gas turbine, 7HA.03, has been designed are even more efficient, and the first two GE 7HA.03 gas turbines have recently began operating at the Dania Beach Clean Energy Center (DBEC) in Broward County, Florida.[21] Combustion turbine combined cycle design specifications are outlined for the 7/9HA family in Figure 2.

FIGURE 2: DESIGN SPECIFICATIONS AT ISO CONDITIONS FOR THE GE 7/9 HA GAS TURBINE FAMILY[22]

Model	No. & Type Gas Turbine	Net Plant Output (kW)	Net Heat Rate (Btu/kWh)	Net Plant Efficiency (LHV)	Net Plant Efficiency (HHV)
9HA.01 (50 Hz)	1 x 9HA.01	680,000	5,356	63.7%	57.4%
9HA.01	2 x 9HA.01	1,363,000	5,345	63.8%	57.5%

[20] Vandervort, C., Leach, D., Scholz, M. (2016). *Advancements in H Class Gas Turbines for Combined Cycle Power Plants for High Efficiency, Enhanced Operational Capability, and Broad Fuel Flexibility.*8th International Gas Turbine Conference. 12-13 Oct. 2016. Brussels, Belgium. https://etn.global/wp-content/uploads/2018/09/ADVANCEMENTS-IN-H-CLASS-GAS-TURBINES-FOR-COMBINED-CYCLE-POWER-PLANTS-FOR-HIGH-EFFICIENCY-ENHANCED-OPERATIONAL-CAPABILITY-AND-BROAD-FUEL-FLEXIBILITY.pdf.
[21] Patel, S. (2022). *GE Debuts First 7HA.03 Gas Turbines at 1.3-GW Plant in Florida*. Power Magazine. Accessed at https://www.powermag.com/ge-debuts-first-7ha-03-gas-turbines-at-1-3-gw-plant-in-florida/
[22] GTW (2021). *2021 GTW Handbook.* Volume 36. Page 82-90. Pequot.

(50 Hz)					
9HA.02 (50 Hz)	1 x 9HA.02	838,000	5,320	64.1%	57.7%
9HA.02 (50 Hz)	2 x 9HA.02	1,680,000	5,306	64.3%	57.9%
7HA.01 (60 Hz)	1 x 7HA.01	438,000	5,481	62.3%	56.1%
7HA.01 (60 Hz)	2 x 7HA.01	880,000	5,453	62.6%	56.4%
7HA.02 (60 Hz)	1 x 7HA.02	573,000	5,381	63.4%	57.1%
7HA.02 (60 Hz)	2 x 7HA.02	1,148,000	5,365	63.6%	57.3%
7HA.03 (60 Hz)	1 x 7HA.03	640,000	5,342	63.9%	57.6%
7HA.03 (60 Hz)	2 x 7HA.03	1,282,000	5,331	>64.0%	>57.6%

Notice that small increases in net plant efficiency occur by collocating two gas turbines at one combined cycle plant.

Another advanced combustion turbine operating within combined cycle class is the Siemens HL gas turbine. The “HL” terminology intends to indicate that the current technology serves as intermediate between H-class technology and the L-class technology of the future which will be capable of 65% efficiency (LHV) when employed in a combined cycle plant. The HL combustion turbine evolved from the H-class turbine with some notable improvements. Namely, the turbine inlet temperature of the HL combustion turbine is about 100^{o}C higher than that of the H-class, which has a large impact on efficiency increase. Additionally, a new combustion system, called “Advanced Combustion system for high Efficiency” (ACE), is employed to reduce the increase in NO_x emissions resulting from the inlet temperature increase. Moreover, the number of compressor stages is reduced from 13 to 12, while simultaneously increasing the pressure ratio for increased performance and reduced complexity. Turbine blade internal cooling features were added to accommodate the higher temperatures, which also reduces dependency on cooling air consumption. Lastly, internally cooled free-standing blades are employed in stage 4 of the turbine, as opposed to uncooled blades in stage 4 for the H-class turbines, resulting in both higher power output and exhaust temperatures. Exhaust temperatures of the HL-class combustion turbine at designed to be around 680^{o}C, compared to 630^{o}C for Siemen’s H-class combustion turbine.[23]

Additionally, the U.S. Department of Energy’s (DOE) Advanced Turbines Program is supporting the development of advanced turbine technologies, which includes combined cycle. The program’s goal is reach 65% efficiency (LHV) for combined cycle technology by conducting research on hot section components and technology, including, but not limited to, materials, advanced cooling, leakage control, advanced aerodynamics, and altogether new turbine design concepts. Most notable, the program hopes

[23] Modern Power Systems (2018). *Siemens HL: the bridge to 65%+ efficiency*. Accessed at https://www.modernpowersystems.com/features/featuresiemens-hl-the-bridge-to-65-efficiency-6045386/.

to develop combustors to operate at higher temperatures with lower NO_x emissions.[24] More specifically, there is an aim to improve the firing temperature of combustion turbines in combined cycle plants to 3,100°F.[25] Furthermore, it should also be noted that the DOE cited combined cycle[26] efficiency goals of 67% (LHV) and "long-term" goals of 70% efficiency (LHV) in its 2022 fiscal year congressional budget request.[27] Combined cycle power plants employing Siemens HL-class technology are currently rated at >63% combined cycle efficiency, compared to 61% for those plants employing H-class technology.[28]

<u>HRSG Configurations</u>

The design of an HRSG can impact how long it takes to start producing steam and generating power. Currently, the most efficient combined cycle EGUs utilize HRSGs with a steam reheat cycle and multi-pressure steam. A steam reheat cycle extracts and reheats steam that has been partially expanded in the steam turbine prior to expansion in the lower pressure portion of the turbine. A reheat module allows more efficient operation of the steam turbine and prevents formation of water droplets that can damage the steam turbine's lower pressure stages. The use of three discrete steam pressures (high pressure (HP), intermediate pressure (IP), and low pressure (LP)) maximizes efficiency. Each of these three sections contains separate superheater, evaporator, steam drum, and economizer modules. The HP steam section is located on the high-temperature end of the HRSG, closest to the combustion turbine exhaust duct. The LP steam section is located on the low-temperature end of the HRSG, just before the stack. This arrangement maximizes the degree of superheat (*i.e.*, the quantity of energy per pound of steam) delivered to the steam turbine. Simpler, low-cost, less-efficient HRSGs are also available in single-, double-, and triple-pressure designs and without a reheat cycle. After the energy has been extracted for steam production, the flue gas enters an economizer, which preheats the condensed feedwater recycled back to the HRSG. The final heat recovery section, which is not used on all combined cycle EGUs, is the fuel preheater. The fuel preheater, which is not used in all combined cycle EGUs, preheats the fuel used for the combustion turbine engine.

While a HRSG has no moving parts, thermal inertia and rapid heating can stress the components of the HRSG and shorten the operating life of the unit.[29] The high-pressure drum is the most vulnerable component when subjected to rapid heating; therefore, the drum is typically heated slowly with designated hold points during startup.[30] While relatively inefficient, a dual-pressure HRSG without a reheat cycle has a simpler startup procedure and can start quicker than a more efficient triple-pressure HRSG with a steam reheat cycle. Also, an auxiliary boiler can maintain the HRSG temperature,

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[24] U.S. Department of Energy (DOE) (2021). *Advanced Turbines.* Accessed at https://netl.doe.gov/sites/default/files/2021-10/Program-108.pdf.
[25] DOE National Energy Technology Laboratory (NETL). *Advanced Combustion Turbines*. Accessed at https://netl.doe.gov/carbon-management/turbines/act.
[26] Efficiency using LHV for combined cycles using natural gas.
[27] DOE (2022). *Department of Energy FY 2022 Congressional Budget Request*. DOE/CF-0174, Volume 3 Part 2, Page. 199. Accessed at https://www.energy.gov/sites/default/files/2021-06/doe-fy2022-budget-volume-3.2_0.pdf.
[28] Gas Turbine World (2021). *2021 GTW Handbook.* Volume 36. Page 82-90. Pequot.
[29] Pasha, A. (1992). *Combined Cycle Power Plant Start-up Effects and Constraints of the HRSG*. Proceedings of ASME Turbo Expo, 1992. Power of Land, Sea, and Air. https://doi.org/10.1115/92-GT-376.
[30] Pasha, A. (1992). *Combined Cycle Power Plant Start-up Effects and Constraints of the HRSG*. Proceedings of ASME Turbo Expo, 1992. Power of Land, Sea, and Air. https://doi.org/10.1115/92-GT-376.

reducing the time required for an HRSG to begin producing steam. However, the use of an auxiliary boiler decreases the overall efficiency of the combined cycle EGU.

For HRSGs, there are currently three main configurations found in industry: 2-pressure non-reheat (2PNR), 3-pressure non-reheat (3PNR), and 3-pressure reheat (3PRH). The two-pressure (2P) versus three-pressure (3P) designations refer to the number of steam pressures in the steam cycle. 2P steam cycles employ two steam turbines—a low pressure (LP) steam turbine and a high pressure (HP) steam turbine. Similarly, 3P steam cycles employ three steam turbines, where one is an LP turbine, one is an HP turbine, and the third, located between the LP and HP turbines, is an intermediate (IP) pressure turbine. 2P and 3P cycles can also employ reheating as a method to increase steam turbine efficiency. With reheating, steam is routed back to the HRSG to be reheated prior to further expansion through subsequent lower pressure turbines.

A HRSG can also include duct burners, sometimes called supplemental firing. Supplemental firing is the mixing of additional fuel to turbine exhaust—which still contains available oxygen to support additional combustion. The combustion of this supplemental fuel increases the useful thermal output of the HRSG and is typically only done during periods of high electric demand. While the use of duct burners can increase output during critical periods, they reduce the overall efficiency of the combined cycle EGU. Since the additional fuel is only using the bottoming Rankine cycle, incremental efficiencies are on the order of a simple cycle combustion turbine. Typically duct burners are categorized as either small or large based on duct size, spacing and design constraints. Small duct burners are intended to make up capacity that is lost during period of high ambient temperatures. Small duct burners only impact efficiency while operating. In contrast, combined cycle designs with large duct burners oversize the steam turbine relative to the output that can be provided by the combustion turbine engine. The use of large duct burners provides significant additional capacity. However, since the steam turbine is more often operating at partial load and is less efficient, the combined cycle efficiency is impacted even when the duct burners are not operating.

An alternative to the use of duct burners is complementary firing. Complementary firing combines a relatively small combustion turbine(s)[31] with a larger combined cycle facility. The small turbine is generally used during periods when the steam turbine is not operating at capacity (*e.g.*, during periods of high ambient temperature that often correspond to periods of peak electric demand). The exhaust from the smaller turbine is sent to the HRSG of the combined cycle EGU. In essence, the smaller combustion turbine is a combined cycle EGU that is used for peaking applications. The benefits of complementary firing include that the incremental electricity is generated more efficiently than by using duct burners or from a stand-alone simple cycle turbine and the exhaust from the small combustion turbine is routed through the post combustion control technology of the larger combined cycle EGU. An additional advantage of complimentary firing compared to the use of duct burners is that since the majority of the incremental electricity is generated by the turbine engine, there is potentially less demand placed on the Rankine cycle portion of the larger combined cycle EGU. Drawbacks of complimentary firing compared

[31] The complimentary fired combustion turbine engines would be sized such that the turbine exhaust could be accommodated by the HRSG. This generally limits the size of the complimentary turbine engine(s) to less than 10% of the output of the primary turbine engine(s).

to the use of duct burners are higher capital costs, less fuel flexibility (duct burners can burn a variety of fuels), and more limited part-load performance.[32]

Potential Efficiency Gains in the Bottoming (Rankine) Cycle

The primary differences between a 2PNR, 3PNR, and 3PRH HRSGs are efficiencies and construction costs.[33] The complexity and cost increases with the number of steam pressures. However, increasing the number of steam pressures allows more energy to be extracted from the exhaust gas, improving overall efficiency. A reheat cycle adds additional complexity and capital costs but increases the efficiency of the Rankine cycle by increasing the average temperature of the heat addition within the process.[34] These capital costs can at least be partially offset by reductions in fuel costs. 2P and 3P HRSG without a reheat cycle have efficiencies of approximately 20 and 26%, respectively. A 3P HRSG with a reheat cycle improves the efficiency of thermal energy to electrical output to approximately 30%.

According to Gas Turbine World, all aeroderivative and frame combined cycles with base load ratings of less than 500 MMBtu/h use 2P HRSG. 3P HRSG without a reheat cycle are used for frame combined cycle EGUs up to 2,000 MMBtu/h, and 3P HRSG with a reheat cycle are used for frame combined cycle EGUs with base load ratings of greater than 2,000 MMBtu/h. From a practical standpoint, the use of a reheat cycle is limited to combustion turbines turbine engines with exhaust temperatures greater than 593 ^{o}C and for steam turbines greater than 60 MW.[35] However, 3P HRSG have been applied to aeroderivative combined cycle EGUs and could be adopted un smaller frame combined cycle EGUs as well.[36]

Several studies have compared various HRSG configurations for a combined cycle EGUs. One study directly compared 2PNR, 3PNR, and 3PRH steam cycles. It concluded that increasing the number of pressure cycles leads to an increase in efficiency of the whole cycle. Additionally, the study concluded that although increasing steam generation pressure levels requires a larger upfront investment, it ultimately yields a higher return, and the net present value (NPV) of the higher-pressure level plants (i.e., 3PRH) increases. The study concluded that the estimated net-present value of a 3PNR and 3PNR plant increase by 0.03% and 7%, respectively, when compared to that of a 2PNR plant.[37] Figure 3 shows the costs and efficiencies with more complex HRSG configurations compared to one with a 2PNR HRSG.

Figure 3: Relative Efficiencies and Costs of CC with Various HRSG Configurations

[32] In order to achieve part-load capabilities with complimentary firing multiple smaller turbines would be required.
[33] GTW (2021). *2021 GTW Handbook.* Volume 36. Pages 27-28. Pequot.
[34] Rashidi, M. M., Aghagoli, A., Ali, M., *Thermodynamic Analysis of a Steam Power Plant with Double Reheat and Feed Water Heaters*. Advances in Mechanical Engineering. Volume 2014, Article ID 940818, 11 pages. https://doi.org/10.1155%2F2014%2F940818
[35] Chase, D.L. and P.T. Kehoe, *GE Combined-Cycle Product Line and Performance*. GE Power Systems. GER-3574G
[36] https://www.ijert.org/off-design-performance-analysis-of-a-triple-pressure-reheat-heat-recovery-steam-generator
[37] Mansouri, M. T., Ahmadi, P., Kaviri, A. G., Jaafar, M. N. M. (June 2012). *Exergetic and economic evaluation of the effect of HRSG configurations on the performance of combined cycle power plants.* Energy Conversion and Management. Volume 58. Pages 47-58. https://doi.org/10.1016/j.enconman.2011.12.020.

HRSG Configuration	CC Net Efficiency	Increase in CC Efficiency Relative to 2PNR	CC Cost ($/kW)	Increase in CC Cost Relative to 2PNR
2PNR	56.06%	-	520.1	-
3PNR	56.22%	0.29%	530.5	2.0%
3PRH	57.15%	1.9%	540.6	3.9%

It should also be noted that single pressure HRSG technology is available as well. While they are the lowest cost and simplest HRSG design, they are also the least efficient and infrequently used in new combined cycle EGUs. The thermal efficiency of a single pressure, no reheat, HRSG system is estimated to be 3.7% less than that of a comparable 2PNR system.[38] One study estimated the efficiencies and electricity costs of single, dual, and triple pressure HRSGs. It found that, when compared to single pressure HRSGs, dual pressure and triple pressure HRSGs resulted in combined cycle efficiencies increasing by 4.5% and 7.2%, respectively. Moreover, the study estimated the cost of electricity from NGCCs utilizing single pressure, dual pressure, and triple pressure HRSGs to be $48.13/MWh, $46.39/MWh, and $45.79/MWh, respectively. According to this study, utilizing a dual pressure HRSG may result in a 3.6% electricity cost reduction compared to single-pressure HRSG utilization, and utilizing a triple pressure HRSG may result in a 4.9% electricity cost reduction compared to single-pressure HRSG utilization.[39] Figure 4 shows the costs and efficiencies with more complex configurations compared to one with a single pressure HRSG.

Figure 4: Relative Efficiencies and COE with Various HRSG Configurations

HRSG Configuration	CC Net Efficiency	Increase in CC Efficiency Relative to 1-pressure	Total Capital Requirement (TCR) (million $)	Increase in TCR relative to 1-pressure	COE ($/MWh)	Decrease in COE Relative to 1-pressure
1-pressure	50%	-	116.1	-	48.13	-
2-pressure	52.25%	4.5%	119.3	2.76%	46.39	3.62%
3-pressure	53.6%	7.2%	129.9	11.89%	45.79	4.86%

Heat Recovery Steam Generation Design Optimization

For a given HRSG design, parameters can be thermodynamically optimized to achieve the maximum overall efficiency. Optimization HRSG performance can identify a best-case scenario for which similar-designed HRSGs could be operated. Examples of design parameters include, but are not limited to, the pinch point temperature difference, inlet gas temperature, exit gas temperature, pressure within the turbine(s), mass flow rate, heat transfer area, pipe/tube/steam materials, condenser and cooling tower heat transfer surface area, steam turbine exhaust annulus area, external insulation to extract additional useful thermal output while maintaining the flue gas above the flue gas temperature, etc. Studies have both thermodynamically and economically optimized HRSG performance and development.

[38] Chase, D.L. and P.T. Kehoe, *GE Combined-Cycle Product Line and Performance*. GE Power Systems. GER-3574G
[39] Zhao, Y., Chen, H., Waters, M., Mavris, D. N. (2003). *Modeling and Cost Optimization of Combined Cycle Heat Recovery Generator Systems*. Proceedings of ASME Turbo Expo, 2003. Power of Land, Sea, and Air. https://doi.org/10.1115/GT2003-38568.

One study thermodynamically optimized parameters within HRSGs for single, double, and triple pressure turbine use. The results indicate that single-pressure, double-pressure, and triple-pressure HRSGs can increase combined cycle power output by 0.05, 0.28, and 0.29%, respectively, for every 10-bar inlet pressure increase. Furthermore, it found that the net combined cycle power output will decrease by 0.54, 0.21, and 0.17% for every 10°C evaporator pinch point temperature difference.[40] The results suggest that significant performance increase can result from choosing optimum operating conditions for a given HRSG. Additionally, the findings suggest that single-pressure HRSGs are most susceptible to efficiency decrement for suboptimum operation, and triple-pressure HRSGs have the most potential for improvement through optimization.

In addition, integrated fuel gas heating results in higher turbine efficiency due to the reduced fuel flow required to raise the total gas temperature to firing temperature. Fuel heating occurs before the fuel is fed into the combustion chamber of the combustion turbine and can be carried out by using the heat of the exhaust gases of the combustion turbine. Heating fuel gas from a base temperature of 0°C to a temperature of 450°C increases combustion turbine efficiency from 35.05 to 35.39%.[41]

Intercooled Combined Cycle

Intercooling is a concept that is being used in the latest combustion turbine systems. In simple cycle systems, intercooling is used to improve the overall efficiency and reduce the compression work by cooling the hot gases to atmospheric temperature. The energy of the hot water at the intercooler outlet is lost to the atmosphere. In a combined cycle combustion turbine this energy could be used to heat the feed water to the HRSG. In a combined cycle plant, the feed water entering the HRSG must have a higher temperature than the dew of the acid vapor of sulfur. The application of the intercooler as the feed water heater of the HRSG increases the overall efficiency of the combined cycle as it reduces the compression work in the upper cycle. An increase of feed-water temperature from 20 to 60°C could increase the overall efficiency by around 2%.[42]

Blowdown Heat Recovery

In NGCC plants, the concentration of impurities in the steam flow must be controlled to prevent corrosion of the steam turbine blades.[43] A portion of saturated water is continuously drained through boiler blowdown where it is discharged to the outside environment through a steam vent or drain flow. This process wastes energy and decreases the efficiency and net generated power of the cycle. Waste heat from the boiler blowdown stream can be recovered with a heat exchanger, a flash tank, or a

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[40] Rahim, M. A. (September 2012). *Combined Cycle Power Plant Performance Analyses Based on the Single-Pressure and Multipressure Heat Recovery Steam Generator*. Journal Of Energy Engineering. Volume 138, Issue 3. https://doi.org/10.1061/(ASCE)EY.1943-7897.0000063
[41] Marin, G. et al. (2020). *Study of the effect of fuel temperature on gas turbine performance*. Accessed at https://www.e3s-conferences.org/articles/e3sconf/abs/2020/38/e3sconf_hsted2020_01033/e3sconf_hsted2020_01033.html.
[42] Shukla, P., et al (2010). *A Heat Recovery Study: Application of Intercooler As A Feed-Water Heater of Heat Recovery Steam Generator*. Accessed at https://asmedigitalcollection.asme.org/IMECE/proceedings-abstract/IMECE2010/44298/611/357134.
[43] Saedi, Ali, et al (2022). *Feasibility study and 3E analysis of blowdown heat recovery in a combined cycle power plant for utilization in Organic Rankine Cycle and greenhouse heating*. Accessed at https://www.sciencedirect.com/science/article/pii/S0360544222019600.

combination of both.[44] In a flash tank, the pressure can be lowered to allow a portion of the blowdown to be converted into low-pressure steam which can be used in the cycle again as a heat source to preheat the feed water. The recovery of the wasted heat contributes to an increase in net power and energy efficiency of the Rankine cycle, as well as a reduction in annual water usage.[45] The usage of a flash tank could increase the net power and the energy efficiency of the Rankine cycle by 0.72% 0.23% respectively. Since about 1/3 of the output from a combined cycle is from the Rankine cycle, blowdown heat recovery could increase the output of the combined cycle EGU by 0.24% and the absolute efficiency by 0.077%.

Design and Operating and Maintenance Practices

While several state-of-the-art turbines and design alterations exist for new NGCC plants to maximize efficiency, efficiency can also be gained for existing NGCC by proper maintenance and reparations/reinstallation of various working components within a NGCC. All major manufacturers offer packages for plants to uprate, and these include improvements to seals, vanes, blades, and other materials within a plant. GE currently offers improved wire brush seals which can act as an alternative to both labyrinth seals for compressor shafts and high-pressure packing seals. Replacing the labyrinth and/or high-pressure seals can result in output increases of 1% and 0.3%, respectively, and heat rate increases of 0.5% and 0.2%, respectively. Moreover, advanced materials can reduce the need to cool turbine blades, or steam cooling of turbine blades can be used to recover the steam in a closed loop. Other options resulting in improvements for the power generation process include advanced coatings of turbine blades and combustor components, replacement of combustion liners, replacement of turbine vanes/blades, and inlet-air fogging.[46] **Figure 5** outlines the capacity and heat rate impacts and the corresponding capital costs for various turbine upgrades.

FIGURE 5: COMPARISON OF VARIOUS TURBINE UPGRADE OPTIONS[47]

Combustion Turbine Upgrade Option	MW Increase (%)	Heat Rate Impact (%)	Capital Cost ($/kW)[48]
Comprehensive Upgrade[49]	10-20	1-5	150-250
High-Flow Inlet Guide Vanes	4.5	1	<100
Hot Section Coatings	5-15	0.5-1	50-100
Compressor Coatings	0.5-3	0.5-3	50

[44] DOE (2012). *Recover Heat from Boiler Blowdown*. https://www.energy.gov/eere/amo/articles/recover-heat-boiler-blowdown#:~:text=Heat%20can%20be%20recovered%20from,occur%20with%20high%2Dpressure%20boilers.
[45] Vandani, Amin, et al (2015). *Exergy analysis and evolutionary optimization of boiler blowdown heat recovery in steam power plants.* Accessed at https://www.sciencedirect.com/science/article/pii/S0196890415008535.
[46] Andover Technology Partners (2018). *Improving Heat Rate on Combined Cycle Power Plants*. Accessed at https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.
[47] Andover Technology Partners (2018). *Improving Heat Rate on Combined Cycle Power Plants*. Accessed at https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.
[48] Costs shown in 2002 dollars.
[49] May include "replacement of combustion liners, transition pieces, 1st stage turbine vanes, and 2nd stage vanes and blades with [GE] Frame 7EA parts."

Inlet-Air Fogging	5-15	1-5	50-100
Supercharging Plus Fogging	15-20	4	200

Proper cleaning of HRSG components can also have worthwhile impacts on turbine performance as it can maintain low pressure drop across the HRSG. Various contaminants, most notably ammonium bisulfate, can accumulate in the HRSG which can produce pressure losses. In one case study on HRSG cleaning, GE removed 14 tons of debris, resulting in a reduced turbine back pressure of 8 inches water column. The combined annual fuel savings and additional power output are believed to have netted the facility $500,000/year in avoided costs/additional revenue.[50] Similarly, plant condensers should be regularly cleaned. Airborne dust and debris can regularly accumulate and degrade condenser performance.[51] Note that turbine overhauls can range from $2-$12 million for 200 MW turbines but could provide heat rate improvements of 100-300 Btu/kWh, which represents around 1-3% of the steam cycle. Additionally, proper O&M practices can reduce heat rates by around 30-70 Btu/kWh (~0.3-0.7% of steam cycle) for cost of $30,000 annually, and feed pump rebuilds can improve the steam cycle heat rates by 0.25-0.5% for costs of $250,000-$350,000.[52,53]

As it relates to the steam system, there are several operational practices which can reduce the heat losses within the system. Some of these methods are outlined as follows[54]:

- Minimize air-in leakage
- Clean HRSG heat transfer surfaces
- Improve water treatment to minimize HRSG blowdown
- Recover energy from HRSG blowdown
- Add/restore HRSG and steam plant insulation
- Optimize deaerator vent rate
- Repair steam leaks
- Minimize vented steam
- Ensure that steam system piping, valves, fittings, and vessels are well insulated
- Implement an effective team-trap maintenance program
- Isolate steam from unused lines
- Optimize condensate recovery
- Clean combustion turbine flow path components

Once Through (Benson®) HRSG Technology

[50] GE (2017). *When is 28,000 pound pile of rust a good thing?*. Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/services/hrsg-services/pressurewave-case-study.pdf.
[51] Andover Technology Partners (2018). *Improving Heat Rate on Combined Cycle Power Plants*. Accessed at https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.
[52] Costs given in 2008 dollars.
[53] Sargent & Lundy (2009). *Coal-Fired Power Plant Heat Rate Reductions*. SL-009597. Final Report. Accessed at https://www.epa.gov/sites/default/files/2015-08/documents/coalfired.pdf.
[54] Andover Technology Partners (2018). *Improving Heat Rate on Combined Cycle Power Plants*. Accessed at https://www.andovertechnology.com/wp-content/uploads/2021/03/C_18_EDF_FINAL.pdf.

The use of a once-through (i.e., Benson®) HRSG can also improve the ability of a combined cycle EGU to start quickly and maintain efficiency at part load. A once-through HRSG does not have a steam drum like a more traditional HRSG. Instead, the feedwater is converted to steam in the HRSG furnace waterwalls and goes directly into the steam turbine. This allows for the use of higher-pressure steam, which improves design efficiencies, provides higher part-load efficiencies, allows reduced startup times, and results in more flexible operation.

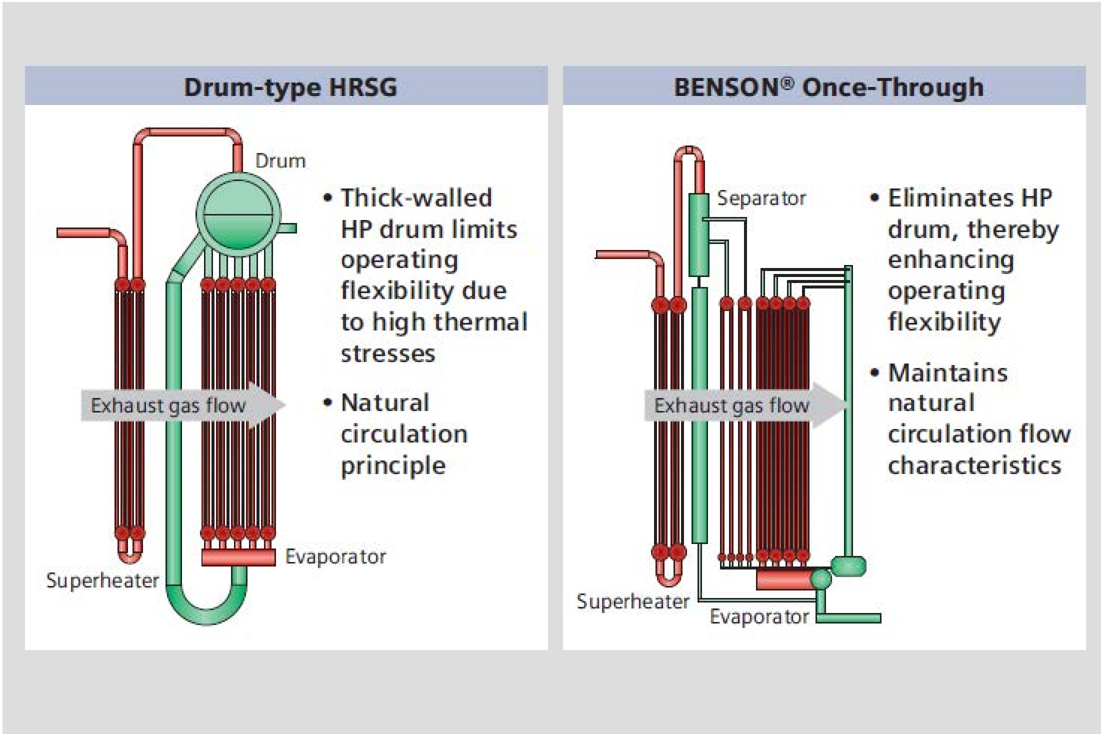
The Benson Technology is touted as "a proven process for large-scale steam generation in power plants with the heart of this process being the once-through principle. Combined with sliding pressure operation, this allows for highly efficient, flexible, and reliable power plant operation".[55]

Advantages of the Benson Once-Through HRSG[56]55

- It retains all the virtues of the proven natural circulation principle of drum-type boilers (*i.e*. flow stability and uniform temperature distribution), yet at the same time replaces the high-pressure drum with thin-walled components to improve operating flexibility.
- Significant shortening of plant startup time by allowing unrestricted combustion turbine start-up.
- Increase of efficiency during start-up by minimizing combustion turbine operation in part loads.
- Reduction of gaseous and liquid emissions through shorter start-up process and elimination of drum blow down.
- Reduced consumption of chemicals through advanced feedwater treatment.
- Improved efficiency at high ambient temperatures due to adjustable evaporating point.
- Capability for higher steam parameters (pressure and temperature), because there are no limitations through natural circulation.

[55] https://www.siemens-energy.com/global/en/offerings/power-generation/power-plants/benson-technology.html ; https://assets.siemens-energy.com/siemens/assets/api/uuid:b5c2c3b8-eb59-430b-8065-ba09d31eb37b/flyer-benson-hrsg-210920.pdf ; and https://assets.siemens-energy.com/siemens/assets/api/uuid:ef5fb27a-d2e0-4222-a0d0-2cd24146a937/new-benson-evaporator.pdf

[56] https://www.siemens-energy.com/global/en/offerings/power-generation/power-plants/benson-technology.html ; https://assets.siemens-energy.com/siemens/assets/api/uuid:b5c2c3b8-eb59-430b-8065-ba09d31eb37b/flyer-benson-hrsg-210920.pdf ; and https://assets.siemens-energy.com/siemens/assets/api/uuid:ef5fb27a-d2e0-4222-a0d0-2cd24146a937/new-benson-evaporator.pdf



The BENSON® system – Elimination of thick-walled components

FIGURE 6: FROM SIEMENS "BENSON® ONCE-THROUGH HEAT RECOVERY STEAM GENERATOR" BROCHURE, PG. 3 (2006)

The Use of Supercritical Steam Conditions

Combined cycle EGUs typically have HRSGs that operate at subcritical steam conditions. However, once-through HRSGs can be designed to operate using supercritical steam conditions. "Supercritical" is a thermodynamic term describing the state of a substance in which there is no clear distinction between the liquid and the gaseous phase (*i.e.*, they are a homogenous fluid). In contrast to a subcritical steam generator, a supercritical steam generator operates at pressures above the critical pressure—3,200 psi (22 MPa). Combustion turbine engines larger than approximately 200 MW typically have exhaust temperatures high enough to support the use of supercritical steam conditions. However, the steam turbine in combined cycle configurations where one turbine engine is paired with a steam turbine (1-1 configuration) is smaller than typical EGUs using supercritical steam conditions. Steam turbine sizes in combined cycle configurations where 2 or 3 large turbines are paired with a single steam turbine (2-1 or 3-1 configuration) are as large of typical EGUs using supercritical steam conditions.

Thermodynamic modeling has been applied to assess the potential of using supercritical steam as the working fluid in the HRSG. One study suggests that using a supercritical steam once-through HRSG will increase steam power by 5% when compared to using a subcritical steam HRSG. Since the steam turbine typically makes up approximately one-third of the overall output of a combined cycle EGU, if a combined cycle EGU designed to use supercritical steam conditions in the high-pressure portion of the steam turbine would reduce overall fuel use by 2 percent.[57] Another study analyzed the improvement of a 3PRH CC EGU when using supercritical steam as opposed to subcritical steam. It indicates that if using a supercritical steam as the working fluid for the HP turbine, it is possible to get a plant efficiency of 64.45% and capacity of 1.214 GW power output, compared to 63.08% and 1.19 GW when using subcritical steam. Additionally, the economic analysis predicts that plants can return up to an additional $14 million per year when considering the difference between the annual revenue from electricity sales and annual fuel costs when using supercritical steam.[58]

Another study compared the use of 2P and 3P cycles using subcritical and supercritical steam conditions with and without steam reheat. The results followed the patterns such that efficiency increased from 2P to 3P, from non-reheat to reheat, and from subcritical to supercritical. The analyses were conducted on *a Siemens V94.3* combined cycle gas combustion turbine, and the findings are outlined in Figure 7.[59]

FIGURE 7: RESULT OF THERMODYNAMIC ANALYSIS OF SIEMENS V94.3 COMBINED CYCLE GAS COMBUSTION TURBINE EFFICIENCIES[59]

HRSG Cycle	HP-Pressure (bar)[a]	Net LHV CC Efficiency (%)	Relative CC Efficiency Increase (%)
2PNR	80	53.6	-
2PRH	140	54.0	0.75
3PNR	100	54.1	0.93
3PRH	140	54.6	1.87
2PRH - Supercritical	250	54.6	1.87
3PRH - Supercritical	260	55.1	2.80

[a] Pressures are provided as “reasonable” choices for each HRSG cycle type

While combined cycle efficiencies routinely get above 55% on a higher heating value (HHV) basis, in current times, the result of the Bolland (1990) study still carries important implications for the comparisons of 2PNR, 3PNR, and 3PRH HRSG’s. Additionally, it useful to compare the three HRSG types with subcritical and supercritical steam as the working fluid. As shown in Figure 3 the use of supercritical steam appears to be an important option in increasing efficiency, with the efficiency of a dual pressure supercritical reheat HRSG being equal to that of a triple pressure reheat.

The Use of Alternate Working Fluid

In addition, alternate working fluids—such as the use of organic fluids, supercritical CO_2 (sCO_2), or ammonia/water mixtures rather than steam—also have the potential to increase the efficiency of

[57] Alobaid, Falah & Ströhle, Jochen & Epple, Bernd & Kim, Hyun-Gee (2009). *Dynamic simulation of a supercritical once-through heat recovery steam generator during load changes and start-up procedures.* Applied Energy, Elsevier, vol. 86(7-8), pages 1274-1282, July. https://ideas.repec.org/a/eee/appene/v86y2009i7-8p1274-1282.html.
[58] Marcin Jamróz, Marian Piwowarski, Paweł Ziemia´nski, and Gabriel Pawlak (2021). *Technical and Economic Analysis of the Supercritical Combined Gas-Steam Cycle*. Energies 2021, 14, 2985. https://www.mdpi.com/1996-1073/14/11/2985
[59] Bolland, Olav (1990). *A Comparative Evaluation of Advanced Combined Cycle Alternatives*. American Society of Mechanical Engineers (ASME). https://doi.org/10.1115/90-GT-335.

combined cycle EGUs. Organic Rankine cycles are primarily applicable to temperatures lower than combustion turbine engine exhaust temperatures.[60] While the use of sCO_2 as the working fluid in a Rankine cycle is of most interest for nuclear and coal-fired EGUs, it also has the potential to improve the overall efficiency of combined cycle EGUs.[61] The primary efficiency benefit would be for combined cycle EGUs using smaller frame or aeroderivative combustion turbine engines that typically use a double-pressure HRSG without a reheat cycle.[62] However, a HRSG using sCO_2 has the potential to improve the efficiency of combined cycle EGUs compared to triple-pressure steam with a reheat cycle as well.[63]

The potential of sCO_2 has been assessed in multiple studies. One study found sCO_2 potentially has more compact, lower-cost exhaust heat exchanger (EHX) technology when comparing system cost and performance of sCO_2 to steam-based combined cycle, the sCO_2 cycles generated higher power output at a lower cost than steam systems. Additionally, when including operation and maintenance costs (O&M), calculations demonstrated that sCO_2 can provide levelized cost of electricity (LCOE)[64] advantages as well. When comparing different steam turbine models, the LCOE decreased by an average of 15% when using sCO_2 versus subcritical steam.[65] Another study modeled the performance of sCO_2 steam use versus 2PNR and 3PRH alternative HRSG use. It found that when compared to steam for bottom cycles for 2PNR, sCO_2 as a working fluid has significantly reduced exergy flow losses at pressures above 200 bar, resulting in better performance. However, when compared to 3PRH, assuming high sCO_2 expander and pump isentropic efficiencies at 95%, the maximum pressure of the sCO_2 cycle needs to exceed 300 bar to outperform 3PRH steam cycles.[66]

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[60] The Kalina Cycle® is another cycle that has the potential for efficiency gains compared to a water-based Rankine cycle. See http://www.kalinapower.com/technology/.

[61] Patel, S. (2021b, October 27). The POWER interview: Pioneering STEP supercritical carbon dioxide demonstration ready for 2022 commissioning. *Power*. https://www.powermag.com/the-power-interview-pioneering-step-supercritical-carbon-dioxide-demonstration-readying-for-2022-commissioning/?oly_enc_id=3025B2625790F2W

[62] Using the design HRSG efficiencies listed in Gas Turbine World and the efficiency of the design efficiency of the Echogen supercritical EPS100 heat recovery system (24 percent net, https://www.echogen.com/our-solution/product-series/eps100/), the median decrease in design heat rates for replacing dual pressure HRSG with supercritical CO_2 HRSG is 7 percent.

[63] Thanganadar, D., Asfand, F., & Patchigolla, K. (2019). Thermal performance and economic analysis of supercritical carbon dioxide cycles in combined cycle power plant. *Applied Energy*, *255*(1), 113836. https://doi.org/10.1016/j.apenergy.2019.113836

[64] Levelized cost of electricity (LCOE) is defined as the price at which the generated electricity should be sold for the system to break even at the end of its lifetime. LCOE is a good indicator of cost-effectiveness, because it can be calculated without requiring for assumptions about the price at which the electricity can be sold to the grid or to an end user, as is the case when calculating the payback period or the net present value. LCOE is an indicator that can be used to compare different technologies, without any framework conditions affecting the assessment. With the use of LCOE, the financial viability in specific conditions can be indicated by just comparing directly the LCOE with the price at which electricity could be sold. Papapetrou M., Kosmadakis G. (2022). *Salinity Gradient Heat Engines*, https://www.sciencedirect.com/topics/engineering/levelized-cost-of-electricity

[65] Held, T (2015). *Supercritical CO_2 for Gas Turbine Combined Cycle Power Plants*. Echogen Power Systems. Power Gen International, December 8-10, Las Vegas, Nevada. https://www.echogen.com/_CE/pagecontent/Documents/Papers/Supercritical%20CO2%20Cycles%20for%20Gas%20Turbine%20Combined%20Cycle%20Power%20Plants.pdf.

[66] Huck, Pierre, Freund, Sebastian, Lehar, Matthew, & Peter, Maxwell (2016, March 28-31). *Performance comparison of supercritical CO2 versus steam bottoming cycles for gas turbine combined cycle applications*. GE Global Research. The 5th International Symposium - Supercritical CO2 Power Cycles, http://sco2symposium.com/papers2016/SystemConcepts/092paper.pdf

DOE's National Energy Technology Laboratory (NETL) is working on improvements to a sCO_2 power cycle.[67] One pilot power plant was recently completed which uses sCO_2 technology.[68] In 2018, Southwest Research started building a Supercritical Transformational Electric Power (STEP) pilot plant, which will use sCO_2 technology with a design capacity of 10 MWe. It is estimated that replacing water with sCO_2 increases the efficiency by up to 10%. Additionally, STEP turbomachinery can be 1/10th the size of a conventional power plant components, providing potential to lower environmental footprint and construction costs of new facilities.[69] NETL conducted a study on the use of sCO_2 in coal-fired power plants that indicate a sCO_2 power cycle can achieve higher efficiencies than a pulverized coal (PC)/Rankine systems using supercritical steam conditions with no increase of cost of electricity.[70]

Another report, released by *Echogen*, compared the use of sCO_2 as the Rankine Cycle working fluid to that of a steam-based Rankine Cycle system. *Echogen* claims their EPS100 has up to 40% lower install cost per kilowatt than that of a comparable dual pressure steam system utilizing GT-PRO/PEACE. The install cost largely results from the smaller installation footprint and simplicity of the sCO_2 system. The lower install costs contribute to a 10 to 20% lower levelized cost of electricity of the EPS100 system compared to that of traditional dual pressure heat recovery steam generators.[71] In Canada, Siemens Energy and TC Energy agreed to build a waste-heat-to-power facility using the EPS100 technology. Commissioned in 2022, the facility captures waste heat from a combustion turbine and converts it into power using a sCO_2 power cycle.[72]

Ammonia/water mixtures can be utilized as a working fluid through the Kalina Cycle. Depending on the application, the Kalina Cycle can improve power plant efficiency by 10 to 50 percent over the Rankine Cycle.[73] As plant operating temperatures are lowered, the Kalina Cycle experiences a higher increase in relative gain in comparison to the Rankine Cycle. Advantages for the Kalina Cycle include lower upfront capital costs, lower demand for cooling water and cooling infrastructure, minimal maintenance downtime, and minimal required supervision. A study found that the use of ammonia water instead of a steam only cycle increased the efficiency of the system from 57.5 percent to 62.5 percent, while the cost of electricity marginally increased from $0.06718/kWh to $0.06723/kWh.[74] A study on a system with intercooling, a triple-pressure reheat HRSG, and ammonia/water cycle at each pressure level produced a minimum cost of electricity production of 0.06723 $/kWh. The same system obtained a 62.5 percent

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[67] https://netl.doe.gov/project-information?p=FE0028979
[68] https://www.swri.org/press-release/step-10-megawatt-supercritical-carbon-dioxide-pilot-plant-building
[69] Southwest Research Institute (SRI) (2022). *Supercritical Transformational Electric Power Pilot Plant.* https://www.swri.org/industry/advanced-power-systems/supercritical-transformational-electric-power-pilot-plant.
[70] NETL (2019). *Supercritical Carbon Dioxide (Sco2) Cycle As An Efficiency Improvement Opportunity For Air-Fired Coal Combustion.* Accessed at https://www.osti.gov/servlets/purl/1511695.
[71] Persichilli, M., Kacludis, A., Zdankiewicz, E., Held, T. (April 2012). *Supercritical CO_2 Power Cycle Developments and Commercialization: Why sCO_2 can Displace Steam.* Echogen Power Systems LLC. Accessed at https://www.echogen.com/_CE/pagecontent/Documents/Papers/why-sco2-can-displace-steam.pdf.
[72] Power Magazine (2021). *First Commercial Deployment of Supercritical CO2 Power Cycle Taking Shape in Alberta*. Accessed at https://www.powermag.com/first-commercial-deployment-of-supercritical-co2-power-cycle-taking-shape-in-alberta/.
[73] Kaline Power (2015). *Technology: Kalina Cycle*. Accessed at http://www.kalinapower.com/technology/.
[74] Maheshwari, M., Singh, O. (2020). *Thermo-economic analysis of combined cycle configurations with intercooling and reheating.* Accessed at https://www.sciencedirect.com/science/article/pii/S0360544220311567.

maximum value of efficiency, a second law efficiency of 60.7 percent, and a maximum work output of 1789.39 kJ/kg of air.

The Use of Thermoelectric Materials

Combined cycle EGUs generate significant quantities of relatively low-temperature heat (i.e., waste or byproduct heat) that cannot be used by the traditional Rankine cycle and is sent to the power plant cooling system (i.e., cooling tower). If this energy could be recovered to produce additional electricity, it could reduce the environmental impact of power generation. Thermoelectric materials (e.g., bismuth telluride (Bi2Te3), lead telluride (PbTe), silicon-germanium (SiGe, magnesium antimonide (Mg3Sb2), and magnesium bismuthide (Mg3Bi2)) can be used to generate electricity due to temperature differences across the material.[75,76] While still in development, this technology has the potential to recover useful energy from the waste heat from power plants. However, if a thermoelectric generator were able to convert 5 percent of combustion turbine waste heat to electric output, the CO_2 emissions rate for simple cycle EGUs would be reduced by approximately 10 percent and combined cycle EGUs by approximately 5 percent.

Currently, optimizing thermo electric generation (TEG) power output and efficiency very dependent on thermoelectric (TE) material properties and dimensions. Currently, TE materials are based on use of tellurium and germanium, which are expensive elements. Consequently, development of polymer, silicide, oxide and tetrahedrite TE materials are being explored. Challenges of commercial TEG are mainly the materials development and systems engineering.[77]

However, the potential of TEG utility has been studied and shown promising results. On a study of a ship's waste heat recovery, it was concluded that a TEG-organic Rankine cycle (ORC) method increase waste heat utilization rate while reducing power generation cost. Results show that for a TEG/ORC bottom cycle ratio of 0.615, the output power, thermal efficiency, and generation cost of the TEG-ORC combined cycle experimental system were estimated to be 134.50 W, 6.93%, and 0.461 $/kWh, respectively.[78] Another study showed the promise of bismuth-telluride-based thermoelectric micro-generators (μ-TEGs) when it found that a power output of 5.5 μW per thermocouple can be generated under a temperature difference of only 5 K.[79] The findings of these studies are indicative of TEGs potential to increase energy efficiency of combustion turbines.

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[75] Electricity can also be generated from electrochemical reactions at different temperatures and pressures, See https://jtecenergy.com/technology/. In addition, thermogalvanic cells use temperature differences to generate an electric current. (See e.g., Yuan)

[76] Yuan Yang, *et al. (2014). Charging-free electrochemical system for harvesting low grade thermal energy.* https://www.pnas.org/content/111/48/17011

[77] LeBlanc, S. (2014). *Thermoelectric generators: Linking material properties and systems engineering for waste heat recover applications*. Sustainable Materials and Technologies. Volumes 1-2, Pages 25-35. https://doi.org/10.1016/j.susmat.2014.11.002.

[78] Kiu, C., Ye, W., Li, H., Liu, J., Zhao, C., Mao, Z., & Pan, X. (2020). *Experimental study on cascade utilization of ship's waste heat based on TEG-ORC combined cycle.* International Journal of Energy Research. https://doi.org/10.1002/er.6083.

[79] Oualid, S. E., Kosior, F., Dauscher, A., Candolfi, C., Span, G., Mehmedovic, E., Paris, J., & Lenoir, B. (2020). *Innovative design of bismuth-telluride-based thermoelectric micro-generators with high output power.* Energy & Environmental Science. Issue 10. https://pubs.rsc.org/en/content/articlelanding/2020/EE/D0EE02579H .

Combined Cycle Start-up Times

Improving start-up time of combined cycle EGUs make combined cycle EGUs a more dependable power source for load following supply, and research/practice suggests several ways to improve combined cycle start-up times. Combustion turbines operating as EGUs in a combined cycle system have historically been designed to operate for extended periods of time at steady loads. Since these combined cycle EGUs were not intended to start and stop on a regular basis, they had relatively long startup times depending on unit-specific factors and whether startup was initiated from a cold, warm, or hot state. During the past decade, the demands placed on this conventional mode of steady, base-load operation have changed. The latest combined cycle EGUs are designed with advanced technology and features to be more flexible and respond faster to increased demand for reliable electricity, support increased generation from intermittent sources (*i.e.*, renewables), capitalize on financial incentives to improve dispatch or supply non-spinning reserves, operate at higher efficiencies, and emit less pollution. As a result, advanced fast-start, combined cycle EGUs incorporate multiple techniques that allow the EGU to start and stop faster, cycle output faster, and maintain higher part-load efficiencies than previous designs.

Several combustion turbine manufacturers market complete combined cycle systems that can ramp up to full load from a cold start in less than an hour, depending on unit-specific factors. Advanced combustion turbines, when isolated from the HRSG and steam turbine, can reach full load at full speed as a simple cycle (*i.e.*, Brayton) unit in less than 20 minutes.[80] When adhering to some of the following fast-start techniques, the HRSG, steam turbine, and balance of plant equipment can reach safe operating temperatures and pressures and begin generating additional electricity within 30-45 minutes of ignition of the combustion turbine. Techniques that can be used to reduce start-up times for combined cycle systems are discussed below.

Slower start up time of combined cycle EGUs is largely attributed HRSG's needing a slower and more gradual start-up to reduce thermal stress in the HRSG thick-walled components, such as steam drums. During start-up, a temperature gradient will exist between the inside and outside of a steam drum, leading damage of the steam drum if not properly managed.[81] However, because the slow start-up of the full combined cycle is limited by the HRSG, the combustion turbine can start-up and begin producing power if the combustion turbine exhaust gas is properly managed.

One option is to employ a bypass damper to reduce the amount of exhaust gas passing through the HRSG as it warms up. The damper blocks the natural draft of cooler, ambient air back through the HRSG stack. Another practice to maintain temperature is to insulate the HRSG stack.[82] Keeping critical elements of the HRSG in a warm or hot state following shutdown is an important technique for reducing

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[80] Gálen, S.C. (2013). *Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept*. Accessed at http://www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Physics.pdf.
[81] Power Magazine (2013). *Fast-Start HRSG Life-Cycle Optimization*. June 1, 2013. Accessed at https://www.powermag.com/fast-start-hrsg-life-cycle optimization/#:~:text=The%20temperature%20gradient%20that%20exists,pressure)%20to%20cause%20fatigue%20damage.
[82] Eddington, et al. (2017). *Fast start combined cycles: how fast is fast?.* Accessed at https://www.power-eng.com/emissions/fast-start-combined-cycles-how-fast-is-fast/#gref.

startup times. Reducing the exhaust gas passing through the HRSG allows for the steam turbine to ramp up to full power without jeopardizing the thick-walled components within the HRSG.[83]

Additionally, bypass stack allows the exhaust energy from the combustion turbine to be decoupled from the heat recovery unit and steam turbine generator. The bypass allows the combustion turbine engine—the fastest-starting component of a combined cycle system—to operate independent of the HRSG and come to partial or full load as a simple cycle EGU at a faster ramp rate. Documented start times range from approximately 10 minutes[84] for a hot start to approximately 15-20 minutes for a warm start and to approximately 20-25 minutes for a cold start.[85] The HRSG, steam turbine generator, and balance of plant piping and equipment can then be slowly brought to temperature while the combustion turbine engine operates at high load.[86] The use of preheaters to gradually warm major steam lines can add significant time to startup procedures.[87] Figure 4 compares the load path and hot start time of a conventional combined cycle combustion turbine to that of an advanced class fast-start unit.

During a conventional startup, combined cycle turbines hold at low load for an extended time to gradually warm the HRSG and steam turbine generator components and prevent thermal stresses that can reduce the lifespan of the equipment. The elimination of this long hold is key to a fast start and may be possible with a bypass stack and a modulated damper that can control the amount of exhaust heat and flow that control the steam production rate and temperatures that reach the HRSG.[88] Fast-start, advanced class combined cycle designs may include a HRSG capable of tolerating rapid changes in temperature and flow of high-temperature exhaust generated by rapidly ramping the turbine.

Additionally, the start-up time of an HRSG is largely dependent on how warm the system is already (*i.e.*, warm start vs. cold start). Maintaining warm conditions for the HRSG after shut-down can result in faster start-up times when ramping back up. One option to do this is with cascaded latent heat storage (CLHS), which can deploy stored thermal energy to keep HRSG warm.[89] Note that start-up times to reach full load can be significantly faster for hot start-ups compared to cold start-ups. One estimate indicates that the duration of start-up for cold, warm, and hot combined cycle plants average around

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[83] Kim, T. S., Lee, D. K., Ro, S. T. (2000). *Analysis of thermal stress evolution in the steam drum during start-up of a heat recovery steam generator*. Applied Thermal Engineering. https://doi.org/10.1016/S1359-4311(99)00081-2.
[84] Pasha, A. (1992). *Combined Cycle Power Plant Start-up Effects and Constraints of the HRSG*. Proceedings of ASME Turbo Expo, 1992. Power of Land, Sea, and Air. https://doi.org/10.1115/92-GT-376.
[85] GE (2016). *Startup time reduction for Combined Cycle Power Plants*. Accessed at https://etn.global/wp-content/uploads/2018/09/Startup_time_reduction_for_Combined_Cycle_Power_Plants.pdf.
[86] Previous combined cycle designs had to operate the combustion turbine engine at low loads to slowly increase the HRSG temperature. Configurations with a stack bypass can slowly increase the percentage of the combustion turbine engine exhaust into the HRSG to increase the HRSG temperature without damage.
[87] Eddington, et al. (2017). *Fast start combined cycles: how fast is fast?*. Accessed at https://www.power-eng.com/emissions/fast-start-combined-cycles-how-fast-is-fast/#gref.
[88] Gálen, S.C. (2013). *Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept*. Accessed at http://www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Physics.pdf.
[89] Li, D., Hu, Y., Li, D., Wang, J. (2019). *Combined-cycle gas turbine power plant integration with cascaded latent heat thermal storage for fast dynamic responses.* Energy Conversion and Management. https://doi.org/10.1016/j.enconman.2018.12.082.

147.5, 117.5, and 50 minutes, respectively.[90] Thus, there is incentive to keep HRSG warm when feasible.

Purge Credit

This technique involves an EGU receiving credit for a mandatory purging of the fuel systems during shutdown and adding isolation valves in the fuel supply system. This purge of residual fuel from the combustion system with fresh, ambient air is necessary to remove excess combustible fuels in the unit and lower the risk of fire. During a conventional combined cycle startup, this purge takes place prior to ignition, which increases start times, reduces efficiency by decreasing the temperature of the HRSG, and increases thermal fatigue on the units. Generating purge credits during shutdown allows fast-start EGUs to start up without a purge.

[90] Decoussemaeker, P., Nagasayanam, A., Bauver, W. P., Rigoni, L., Cinquegrani, L., Epis, G., Donghi, M. (2016). *Startup Time Reduction for Combined Cycle Power Plants*. The Future of Gas Turbine Technology. 8th International Gas Turbine Conference. Accessed at https://etn.global/wp-content/uploads/2018/09/STARTUP-TIME-REDUCTION-FOR-COMBINED-CYCLE-POWER-PLANTS.pdf.

Appendix

Emissions Data

Introduction

This appendix describes the approach used by the EPA to identify the best performing combustion turbines with respect to efficient generation.

Approach to Identify the Best Performing Base Load and Intermediate Load Combustion Turbines

To determine the 12-operating month emissions rate (lb CO_2/MWh-gross) that is equivalent to the best system of emission reduction (BSER), the EPA analyzed the reporting CO_2 emissions per megawatt hour of gross generation reported by owners/operators of combustion turbines to the EPA's Clean Air Markets Division (CAMD). The EPA reviewed monthly emissions data between 2014 and 2021 for all simple and combined cycle combustion turbines that reported CEMS emissions data to EPA's CAMD's emissions collection and monitoring plan system (ECMPS). The procedure EPA used to determine the best performing units is as follows:

- 12-operating month average emission rates were determined using reported monthly data from January 2014 to December 2021
- The combustion turbines were sorted by lowest maximum 12-operating month emissions rate
  - o The EPA filtered out combined heat and power combustion turbines
- The best performing/most efficient combustion turbines (combustion turbines with the lowest maximum emissions rate) were sorted into two groups: simple and combined cycle combustion turbines
  - o The EPA used the maximum emissions rate and not the average or lowest achieved emissions rate because 111(b) emission standards are never to be exceeded standards and this approach takes into account variability in identifying the best performing combustion turbines
- The EPA determined the 12-operating month intermediate load emission rates by only considering average 12-operating month capacity factors of greater than 20% on a heat input basis
  - o For simple cycle turbines with no intermediate data, the EPA substituted in the highest low load 12-operaitng month average as representative of intermediate load operation—the EPA did this to avoid missing the best performing simple cycle turbines if they never operated as an intermediate load combustion turbine
- The EPA determined the 12-operating month base load emissions rate by only considering average 12-operating month capacity factors of greater than 50% on a heat input basis
  - o The EPA only considered emission rates from combustion turbines with over 12 12-operating month emission rates—this requires a minimum of 24 months of operation as a base load combustion turbine and assures variability is taken into account

Simple Cycle Turbines with the Lowest Reported Intermediate Loas Emission Rates

Based on the maximum reported intermediate load 12-operating month emission rates (with substituted low load emission rates for combustion turbines that haven't operated as intermediate load combustion turbines), 53 simple cycle turbines have maintained annual emission rates of 1,150 lb CO_2/MWh-gross, 15 have maintained annual emission rates of 1,100 lb CO_2/MWh-gross, and 2 have maintained 12-operating month emission rates of 1,000 lb CO_2/MWh-gross. Figure 1 shows the reported emission rates.

Figure 1: 12-Operating Month Intermediate Load Emission Rates for the Best Performing Simple Cycle Turbines

Facility Name	Facility ID (ORISPL)	Unit ID	Commercial Operation Date	Hourly Heat Input (MMBtu/h)	Max 12-Operating Month Intermediate Load Emissions Rate (lb CO_2/MWh-gross)	Turbine Model	Frame or Aeroderivative
NCPA Combustion Turbine Project #2	7449	NA1	04/01/96	463	983	General Electric Co-LM5000-PD (STIG)	Aeroderivative
Redding Power Plant	7307	6	11/12/10	508	998		
Panoche Energy Center	56803	1	04/09/09	975	1,049	General Electric Co-LMS100PB-DLE2	Aeroderivative
Woodland Generation Station	7266	1	12/03/93	460	1,050	General Electric Co-LM5000-PD (STIG)	Aeroderivative
Panoche Energy Center	56803	4	04/17/09	974	1,064	General Electric Co-LMS100PB-DLE2	Aeroderivative
Washington Parish Energy Center	55486	CTG02	10/01/20	2,201	1,074	General Electric 7FA	Frame
Scattergood Generating Station	404	7	09/14/15	903	1,077	General Electric Co-LMS100PA-SAC (Water)	Aeroderivative
Panoche Energy Center	56803	3	04/13/09	955	1,077	General Electric Co-LMS100PB-DLE2	Aeroderivative
Cumberland Energy Center	5083	05001	05/07/09	1,150	1,080	General Electric Co-LMS100PA-SAC (Steam)	Aeroderivative
Walnut Creek Energy Park	57515	GT1	12/31/12	892	1,080	General Electric Co-LMS100PB-DLE2	Aeroderivative
Panoche Energy Center	56803	2	04/18/09	970	1,082	General Electric Co-LMS100PB-DLE2	Aeroderivative
Washington Parish Energy Center	55486	CTG01	09/19/20	2,201	1,089	General Electric 7FA	Frame
Haynes Generating Station	400	13	02/17/13	907	1,092	General Electric Co-LMS100	Aeroderivative
Walnut Creek Energy Park	57515	GT3	02/09/13	892	1,098	General Electric Co-LMS100PB-DLE2	Aeroderivative
Walnut Creek Energy Park	57515	GT2	01/12/13	892	1,098	General Electric Co-LMS100PB-DLE2	Aeroderivative
Haynes Generating Station	400	15	05/14/13	907	1,103	General Electric Co-LMS100	Aeroderivative
Haynes Generating Station	400	11	04/14/13	907	1,104	General Electric Co-LMS100	Aeroderivative
Victoria Port Peaking Facility	61242	CT1	03/25/19	473	1,105	General Electric LM6000	Aeroderivative
Haynes Generating Station	400	14	03/05/13	907	1,114	General Electric Co-LMS100	Aeroderivative
Groton Generating Station	56238	CT002	07/01/08	787	1,114	General Electric Co-LMS100PA-SAC (Water)	Aeroderivative
Haynes Generating Station	400	16	04/18/13	907	1,115	General Electric Co-LMS100	Aeroderivative
Pueblo Airport Generating Station	56998	CT08	11/28/16	375	1,119	General Electric LM 6000 PF	Aeroderivative

Almond Power Plant	7315	1	04/08/96	459	1,119	General Electric Co-GE LM6000	Aeroderivative
Walnut Creek Energy Park	57515	GT4	02/09/13	892	1,120	General Electric Co-LMS100PB-DLE2	Aeroderivative
Haynes Generating Station	400	12	04/13/13	907	1,120	General Electric Co-LMS100	Aeroderivative
Walnut Creek Energy Park	57515	GT5	03/08/13	892	1,120	General Electric Co-LMS100PB-DLE2	Aeroderivative
Clayville	58235	U1	11/01/15	628	1,120	Rolls Royce Corp-Trent 60	Aeroderivative
Bayonne Energy Center	56964	GT7	03/25/12	603	1,124	Rolls Royce Corp Trent 60 WLE ISI	Aeroderivative
Sowega Power Project	7768	CT2	06/28/99	614	1,128	General Electric Co-GE LM6000	
Victoria City Peaking Facility	61241	CT1	12/17/19	473	1,128	General Electric Co-LM6000PC Sprint	Aeroderivative
Aurora	55279	AGS07	04/26/01	510	1,128	General Electric Co-MS6001FA	
Ocotillo Power Plant	116	GT6	02/15/19	1,000	1,130	General Electric LMS100	Aeroderivative
Bayonne Energy Center	56964	GT1	01/23/12	603	1,131	Rolls Royce Corp Trent 60 WLE ISI	Aeroderivative
Ocotillo Power Plant	116	GT5	03/13/19	1,000	1,131	General Electric LMS100	Aeroderivative
Victoria City Peaking Facility	61241	CT2	12/17/19	473	1,134	General Electric Co-LM6000PC Sprint	Aeroderivative
Bayonne Energy Center	56964	GT2	01/26/12	603	1,135	Rolls Royce Corp Trent 60 WLE ISI	Aeroderivative
Bayonne Energy Center	56964	GT8	04/11/12	603	1,135	Rolls Royce Corp Trent 60 WLE ISI	Aeroderivative
Pinckneyville Power Plant	55202	CT03	06/15/00	444	1,137	General Electric Co-Unknown	
Howard M Down	2434	U11	04/05/12	610	1,137	Rolls Royce Corp-Trent 60	Aeroderivative
Bayonne Energy Center	56964	GT5	03/13/12	603	1,139	Rolls Royce Corp Trent 60 WLE ISI	Aeroderivative
Ocotillo Power Plant	116	GT3	04/06/19	1,000	1,139	General Electric LMS100	Aeroderivative
Pio Pico Energy Center LLC	57555	CTG3	07/03/16	1,000	1,142	General Electric Co-LMS100PA-SAC (Water)	Aeroderivative
Scattergood Generating Station	404	6	08/09/15	903	1,143	General Electric Co-LMS100PA-SAC (Water)	Aeroderivative
Ocotillo Power Plant	116	GT7	01/16/19	1,000	1,144	General Electric LMS100	Aeroderivative
Shelby County	55237	SCE4	07/01/00	444	1,146	General Electric Co-LM6000PC	
Pinckneyville Power Plant	55202	CT02	06/06/00	444	1,146	General Electric Co-Unknown	
Aurora	55279	AGS05	04/21/01	510	1,146	General Electric Co-MS6001FA	

Kearny Generating Station	2404	133	05/09/12	490	1,148	General Electric Co-LM6000PC	Aeroderivative
Antelope Elk Energy Center	57865	2	04/14/16	1,941	1,148	GE 7F.05	Frame
Antelope Elk Energy Center	57865	1	05/21/15	1,941	1,149	GE 7F.05	Frame
Sand Hill Energy Center	7900	SH3	03/01/01	478	1,149	General Electric Co-LM6000PC	
Shelby County	55237	SCE5	07/01/00	444	1,149	General Electric Co-LM6000PC	
Pio Pico Energy Center LLC	57555	CTG2	07/22/16	1,000	1,150	General Electric Co-LMS100PA-SAC (Water)	Aeroderivative
Shelby County	55237	SCE7	01/01/01	444	1,152	General Electric Co-LM6000PC	
Sand Hill Energy Center	7900	SH4	03/01/01	478	1,153	General Electric Co-LM6000PC	
Malaga Power	56239	GT-2	06/01/05	480	1,154	General Electric Co-LM6000PC Sprint	Aeroderivative

Combined Cycle Turbines with the Lowest Reported Base Load Emission Rates

Based on the maximum reported base load 12-operating month emission rates, 1 combined cycle facility with 3 separate combustion turbine engines has maintained annual emission rates of 730 lb CO_2/MWh-gross, 17 individual combustion turbine engines have maintained annual emission rates of 770 lb CO_2/MWh-gross, and 62 have maintained 12-operating month emission rates of 800 lb CO_2/MWh-gross. Figure 2 shows the reported for the best performing base load combustion turbines.

Figure 2: 12-Operating Month Base Load Emission Rates for the Best Performing Combustion Turbines

Facility Name	**Facility ID (ORISPL)**	**Commercial Operation Date**	**Capacity Input (MMBtu/h)**	**Maximum 12-Operating Month Base Load Emissions Rate (lb CO_2/MWh-gross)**
Okeechobee Clean Energy Center	60345	10/10/2018	3,096	717
Okeechobee Clean Energy Center	60345	10/30/2018	3,096	719
Okeechobee Clean Energy Center	60345	9/23/2018	3,096	722
Greensville County Power Station	59913	8/11/2018	4,500	740
Port Everglades	617	7/31/2015	2,648	750
CPV Fairview, LLC	60589	9/22/2019	3,763	754
CPV Fairview, LLC	60589	9/27/2019	3,763	754
Port Everglades	617	7/21/2015	2,648	755
Port Everglades	617	11/7/2015	2,648	758
IPL - Eagle Valley Generating Station	991	11/13/2017	2,542	761
Woodbridge Energy Center	57839	10/25/2015	2,807	761
Dresden Energy Facility	55350	10/27/2011	2,250	762
Bridgeport Harbor Station	568	5/9/2019	3,706	765
Lagoon Creek	7845	6/30/2010	2,243	765
IPL - Eagle Valley Generating Station	991	11/1/2017	2,542	765
Dresden Energy Facility	55350	11/8/2011	2,250	767
Pasadena Power Plant	55047	7/1/2000	1,980	769
Riviera Beach Energy Center	619	10/8/2013	3,046	773
Woodbridge Energy Center	57839	11/4/2015	2,807	774
Greensville County Power Station	59913	7/20/2018	4,500	775
Lackawanna Energy Center	60357	9/12/2018	3,500	780
Riviera Beach Energy Center	619	9/22/2013	3,046	780
Lackawanna Energy Center	60357	7/1/2018	3,304	780
Lackawanna Energy Center	60357	3/3/2018	3,304	782
Magic Valley Generating Station	55123	7/29/2001	2,700	782
Cape Canaveral	609	11/23/2012	3,046	783
Birdsboro Power	61035	2/7/2019	3,345	784

Allen	3393	9/20/2017	3,797	784
Kendall Green Energy LLC	1595	8/8/2002	2,450	784
Oregon Clean Energy Center	59764	3/8/2017	3,237	785
Riviera Beach Energy Center	619	10/30/2013	3,046	785
Cape Canaveral	609	12/16/2012	3,046	786
Cape Canaveral	609	12/6/2012	3,046	786
Colorado Bend II	60122	3/2/2017	4,564	787
Wolf Hollow II	59812	1/5/2017	4,564	788
Greensville County Power Station	59913	7/30/2018	4,500	789
Colorado Bend II	60122	2/10/2017	4,564	790
St. Joseph Energy Center LLC	57794	12/29/2017	2,636	791
St. Joseph Energy Center LLC	57794	12/17/2017	2,636	792
Oregon Clean Energy Center	59764	5/18/2017	3,237	792
Moxie Freedom Generation Plant	59906	2/7/2018	3,700	792
Crystal River	628	10/16/2018	3,292	793
Crystal River	628	8/27/2018	3,292	793
Rio Nogales Power Project, LP	55137	4/1/2002	2,090	793
Sewaren Generating Station	2411	4/27/2018	4,182	793
Crystal River	628	8/23/2018	3,292	794
CPV Towantic Energy Center	56047	2/26/2018	2,899	794
Crystal River	628	10/7/2018	3,292	794
Wolf Hollow II	59812	1/12/2017	4,564	794
CPV Towantic Energy Center	56047	1/27/2018	2,899	794
Moxie Freedom Generation Plant	59906	3/11/2018	3,700	794
Polk	7242	2/23/2007	2,215	795
Newark Energy Center	58079	3/22/2015	2,531	795
West County Energy Center	56407	9/9/2009	2,958	795
Clean Energy Future - Lordstown, LLC	60376	7/14/2018	3,630	796
Martin	6043	12/10/2004	2,306	797
Plant H. Allen Franklin	7710	12/8/2001	2,600	797
Newark Energy Center	58079	3/9/2015	2,531	798
ExxonMobil Beaumont Refinery	50625	3/10/2005	2,531	799
Rio Nogales Power Project, LP	55137	4/1/2002	2,105	799
Polk	7242	4/24/2002	2,215	800
Martin	6043	12/15/2004	2,306	800

West County Energy Center	56407	12/3/2010	3,098	801
West County Energy Center	56407	12/18/2010	3,098	801
Hamilton Liberty Generation Plant	58420	1/6/2016	3,144	802
West County Energy Center	56407	4/19/2009	2,958	802
Polk	7242	4/2/2007	2,215	802
West County Energy Center	56407	9/2/2009	2,958	802
West County Energy Center	56407	9/24/2009	2,958	802
Caithness Long Island Energy Center	56234	4/17/2009	2,650	803
Clean Energy Future - Lordstown, LLC	60376	7/13/2018	3,630	803
Fox Energy Center	56031	4/28/2005	2,587	803
Wansley CC (55965)	55965	12/13/2001	2,350	803
Hamilton Liberty Generation Plant	58420	2/4/2016	3,144	803

The EPA also evaluated the maximum 12-operating month emission rates of simple cycle and combined cycle turbines and compared the emission standards the EPA is considering for emission standards that are representative of a BSER based on efficient generation in combination with best operating and maintenance practices. The EPA added additional best performing combustion turbines that commenced construction prior to 2015. Figures 3 and 4 show the proposed standards relative to the performance of combustion turbines that have commenced operation since 2015.

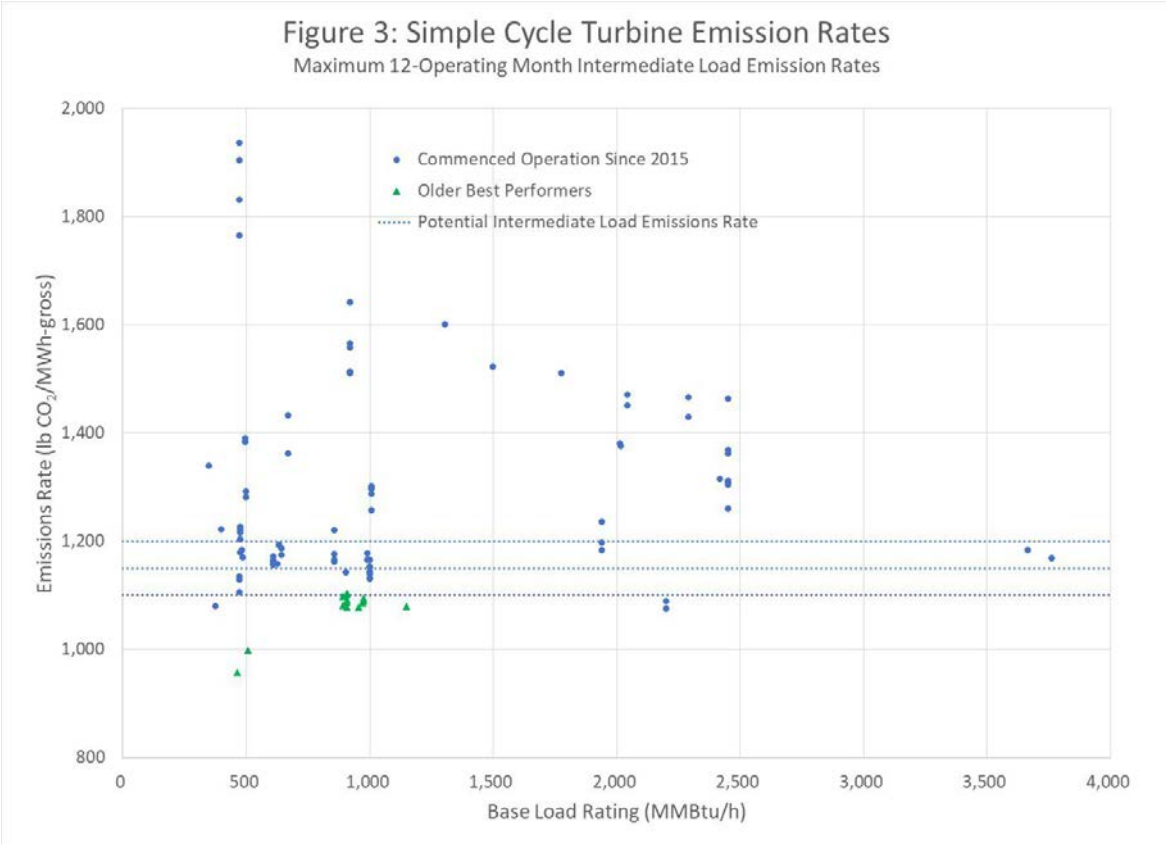
Figure 3: Simple Cycle Turbine Emission Rates
Maximum 12-Operating Month Intermediate Load Emission Rates
Commenced Operation Since 2015
Older Best Performers
Potential Intermediate Load Emissions Rate
Emissions Rate (lb CO2/MWh-gross)
Base Load Rating (MMBtu/h)
2,000
1,800
1,600
1,400
1,200
1,000
800
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000

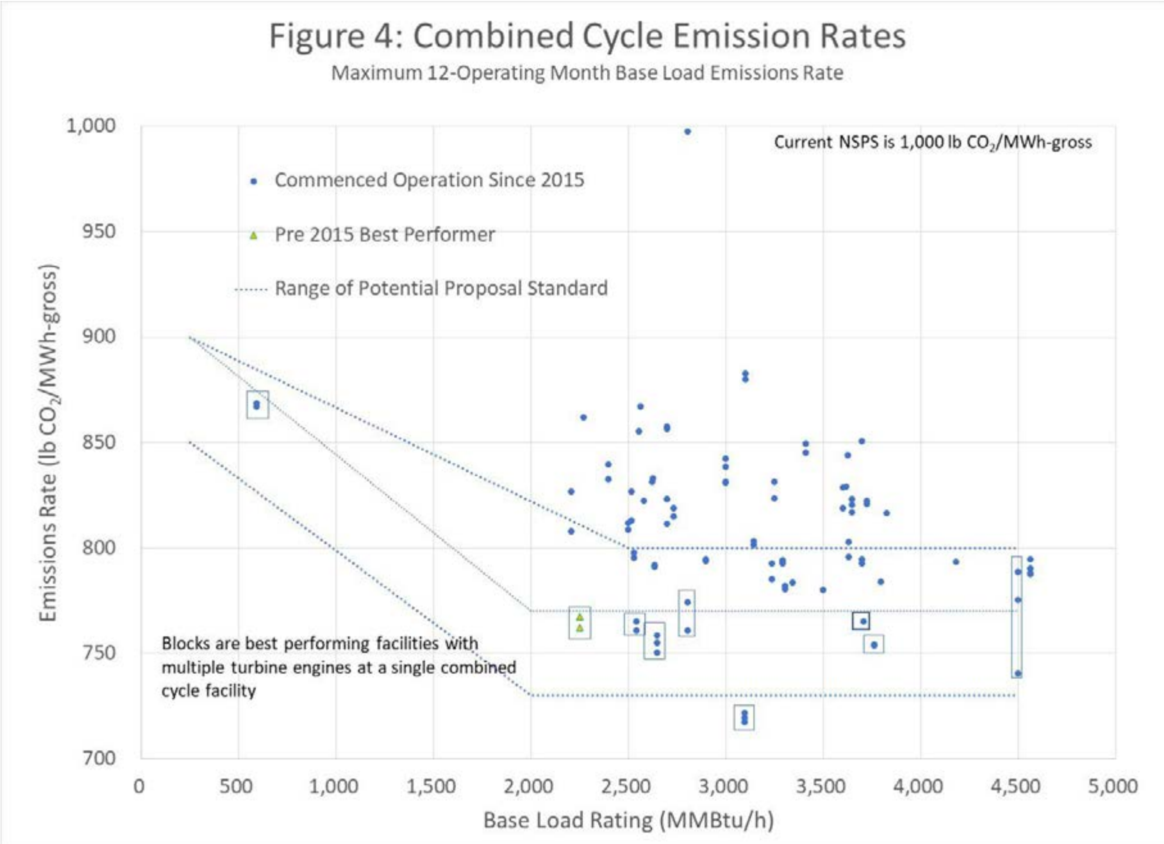
Figure 4: Combined Cycle Emission Rates
Maximum 12-Operating Month Base Load Emissions Rate
Current NSPS is 1,000 lb CO_2/MWh-gross
Commenced Operation Since 2015
Pre 2015 Best Performer
Range of Potential Proposal Standard
Blocks are best performing facilities with multiple turbine engines at a single combined cycle facility
Emissions Rate (lb CO_2/MWh-gross)
1,000
950
900
850
800
750
700
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Base Load Rating (MMBtu/h)

Natural Gas- and Oil-fired Steam Generating Unit Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

Docket ID No. EPA-HQ-OAR-2023-0072

U.S. Environmental Protection Agency
Office of Air and Radiation

March 2023

Summary

Emission rates of natural gas- and oil-fired steam generating units depend on capacity factor, and are otherwise relatively uniform between units. It is therefore reasonable to define subcategories for these types of units based on capacity factor with respective presumptive emission standards. Emission rates are stable, and relatively uniform above capacity factors of around 8 percent. For natural gas-fired units, units with annual capacity factors greater than or equal to 8 percent and less than 45 percent mostly operate with annual emission rates less than 1500 lb CO_2/MWh-gross, while units with annual capacity factors greater than or equal to 45 percent mostly operate with annual emission rates less than 1300 lb CO_2/MWh-gross. There are few, if any, continental oil-fired units with capacity factors greater than 8 percent. Those few that have reported higher capacity factors predominantly fire natural gas at nearly 90 percent or more during most operating years and can thereby achieve the same emission rates as natural gas-fired units.

Overview

Natural gas- and oil-fired steam generating units combust natural gas, oil, and other fuels in a boiler to produce steam which is converted to electricity in a steam turbine for distribution to the electric grid. The combustion of fossil fuels results in the emission of CO_2. Natural gas- and oil-fired steam generating units operate at various loads (*i.e.*, capacity factors). Steam generating units are, in general, designed to be the most efficient when operating at or near their nameplate capacity (*i.e.*, their maximum rated capacity on an electricity generation basis). When units operate at lower loads, they tend to operate less efficiently and CO_2 emission rates, relative to gross generation, can be higher. In this document, the CO_2 emission rates of natural gas- and oil-fired steam generating units are evaluated relative to capacity factor. Details of methods are provided in Appendix A.

1. Capacity Factors of Continental Natural Gas- and Oil-fired Steam Generating Units

Most natural gas-fired steam generating units operate with annual capacity factors less than 10 percent, as shown in figure 1.

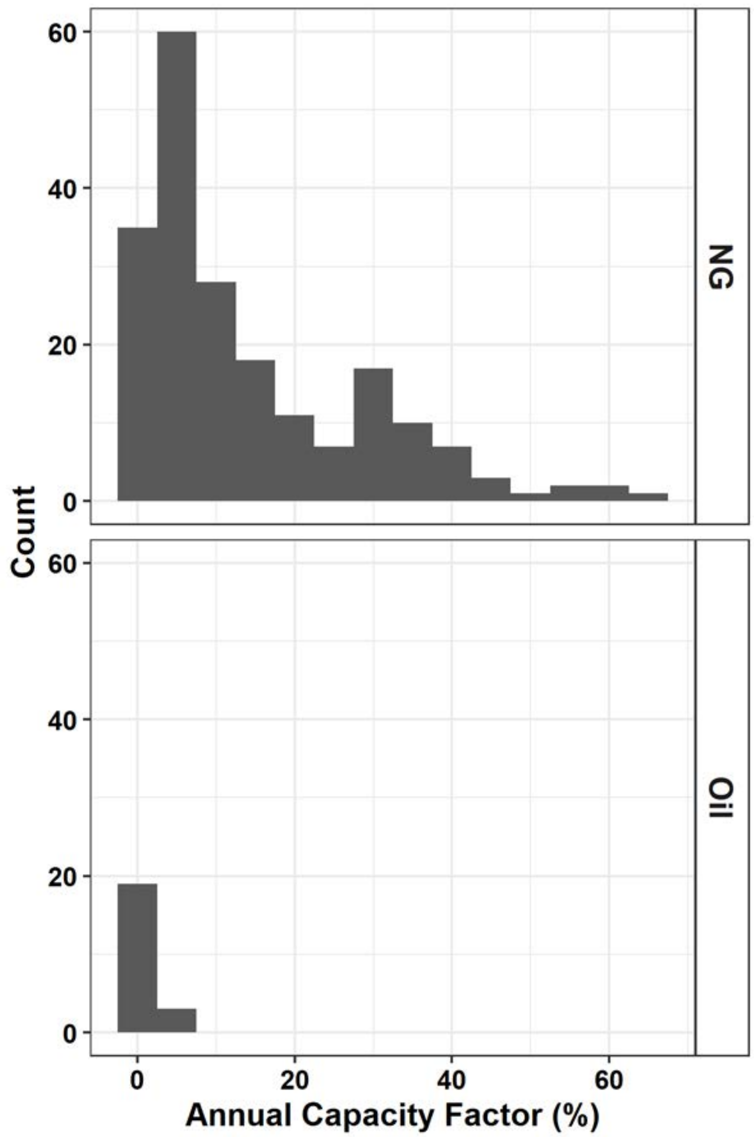

Figure 1: Annual capacity factors for 2019 based on CAMPD data.

For natural gas-fired steam generating units in 2019, 199 units with a capacity of 53 GW were identified and had an average annual capacity factor of 14.3 percent. More than 50 percent of units had annual capacity factors less than 10 percent, 75 percent of units had annual capacity factors less than 22 percent, and 90 percent of units had annual capacity factors less than 35 percent. For oil-fired steam generating units in 2019, 22 units were identified with a capacity of 11 GW and had an average annual capacity factor of 1.2 percent. About 50 percent of units had annual capacity factors less than 0.4 percent, more than 75 percent of units had capacity factors less than 1.6 percent, and more than 90 percent of units had capacity factors less than 2.7 percent.

2. CO_2 Emission Rates of Natural Gas- and Oil-fired Steam Generating Units

Annual CO_2 emission rates relative to annual capacity factor is shown in figure 2 for units with capacity factors less than 8 percent and in figure 3 for units with capacity factors greater than or equal to 8 percent. There are no, or very few, units that were identified that fired oil and operated with capacity factors greater than or equal to 8 percent. A few units were identified with higher capacity factors, however, these units predominantly fired natural gas at levels over 80 percent on average, and are discussed in detail in section 2.b.i of this document. Capacity factors above 8 percent are relatively stable. Furthermore, compared to coal-fired units which have annual emission rates can vary between units from 1700 to 2500 lb CO_2/MWh-gross even at annual capacity factors above 80 percent, the emission rates of natural gas- and oil-fired steam generating units with capacity factors above 8 percent are relatively consistent between units and typically vary from about 1200 lb CO_2/MWh-gross to around 1500 lb CO_2/MWh-gross.

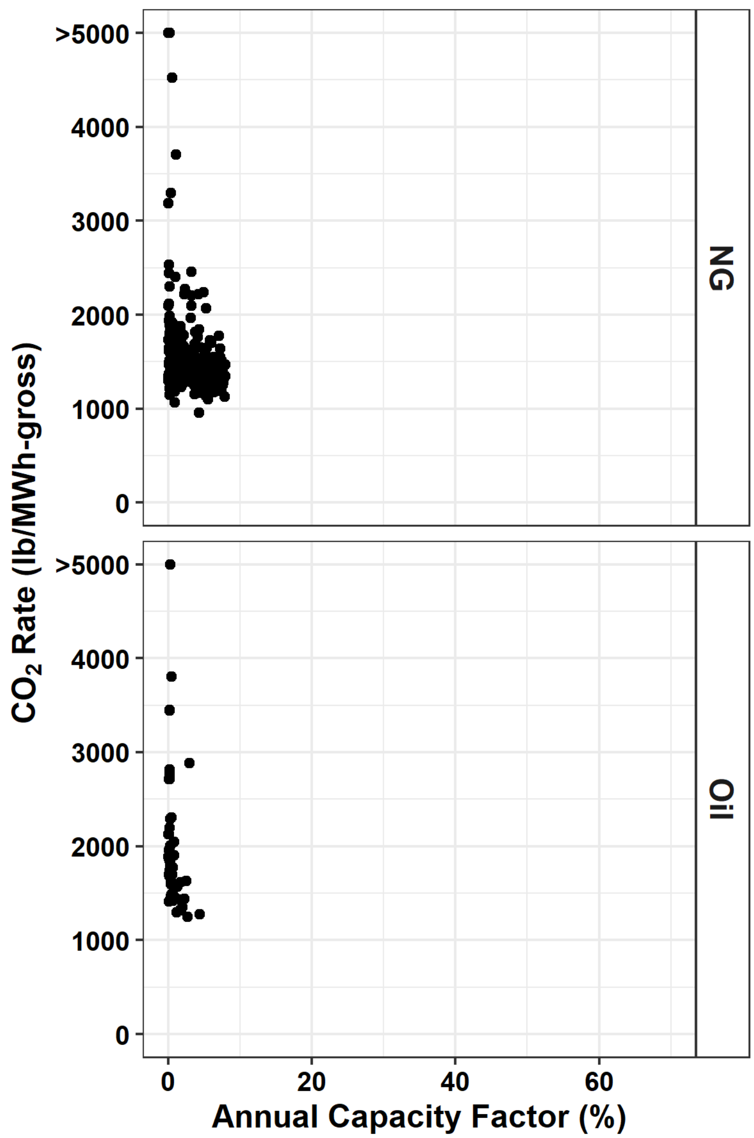

Figure 2: Annual CO_2 emission rates (lb/MWh-gross) vs annual capacity factors, data from 2015 through 2021, for units with capacity factors less than 8 percent.

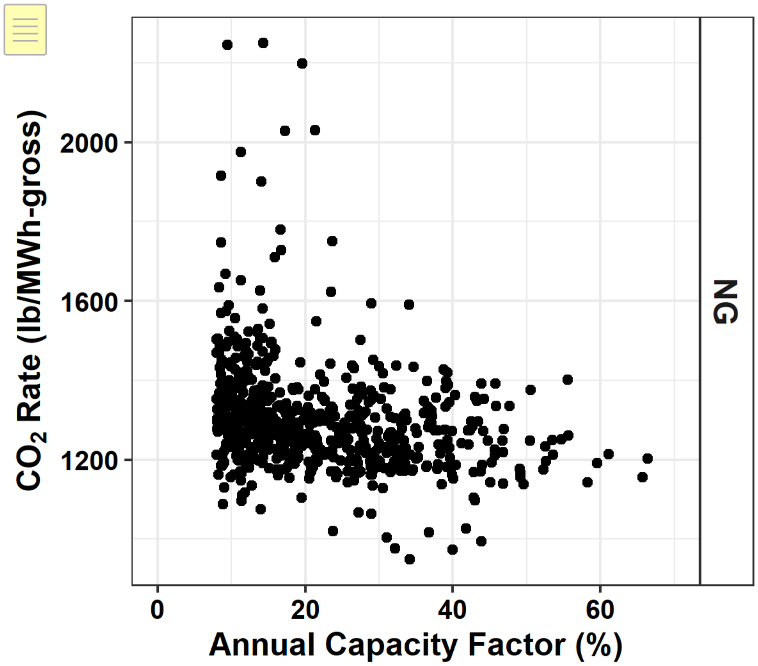

Figure 3: Annual CO_2 emission rates (lb/MWh-gross) vs annual capacity factors, data from 2015 through 2021, for natural gas-fired units with capacity factors greater than or equal to 8 percent.

a. CO_2 Emission Rates for Natural Gas-fired Steam Generating Units

Natural gas-fired units with low annual capacity factors have variable emission rates. For 159 units with capacity factors less than 8 percent, 50 percent of units have a maximum emission rate less than 1450 lb CO_2/MWh-gross and about 90 percent of units have a maximum emission rate less than about 2500 lb CO_2/MWh-gross, whereas some units have emission rates above 5000 lb CO_2/MWh-gross. It may therefore be challenging to define presumptive standards for those units.

Natural gas-fired units with intermediate capacity factors have relatively stable, lower emission rates. For 157 units with capacity factors greater than 8 percent and less than 45 percent, 50 percent of units never exceed an emission rate of 1323 lb CO_2/MWh-gross, about 75 percent of units never exceed an emission rate of 1400 lb CO_2/MWh-gross, about 90 percent of units never exceed an emission rate of 1500 lb CO_2/MWh-gross, and more than 95 percent of units never exceed an emission rate of 1600 lb CO_2/MWh-gross.

For 148 units with capacity factors greater than 10 percent and less than 50 percent, 50 percent of units never exceed an emission rate of 1310 lb CO_2/MWh-gross, 75 percent of units never exceed an emission rate of 1400 lb CO_2/MWh-gross, 90 percent of units never exceed an emission rate of 1500 lb CO_2/MWh-gross, and 95 percent of units never exceed an emission rate of 1572 lb CO_2/MWh-gross.

Natural gas-fired units with high annual capacity factors (*i.e.*, base load units) have lower emission rates. For 25 units with capacity factors greater than 40 percent, 50 percent of units never exceed an emission rate of 1250 lb CO_2/MWh-gross, 75 percent of units never exceed an emission rate of 1300 lb CO_2/MWh-gross, 90 percent of units never exceed an emission rate of 1361 lb CO_2/MWh-gross, and 95 percent of units never exceed an emission rate of 1387 lb CO_2/MWh-gross.

For 9 units with capacity factors greater than 50 percent, 50 percent of units never exceed an emission rate of 1234 lb/MWh-gross, 75 percent of units never exceed an emission rate of 1250 lb CO_2/MWh-gross, about 90 percent of units never exceed an emission rate greater than 1380 lb CO_2/MWh-gross, and 95 percent of units never exceed an emission rate of 1392 lb CO_2/MWh-gross.

To expand the data set, it can be helpful to evaluate units with similar operating profiles. About 90 percent of units with capacity factors greater than 40 percent have duty cycles great than 50 percent.

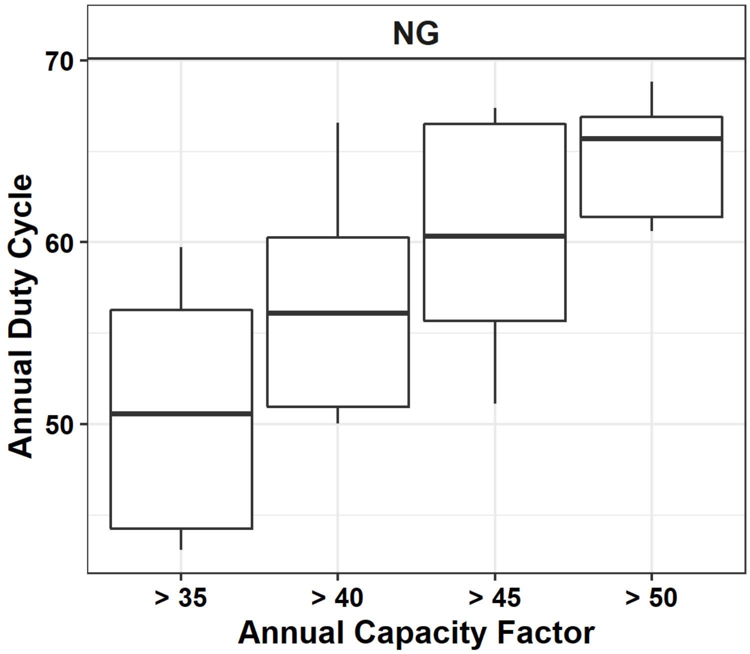

Figure 4: Boxplot of minimum annual duty cycle versus capacity factor group. Outer lines mark the 10th and 90th percentiles. Outer edges of the boxes mark the 25th and 75th percentiles. Center lines mark the 50th percentiles.

Units with higher duty cycles operate more efficiently and with lower emission rates. For the 54 units with duty cycles greater than 50 percent and capacity factors greater than 20 percent, 50 percent of units never exceed an emission rate of 1252 lb CO_2/MWh-gross, 75 percent of units never exceed an emission rate of 1330 lb CO_2/MWh-gross, 90 percent of units never exceed an emission rate of 1390 lb CO_2/MWh-gross, and 95 percent of units never exceed an emission rate of 1414 lb CO_2/MWh-gross.

Based on the analyses above, it is reasonable to define subcategories for natural gas-fired steam generating units based on capacity factor and, for the intermediate and base load subcategories, determine presumptive standards on a fleetwide basis.

b. *CO_2 Emission Rates for Oil-fired Steam Generating Units*

There are likely no or very few oil-fired steam generating units with capacity factors greater than 8 percent in the continental U.S. Emission rates for units. As evidenced by the data in figure 2, emission rates for oil-fired units with low capacity factor can vary considerably.

i. Units Near the Threshold for Oil-firing

Excluded from the calculations in section 2.a. of this document were the units at two power plants which alternated between natural gas- and oil-fired status between 2015 and 2021. In 2019, two units at those facilities were the only units from across the fleet that met the proposed definition for oil-fired steam generating units while having annual capacity factors greater than 8 percent (10.7 percent – Northport Unit 1; 10.9 percent – Port Jefferson Unit 4). Both fired significant proportions of natural gas (92.9 percent – Northport Unit 1; 97.9 percent – Port Jefferson Unit 4) in 2019 but exceeded the threshold for oil-fired classification (greater than 15 percent oil firing) in at least one of the other two years in the past three years. Between 2019 and 2021, the four natural gas- and oil-fired steam generating units at Northport had a cumulative heat input fraction from natural gas of 94.9 percent, an average capacity factor of 23.3 percent, and an average CO_2 emission rate of 1240 lb CO_2/MWh-gross. Between 2019 and 2021, the two natural gas- and oil-fired steam generating units at Port Jefferson had a cumulative heat input fraction from natural gas of 92.2 percent, an average capacity factor of 12.9 percent, 1290 lb CO_2/MWh-gross.

This suggests that while there could be units that would be classified as oil-firing at intermediate and base load, they would likely be able to achieve emission rates consistent with natural gas-firing because they fire high levels of natural gas on average.

ii. High Duty Cycle Units Firing Mostly Oil

Although units that fire 90 percent or more of their heat input on oil in the continental U.S. usually operate with low annual capacity factors, some units operate with higher annual duty cycles. Those units with higher duty cycles may be representative of the emission rates that could be achievable if units were to operate at higher capacity factors, as shown in figure 5. Based on figure 5, considering the low annual capacity factors of this data influence the observed emission rates, it may be reasonable to anticipate that an intermediate load oil-fired unit could operate with emission rates less than 2000 lb CO_2/MWh-gross and a base load unit could operate with emission rates less than 1800 lb CO_2/MWh-gross. However, based on historical data, oil-fired units operating with capacity factors greater than 8 percent appears to be an unlikely scenario.

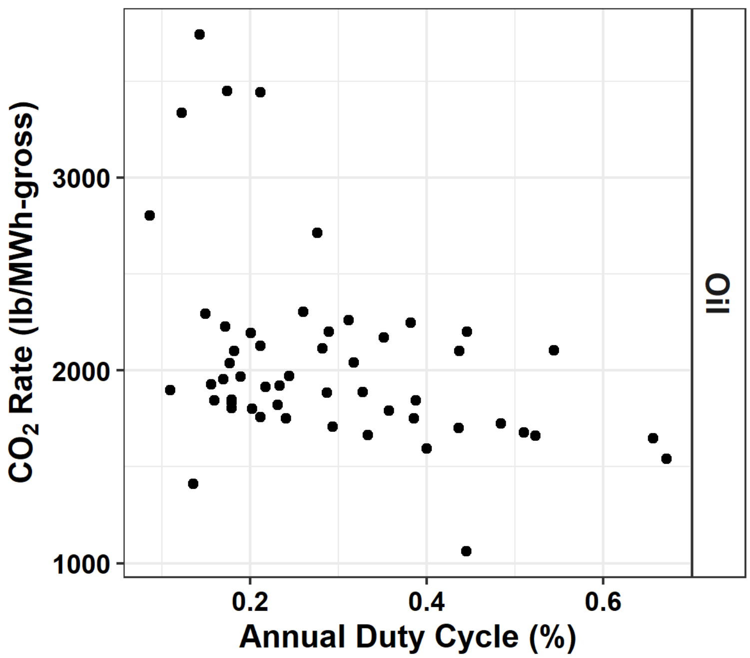

Figure 5: Emission rates vs duty cycle for oil-fired steam generating units.

Appendix A: Methods

A.1. EIA923 fuel data:

EIA form 923 reports generation data by mover (source) type for power plants connected to the electric grid. EIA form 923 data were accessed from https://www.eia.gov/electricity/data/eia923/. The third sheet (Page 3 Boiler Fuel Data) for each year were compiled in R into a single data frame. Data were filtered to exclude years prior to 2015 and data from combined heat and power plants. Fuel use data were summarized for each data year for steam generating units (reported prime mover of "ST" – steam turbine) for each unique combination of facility identifier (ORIS plant code) and boiler identifier (boiler ID).

A.2. CAMD Data

Facility level data (2015-2021) and annual emission data (2015-2021) were accessed through the CAMPD custom data download tool (https://campd.epa.gov/data/custom-data-download). Data were filtered to exclude units other than steam generating units (unit type "boiler"). Nameplate capacity was determined based on the information reported in the CAMPD facility level data and matched back to the turbine's unit ID. Additional unit level information from NEEDS () and EIA form 860 () were incorporated into the data set. Annual boiler level fuel use data from EIA form 923 (noted above) were also incorporated, as were EIA form 923 plant level disposition data (EIA923 Schedules 6-7, "Source and disposition"). Units were dropped from subsequent analyses if they were not steam generating units, if the boiler to steam turbine ration was not 1-to-1, fired only coal, fired significant amounts of non-fossil fuels, were smaller than 25 MW, were at plants with low disposition to the electric grid, or if they were associated with combined heat and power. One facility was an outlier with abnormally high annual emission rates (greater than 2000 lb CO_2/MWh-gross) at high annual capacity factors (greater than 80 percent) was excluded that fired roughly 90 percent natural gas and 10 percent biomass solids, and was excluded from further analysis.

A.2.1. Annual CAMD Data

After filtering the units on the preceding criteria, annual (calendar year) capacity factors for each unit were determined by dividing the total gross generation (MWh) by the product of the unit's nameplate capacity (MW) and the total number of hours in that calendar year (8760 hours for most years and 8784 hours for leap years). Annual duty cycles were similarly calculated relative to the sum of operating hours in a year. Annual emission rates were calculated by dividing the sum of CO_2 emissions over the annual generation.

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Stationary Combustion Turbine Electric Generating Units

APPLICABILITY

§60.5508a What is the purpose of this subpart?

This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER**],

§60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any stationary combustion turbine that commenced construction or reconstruction after [**INSERT DATE OF PUBLICATION IN FEDERAL REGISTER].**

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (9) of this section.

(1) [RESERVED]

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each stationary combustion turbine) is 25 MW or less.

(5) [RESERVED]

(6) [RESERVED]

(7) [RESERVED]

(8) [RESERVED]

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

EMISSION STANDARDS

§60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in Table 1 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in Table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, low-GHG hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under §60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section. Any combustion turbine burning hydrogen fuel for compliance purposes must co-fire 30 percent by volume low-GHG hydrogen.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with §60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using

one of the methods under §60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2\ emissions\ standard\ = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating or less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 350 kg CO_2/MWh-gross (770 lb CO_2/MWh-gross) or 360 kg CO_2/MWh-net (790 lb CO_2/MWh-net); 40 kg CO_2/MWh-gross (90 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); or 310 kg CO_2/MWh-gross (680 lb CO_2/MWh-gross) or 320 kg CO_2/MWh-net (700 lb CO_2/MWh-net) as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h) (410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net))

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

$$CO_2\ emissions\ standard\ = \text{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in §72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) [RESERVED]

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580a) after the calendar month in which emissions reporting is required to begin under §60.5555a(c)(3)(iii).

MONITORING AND COMPLIANCE DETERMINATION PROCEDURES

§60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under §60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under §60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in §75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see §60.5555a(c)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs ~~(b)~~(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

~~(1)~~ [RESERVED]

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in §60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in §60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in §60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in §72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under §60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under §98.33(a)(3) of this chapter.

(d) Consistent with §60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see §60.17). For a combined heat and power (CHP) EGU, as defined in §60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.*, lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under §60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under §60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under §98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of part 98 of this chapter. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to part 75 of this chapter.

(e) Consistent with §60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in Table 1 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected

EGUs and you must express the operating time as “stack operating hours” (as defined in §72.2 of this chapter). If you attain compliance with the applicable emissions standard in §60.5520a at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternate, or if the EGUs are subject to different emission standards in Table 1 of this subpart, you must either (1) monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or (2) apportion the CO_2 mass emissions based on the unit’s load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in §72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with §60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in §60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under §60.5535a(b) or (c), as applicable, and either the generating load data from §60.5535a(d)(1) for output-based calculations or the heat input data from §60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only “valid operating hours” in the compliance period, *i.e.*, operating hours for which:

(i) “Valid data” (as defined in §60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

~~(ii)~~ An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input;

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable; or

(iv) Grace periods for delaying RATAs for any of the parameters used to determine the hourly carbon dioxide mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from §60.5535a for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with §60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with §60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in §60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg ((lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based

standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with §60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under §60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to at least three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with §60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 of this part, or the emissions standard calculated in accordance with §60.5525a(a)(2).

NOTIFICATION, REPORTS, AND RECORDS

§60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 of this subpart).

(b) You must prepare and submit notifications specified in §75.61 of this chapter, as applicable, to your affected EGUs.

§60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by §60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic

quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in §60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.*, the total number of valid operating hours (as defined in §60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with §60.5520a, the CO_2 emissions standard (as identified in Table of this part) with which your affected EGU must comply; and

(vi) Consistent with §60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with §60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a) of this chapter, *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under §75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under §75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with §75.4(j) of this chapter, §75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in §60.5540(a)(1)), and shall not be used in the compliance determinations under §60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under §72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under §72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under §72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in §60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under §75.53(g) and (h) of this chapter;

(ii) Operating parameter records under §75.57(b)(1) through (4) of this chapter;

(iii) The records under §75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under §75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under §75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under §75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under §75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under §75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with §60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

§60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

OTHER REQUIREMENTS AND INFORMATION

§60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under §60.8(b).

§60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.*, solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.*, solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388-99 (Reapproved 2004)$^{\varepsilon 1}$ (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as "cogeneration") means a stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17), ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see §60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396-98 (incorporated by reference, see §60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975-08a (incorporated by reference, see §60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see §60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see §60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see §60.17).

Electric Generating units or EGU means any stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps, that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low-GHG Hydrogen means hydrogen (or a hydrogen derived fuel such as ammonia) produced through a process that results in a well-to-gate GHG emission rate of less than 0.45 kilograms of CO2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H_2), determining using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model).

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.*, auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.*, the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

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Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.*, CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MWh (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.*, economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1of this subpart.

Table 1 of Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After [INSERT DATE OF PUBLICATION] (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	**CO_2 Emission standard**
Newly constructed or reconstructed stationary combustion turbine that: • Supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis • Does not co-fire 10 percent or more hydrogen by volume	For 12-operating month averages beginning before January 2035, 350 to 540 kg CO_2/MWh (770 to 1,200 lb CO_2/MWh) of gross energy output; or 360 to 550 kg CO_2/MWh (790 to 1,220 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525. For 12-operating month averages beginning after December 2034, 40 to 60 kg CO_2/MWh

	(90 to 130 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525.
Newly constructed or reconstructed stationary combustion turbine that: • Supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis • Co-fire 10 percent or more hydrogen by volume	For 12-operating month averages beginning before January 2035, 350 to 540 kg CO_2/MWh (770 to 1,200 lb CO_2/MWh) of gross energy output; or 360 to 550 kg CO_2/MWh (790 to 1,220 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525. For 12-operating month averages beginning after December 2034, 310 to 480 kg CO_2/MWh (680 to 1,100 lb CO_2/MWh) of gross energy output; or 320 to 480 kg CO_2/MWh (700 to 1,070 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525
Newly constructed or reconstructed stationary combustion turbine that supplies greater than 20% of its potential electric output and its design efficiency times its potential electric output or less as net-electric sales on both a 12-operating month and a 3-year rolling average basis	For 12-operating month averages beginning before January 2035, 520 to 700 kg CO_2/MWh (1,150 to 1,530 lb CO_2/MWh) of gross energy output; or 530 to 690 kg CO_2/MWh (1,160 to 1,550 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525. For 12-operating month averages beginning before January 2035, 450 to 590 kg CO_2/MWh (1,000 to 1,290 lb CO_2/MWh) of gross energy output; or 460 to 600 kg CO_2/MWh (1,010 to 1,300 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525.
Newly constructed or reconstructed stationary combustion turbine that supplies 20% or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in §60.5525.

Table 2 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	**Subject of citation**	**Applies to subpart TTTTa**	**Explanation**

§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580a.
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	No	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§60.8(c) – (f)	Conducting performance tests	No	
§60.9	Availability of Information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13 (a) – (h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.

§60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.

TVA TENNESSEE VALLEY AUTHORITY

1101 Market Street, Chattanooga, Tennessee 37402

March 29, 2023

Electronic Submittal

(https://www.regulations.gov)

Attention: Docket ID No. EPA-HQ-OAR-2023-0072

TENNESSEE VALLEY AUTHORITY (TVA) COMMENTS ON U.S. ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED RULE, NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL-FIRED ELECTRIC GENERATING UNITS; EMISSIONS GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; AND REPEAL OF AFFORDABLE CLEAN ENERGY RULE.

Dear Sir or Madam:

TVA appreciates the opportunity to engage in pre-proposal outreach.

TVA is a non-profit corporate agency of the United States that provides electricity for business customers and local power distributors serving nearly 10 million people in parts of seven southeastern states. TVA receives no taxpayer funding, deriving virtually all its revenues from sales of electricity. As part of its regional resource development mission, TVA operates the nation's largest public power system. The energy resources that TVA relies upon to serve the public are diverse and include nuclear plants, natural gas plants, hydroelectric dams, coal-fired power plants, renewable energy, and energy efficiency. TVA has retired or announced the retirement of nearly 60% of its coal fired units, and moving forward, is evaluating the impact of retiring the balance of the coal fleet by 2035, consistent with TVA's strategic planning and decarbonization efforts. TVA recognizes the importance of implementing GHG reductions, using technologies which are technically feasible, economically achievable, adequately demonstrated and implemented on a timeframe that preserves electric reliability and affordability. If you have questions, please contact me at wcmarkham@tva.gov.

Sincerely,

Wilbourne C. Markham Jr

Wilbourne C. Markham
Senior Manager
EMS and Regulatory Affairs

Enclosure

Resource Adequacy and Reliability Analysis
Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

Docket ID No. EPA-HQ-OAR-2023-0072

U.S. Environmental Protection Agency
Office of Air and Radiation
March 2023

This document supports the EPA's proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Standards and describes projected resource adequacy and reliability impacts of the proposed rules. As used here, the term resource adequacy is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region,[1] while reliability includes the ability to deliver the resources to the loads, such that the overall power grid remains stable. This document is meant to serve as a resource adequacy assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the IRA.

The proposed rules establish emissions rate limits for covered electric generating units (EGUs). The stringency of these emission rate limits is set through assuming the installation of various greenhouse gas (GHG) emissions control technologies. Covered sources would therefore be able to comply with the rules with these technologies and are not required to reduce utilization or shift generation. Nonetheless, in light of the transition of the power sector toward less emitting generating resources, as highlighted by stakeholders, it is anticipated that EGU owners and operators may pursue alternative compliance strategies. Should those strategies involve the curtailment or retirement of existing generating resources, stakeholders have separately raised concerns that this could impact the reliability of the power grid.

While such potential impacts would not be a direct result of these rules but rather of the compliance choices source owners and operators may pursue, we have analyzed whether the projected effects of the rules would in this regard pose a risk to resource adequacy, a key planning metric that informs grid reliability. It is important to recognize that the proposed rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric reliability. For more detail on how the proposed rules address reliability concerns, see Section XV.F of the preamble. The results presented in this document show that the projected impacts of the proposed rules on power system operations, under conditions preserving resource adequacy, are modest and manageable.

The results presented in this document further demonstrate, for the specific cases illustrated in the Regulatory Impact Analysis (RIA), that the implementation of these rules can be achieved without undermining resource adequacy. The focus of the analysis is on comparing the illustrative proposed rules scenario from the RIA to a base case (absent the proposed requirements) that is assumed to be adequate and reliable. In this framework, the emphasis is on the incremental changes in the power system that are projected to occur under the presence of the

[1] As analyzed in this document, power regions correspond to aggregates of IPM regions corresponding to NERC assessment areas.

rules in the 2030, 2035 and 2040 model run years[2]. The EPA uses the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed rules.[3]

IPM's least-cost dispatch solution, in concert with the model's capacity expansion decision-making framework, is designed to ensure generation resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system. Within each model region, IPM assumes that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region. This document focusses on key regional results important to management of the power system. For a more complete presentation of the projected power sector impacts of the proposed rules, see the Regulatory Impact Analysis.

Overview

These rules establish CO_2 emission rate limits on covered fossil fuel-fired power plants (EGUs) in the US. The EGUs covered by the rules and subject to these limits are existing fossil-fuel fired steam generating units with >25-megawatt (MW) capacity, and new, modified, and reconstructed stationary combustion turbine EGUs. For details on the definition of the covered sources and the derivation of these emission rates, please see sections VII and X of the preamble.

This TSD uses the same scenarios and years of analysis contained in the RIA.[4] The scenarios include a base case, and the proposed rules scenario. For purposes of this resource adequacy and reliability assessment, estimates and projections are taken from those same scenarios and years as shown in the RIA (2030, 2035, and 2040).

Summary of Changes in Operational Capacity

Total operational capacity remains similar between the base and policy scenarios. The model is constrained in the policy scenario in 2023 to disallow any incremental retirements, retrofits or builds beyond those that occur in the base case. This constraint is relaxed in future years, allowing retirements, retrofits and builds to differ between the base and policy scenarios. Operational generating capacity[5] changes from the base case in 2030, 2035 and 2040 are summarized below:

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[2] IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar years 2029-2031 to run year 2030, calendar years 2032-2037 to run year 2035 and calendar years 2038-2041 to run year 2040. For model details, please see Chapter 2 of the IPM documentation, available at:
https://www.epa.gov/airmarkets/power-sector-modeling

[3] See the Regulatory Impact Analysis for more detail on the power sector impacts of the proposed rules.

[4] See Section 3 of the RIA for additional details on the scenarios examined.

[5] Operational capacity is any existing, new or retrofitted capacity that is not retired.

Table 1. Operational Capacity Summary (2030, 2035, 2040)

Capacity (GW)	2030	2035	2040
Base Case Operational Capacity	1,338	1,632	1,908
Minus Retirements			
Coal	0	-22	-17
Oil/Gas	0	0	0
NGCC	0	0	0
NGCT	0	0	0
Nuclear	0	0	0
Plus Additions			
NGCC	3.5	1.0	1.1
NGCT	0.3	23.1	18.2
Wind	0.4	2.0	-0.2
Solar	0.7	0.4	-1.0
Storage	-0.1	-2.2	-2.1
Other	0.0	0.0	0.0
Policy Case Operational Capacity	1,342	1,633	1,906

Since the model must maintain adequate reserves in each region, projected retirements must be offset by reliance on existing baseline excess reserves, incremental builds, and the ability to shift transmission flows between regions in response to changing generation mix. In the 2030 run year, an incremental 3.8 GW of NGCC/NGCT and an incremental 1.1 GW of incremental solar and wind builds occur relative to the baseline. By 2035, an incremental 22 GW of coal retirements occur, offset primarily by increases in incremental NGCT (23 GW) and renewable (2.4 GW) additions. By 2040, incremental coal retirements relative to the baseline (17 GW) are lower than in 2035 (22 GW), reflecting a convergence towards the long-term equilibrium level of remaining coal capacity.

Reserve Requirements

IPM uses a target reserve margin in each region[6] as the basis for determining how much capacity to keep operational (or build) in order to preserve resource adequacy. IPM retires capacity if it is uneconomic and no longer needed to provide energy for load or to provide capacity to meet reserve margin during the planning horizon of the projections. Since current regional reserves may be higher than the target reserve margin for a region, IPM may retire reserve capacity if it is not economic to use it to maintain adequate reserve margins. Existing resources may also be more expensive, compared to alternatives such as building new capacity or transferring capacity from another region. As a result, some of the plants that are projected to retire will not need to be replaced. Because some existing plants eventually retire in most regions, and IPM builds no more than what it needs to maintain a target reserve margin in each region, the actual reserve margins tend to approach the target reserve margins over time. For

[6] In IPM, reserve margins are used to represent the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived from reliability standards in NERC's electric reliability reports. The IPM regional reserve margins are imposed throughout the entire time horizon.

details on projected reserve margins under the base and policy scenarios, please see Appendix A-3, B-3 and C-3.[7]

Changes in Retirements and New Capacity Additions under the Proposed Rules

The incremental retirements in the proposal case are shown above in Table 1; the 22 GW of retirements in 2035 are in addition to 104 GW of coal and 15 GW of oil/gas retirements already occurring in the base case.

By 2035, the proposed rules scenario as compared to the base case leads to higher levels of overall existing coal retirements and new capacity additions (shown regionally in Table A5, B5 and C5). Renewable additions are higher under the policy case. The largest increases in new capacity are in NGCT (23 GW), followed by solar and wind (2.5 GW). These retirements and additions in the projections are the result of the model's optimization of economic planning for energy and capacity needs; they do not represent required outcomes for any individual units, which will be able to consider multiple compliance options in response to the proposed rules. In particular, new additions in a base case scenario that do not occur in the policy scenario projections might, in reality, be retained under a policy if local reliability conditions rendered this development the most appropriate choice. These rules do not prevent generation owners from shifting retirements and additions among specific sources to ensure reliability in such circumstances.

Reserve Transfers

In cases where it is economic to transfer reserves from a neighboring region, rather than supply reserves from within a region, IPM will transfer reserves, subject to summer and winter limits that are designed to ensure that these reserves can be transferred reliably. The transfer of reserves can occur, for example, if a region retires capacity that was used in the base case to meet reserve requirements, but a neighboring region has lower cost reserves that are not needed for its own reserve requirements. To examine these transfers, the EPA analyzed the change in net transfers from each region, where the net transfer for the base and policy cases is measured by the reserves sent to neighboring regions. In these cases, a positive value signifies the reserve capacity sent to other regions is larger than the reserve capacity received from other regions (sending and receiving regions can be different), while a negative value signifies that the capacity received is larger than the capacity sent. Thus, the value measures the degree to which resources in the region were reserved for use by other regions (positive value), or where the capacity to meet load in the region was served by resources in other regions (negative value). In each case these reserve transfers represent the use of the transmission system on a firm basis for at least a season.

To look at the projected impact of the policy case on transfers, the measure used was the change in the summer reserves sent in the policy case compared to the base case. To develop a relative measure of the impact of the policy, the change in reserves was measured as a

[7] See maps of IPM regions and NERC Assessment Regions, and the table of target and projected reserve margins in Appendix D. IPM regions are based on the regions NERC uses for regional assessments. These regions are used for the Appendix tables in this document

percentage of load in the sending region. This percentage gives an indication of the significance of the policy for changes in the grid. In general, the percentage changes in the proposed rules are below 2%. For details on projected transfers under the base and policy scenarios, please see Appendix A-6, B-6 and C-6.

Appendix A: Tables by IPM Region for Proposed Rules in 2030
(Note: All Results Cumulative through Projection Year)

A1. Projected Operational Capacity in GW (2030)

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,338	1,342	4	69	59	-10
ERCOT	142	141	-1	5	3	-2
FRCC	67	67	0	2	1	0
MISO	197	200	2	19	16	-3
ISONE	50	50	0	0	0	0
NYISO	54	54	0	0	0	0
PJM	222	222	0	16	15	-1
SERC	182	181	-1	13	12	-1
SPP	102	104	2	6	3	-3
WECC - non CAISO	212	211	-1	9	8	-1
CAISO	110	112	2	0	0	0

A2. Summary of Summer Peak Loads and Reserve Capacity in GW (2030)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	827	827	955	955
ERCOT	76	76	87	87
FRCC	53	53	63	63
MISO	133	133	156	156
ISONE	27	27	32	32
NYISO	33	33	38	38
PJM	155	155	179	179
SERC	132	132	151	151
SPP	55	55	63	63
WECC - non CAISO	109	109	124	124
CAISO	55	55	63	63

A3. Summary of Target and Projected Reserve Margin % (2030)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US	15%	15%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	18%	18%	18%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	16%	16%	16%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	15%	15%	15%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	14%	14%	14%	0%	0%

A4. Policy Case Retired Capacity Incremental to Base Case in GW (2030)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.1	-0.4	0.3	0.0	0.5	0.5
ERCOT	0.0	0.4	0.0	0.0	0.0	0.4
FRCC	0.0	0.1	0.0	0.0	0.0	0.1
MISO	0.0	-1.1	0.0	0.0	0.0	-1.1
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	-0.3	0.0	0.0	0.0	-0.3
SERC	0.0	-0.3	0.0	0.0	0.0	-0.3
SPP	0.0	0.4	0.0	0.0	0.3	0.7
WECC - non CAISO	0.1	0.4	0.0	0.0	0.2	0.7
CAISO	0.0	0.0	0.3	0.0	0.0	0.3

A5. New Capacity in Policy Case Incremental to Base Case in GW (2030)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	4	0	0	1	0	0	5
ERCOT	0	0	0	0	0	0	0
FRCC	0	0	0	0	0	0	0
MISO	0	0	3	-1	0	0	2
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	0	1	0	0	0	0
SERC	2	1	-3	0	0	0	-1
SPP	0	0	1	1	0	0	2
WECC - non CAISO	1	0	-1	0	0	0	0
CAISO	0	0	0	2	0	0	2

A6. Net Reserves Sent by NERC Assessment Region in GW (2030)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-4.3	-4.3	0.0	0%
ERCOT	-0.9	-1.4	-0.5	-1%
FRCC	-1.8	-1.8	0.0	0%
MISO	-6.0	-6.0	0.0	0%
ISONE	-0.6	-0.6	0.0	0%
NYISO	-1.2	-1.2	0.0	0%
PJM	-0.2	-0.2	0.0	0%
SERC	7.3	7.3	0.0	0%
SPP	1.3	1.8	0.5	1%
WECC - non CAISO	-0.5	-0.5	0.1	0%
CAISO	-1.7	-1.7	0.0	0%

Appendix B: Tables by IPM Region for Proposed Rules in 2035
(Note: All Results Cumulative through Projection Year)

B1. Projected Operational Capacity in GW (2035)

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,632	1,633	2	44	13	-31
ERCOT	172	172	0	5	2	-3
FRCC	82	82	0	1	0	-1
MISO	259	258	-1	10	3	-7
ISONE	57	57	0	0	0	0
NYISO	65	65	0	0	0	0
PJM	262	264	2	12	3	-9
SERC	222	223	1	5	1	-4
SPP	127	127	0	4	0	-4
WECC - non CAISO	252	252	-1	6	4	-2
CAISO	133	133	0	0	0	0

B2. Summary of Summer Peak Loads and Reserve Capacity in GW (2035)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	886	886	1,022	1,022
ERCOT	82	82	93	93
FRCC	57	57	68	68
MISO	140	140	164	164
ISONE	30	30	35	35
NYISO	34	34	39	39
PJM	164	164	189	189
SERC	140	140	161	161
SPP	58	58	67	67
WECC - non CAISO	120	120	137	137
CAISO	60	60	68	68

B3. Summary of Target and Projected Reserve Margin % (2035)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US	15%	15%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	18%	18%	18%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	16%	16%	16%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	15%	15%	15%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	14%	14%	14%	0%	0%

B4. Policy Case Retired Capacity Incremental to Base Case in GW (2035)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	22.2	0.2	0.0	0.3	22.7
ERCOT	0.0	1.2	0.0	0.0	0.0	1.2
FRCC	0.0	1.0	0.0	0.0	0.0	1.0
MISO	0.0	4.8	0.0	0.0	0.0	4.8
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	8.4	0.0	0.0	0.0	8.4
SERC	0.0	3.2	0.0	0.0	0.0	3.2
SPP	0.0	1.5	0.0	0.0	-0.4	1.1
WECC - non CAISO	0.1	1.9	0.2	0.0	0.7	3.0
CAISO	-0.1	0.0	0.0	0.0	0.0	-0.1

B5. New Capacity in Policy Case Incremental to Base Case in GW (2035)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	1	23	2	0	-2	0	24
ERCOT	0	1	0	0	0	0	1
FRCC	0	1	0	0	0	0	1
MISO	0	4	-1	2	0	0	4
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	7	2	0	0	0	10
SERC	0	4	0	1	0	0	5
SPP	0	0	0	0	1	0	1
WECC - non CAISO	1	1	0	0	-1	0	2
CAISO	0	4	0	-2	-3	0	-1

B6. Net Reserves Sent by NERC Assessment Region in GW (2035)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-5.4	-5.9	-0.4	0%
ERCOT	-1.6	-1.4	0.2	0%
FRCC	-2.6	-2.4	0.3	0%
MISO	-3.1	-3.8	-0.7	-1%
ISONE	-2.7	-2.4	0.4	1%
NYISO	-0.4	-0.3	0.0	0%
PJM	-2.2	-2.6	-0.5	0%
SERC	6.9	6.9	0.0	0%
SPP	2.8	2.4	-0.4	-1%
WECC - non CAISO	1.0	-0.3	-1.2	-1%
CAISO	-3.6	-2.0	1.6	3%

Appendix C: Tables by IPM Region for Proposed Rules in 2040
(Note: All Results Cumulative through Projection Year)

C1. Projected Operational Capacity in GW (2040)

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,908	1,906	-1	35	10	-26
ERCOT	191	191	0	4	2	-2
FRCC	104	104	-1	1	0	-1
MISO	295	294	-1	7	2	-5
ISONE	69	69	0	0	0	0
NYISO	75	76	0	0	0	0
PJM	322	321	-1	9	1	-7
SERC	273	275	2	5	1	-4
SPP	139	139	0	4	0	-4
WECC - non CAISO	291	290	-1	5	3	-2
CAISO	149	149	0	0	0	0

C2. Summary of Summer Peak Loads and Reserve Capacity in GW (2040)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	954	954	1,101	1,101
ERCOT	88	88	100	100
FRCC	62	62	74	74
MISO	148	148	173	173
ISONE	33	33	39	39
NYISO	36	36	41	41
PJM	176	176	203	203
SERC	150	150	172	172
SPP	62	62	72	72
WECC - non CAISO	133	133	152	152
CAISO	65	65	74	74

C3. Summary of Target and Projected Reserve Margin % (2040)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US	15%	15%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	18%	18%	18%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	16%	16%	16%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	15%	15%	15%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	14%	14%	14%	0%	0%

C4. Policy Case Retired Capacity Incremental to Base Case in GW (2040)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	17.0	0.2	0.0	0.3	17.4
ERCOT	0.0	0.7	0.0	0.0	0.0	0.7
FRCC	0.0	1.0	0.0	0.0	0.0	1.0
MISO	0.0	2.8	-0.1	0.0	0.0	2.7
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	6.5	0.0	0.0	0.0	6.5
SERC	0.0	3.0	0.0	0.0	0.0	3.0
SPP	0.0	1.6	0.0	0.0	-0.4	1.1
WECC - non CAISO	0.1	1.4	0.2	0.0	0.7	2.5
CAISO	-0.1	0.1	0.0	0.0	0.0	-0.1

C5. New Capacity in Policy Case Incremental to Base Case in GW (2040)

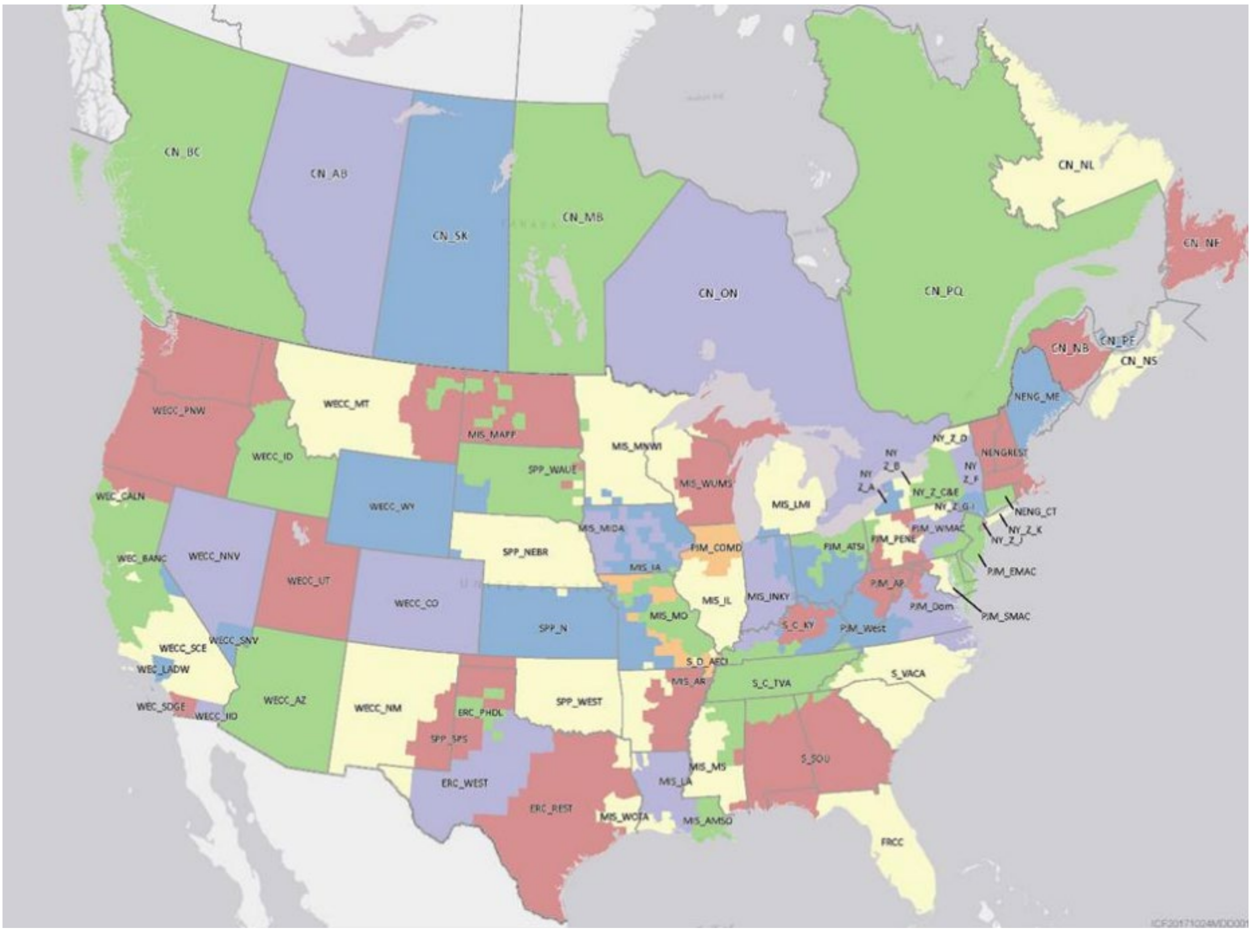
Region	CC	CT	Wind	Solar	Storage	Other	Total
US	1	18	0	-1	-2	0	16
ERCOT	0	1	0	0	0	0	1
FRCC	0	1	0	0	0	0	0
MISO	0	3	-2	0	0	0	2
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	6	0	0	0	0	6
SERC	0	3	1	2	0	0	6
SPP	0	1	0	0	0	0	1
WECC - non CAISO	1	2	1	-2	-1	0	2
CAISO	0	1	-1	-1	-1	0	-1

C6. Net Reserves Sent by NERC Assessment Region in GW (2040)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-6.9	-7.0	-0.1	0%
ERCOT	-0.9	-0.9	0.0	0%
FRCC	-2.0	-2.2	-0.2	0%
MISO	-4.1	-3.9	0.3	0%
ISONE	-2.5	-2.5	0.0	0%
NYISO	-2.0	-1.9	0.0	0%
PJM	-1.9	-2.1	-0.2	0%
SERC	7.3	7.4	0.0	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-1.2	-2.0	-0.8	-1%
CAISO	-1.6	-0.8	0.8	1%

Appendix D: Maps

IPM v6 Map



D2: NERC Assessment Areas in Long Term Reliability Assessment.

Source: NERC 2022 Long-Term Reliability Assessment

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Introduction

§ 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish emission standards limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

§ 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

> (1) For the purposes of § 51.166(b)(49)(ii), with respect to GHG emissions from facilities regulated in the plan, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.
>
> (2) For the purposes of § 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the plan, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.
>
> (3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in § 70.2 of this chapter.
>
> (4) For the purposes of § 71.2, with respect to GHG emissions from facilities regulated in the plan, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in § 71.2 of this chapter.

§ 60.5710b Am I affected by this subpart?

If you are the Governor of a State in the United States with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the United States with no affected EGUs for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715b What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27a except that under § 60.27a(b) the Administrator will have 12 months after the date the final plan or plan revision (as allowed under § 60.5785b) is submitted, to approve or disapprove such plan or revision or each portion thereof.

§ 60.5720b What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit an approvable plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved State plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a State plan.

§ 60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan submittal or a negative declaration letter (if applicable).

§ 60.5730b Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the Federal Register**.** If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your State, you will be found to have failed to submit a State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5740b What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (7) of this section in your plan submittal. The final plan must meet the requirements and include the information required under § 60.5745b.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. In addition, you must include an inventory of CO_2 emissions from the affected EGUs.

(2) *Standards of Performance.* You must include an identification of all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance (CO_2 lb/MWh-gross) that does not exceed the level calculated through the use of the methods described in § 60.5775b(c), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(i) States carry the burden of making the demonstrations required under the RULOF mechanism described in § 60.5775b(e) and have the obligation to justify any accounting for RULOF in support of less stringent standards of performance. The EPA may find that a state plan's demonstration is a basis for concluding that the plan is not "satisfactory" and may disapprove the plan on the basis that a State has not carried its burden in providing a less stringent standard based on RULOF.

(ii) States seeking to apply a more stringent standard of performance must adequately demonstrate that the standard is in fact more stringent. However, the state is not required to conduct a source-specific BSER evaluation for the purpose of applying a more stringent standard of performance, so long as the standard will achieve equivalent or better emission reductions. As for all standards of performance, the state plan must include requirements that provide for the implementation and enforcement of a more stringent standard.

(3) *Increments of Progress.* State plans must include specified enforceable increments of progress as required elements for affected EGUs within the subcategories of long-term existing coal-fired steam generating units (§ 60.5775b(b)(1)) and medium-term existing coal-fired steam generating units (§ 60.5775b(b)(2)), as follows:

(i) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan.
  (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.
  (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or FEED study.

(ii) Awarding of contracts. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded.
  (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.
  (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(iii) Initiation of on-site construction or installation of emission control equipment or process change.
  (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.
  (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, initiation of onsite construction or installation of emission

control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(iv) Completion of on-site construction or installation of emission control equipment or process change.
   (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.
   (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(v) A demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, environmental reviews, an account of meaningful public engagement to date, and a timeline to complete all pipeline permitting activities.
   (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, this increment of progress describes affected EGUs that adopt co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.
   (B) For affected units within the long-term existing coal-fired steam generating unit subcategory, this increment of progress describes affected EGUs that adopt CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.

(vi) For affected units within the long-term existing coal-fired steam generating unit subcategory only, a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities, a summary of planned environmental impacts reviews and plans for meaningful public engagement.

(vii) Final compliance with the standard of performance by January 1, 2030.

(4) *Milestones for Federally Enforceable Commitment to Cease Operations.* State plans must include legally enforceable milestones for affected EGUs within the subcategories of imminent-term existing coal-fired steam generating units (§ 60.5775b(b)(4)), near-term existing coal-fired steam generating units (§ 60.5775b(b)(3)), and medium-term coal-fired steam generating unit (§ 60.5775b(b)(2)) subcategories, as follows:

(i) Five years before the date used to determine the applicable subcategory under these emission guidelines (the date that the affected EGU permanently ceases operations) or 60 days after state plan submission, whichever is later, designated facilities must submit a Milestone Report to the applicable State administering authority that includes the following:
   (A) A summary of the process steps required for the affected EGU to cease operations by the federally enforceable date, including the approximate timing and duration of each step.
   (B) A list of key milestones, metrics that will be used to assess whether each milestone has been met, and calendar day deadlines for each milestone. These milestones must include at least the following: notice to the official reliability authority of the federally enforceable retirement date; submittal of an official suspension filing (or equivalent filing)

made to the affected EGU's reliability authority; and submittal of an official retirement filing with the unit's reliability authority.

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar units within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority, as well as any filings with the SEC or notices to investors in which the plans for the EGU are mentioned and any integrated resource plan.

(ii) For each of the remaining years prior to the federally enforceable date used to determine the applicable subcategory, affected EGUs must submit an annual Milestone Status Report that addresses the following:

(A) Progress toward meeting all milestones and related metrics identified in the Milestone Report; and

(B) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months following the date on which the affected EGU permanently ceased operations, the EGU must submit a Final Milestone Status Report that documents what the unit has done to make the closure permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) Affected EGUs with reporting milestones for enforceable commitments to cease operations would be required to post their initial Milestone Report, annual Milestone Status Reports, and final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the CAA Section 111(d) EGU Rule Website required by subsection (7) of this section within 30 business days of being filed.

(5) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(6) *State reporting.* You must include in your plan a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress.

(7) *CAA Section 111(d) EGU Rule Website*. You must include in your plan information about the establishment of a publicly accessible "CAA Section 111(d) EGU Rule Website" and requirements for the owners or operators of affected EGUs to post relevant documents to this website. State plans must require affected EGUs to post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. State plans must also require affected EGUs with increments of progress to post those increments, the schedule required in the state plan for achieving them, and any documentation necessary to demonstrate that they have been achieved to this website in a timely manner. State plans must require affected EGUs to post a report of any deviation from any federally enforceable increment of progress or milestone to this website in a timely manner.

(b) You must follow the requirements of subpart Ba of this part and demonstrate that they were met in your State plan.

§ 60.5760b What are the timing requirements for submitting my State plan?

(a) You must submit a State plan with the information required under § 60.5740b by [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE].

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

§ 60.5775b What standards of performance must I include in my plan?

(a) Standard(s) of performance for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.
(2) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.
(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an emission standard in another State plan.
(4) An affected EGU's standard of performance is permanent if the emission standard must be met continuously, unless it is replaced by another emission standard in an approved plan revision, or the State demonstrates in an approvable plan revision.
(5) An affected EGU's standard of performance is enforceable if:
    (i) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;
    (ii) Compliance requirements are clearly defined;
    (iii) The affected EGUs are responsible for compliance and liable for violations can be identified;
    (iv) Each compliance activity or measure is enforceable as a practical matter, as defined by 40 CFR 49.167; and
    (v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)-(h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

(b) *Subcategories of affected EGUs*. States must subcategorize existing fossil fuel-fired steam generating units into one of the following subcategories:

(1) Long-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that have not adopted a federally enforceable commitment to cease operations by January 1, 2040.
(2) Medium-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that choose to adopt a federally enforceable commitment to cease operations after December 31, 2031, and before January 1, 2040, and that are not near-term units.
(3) Near-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that choose to adopt federally enforceable commitments to cease operations after December 31, 2031, and before January 1, 2035, and to operate with annual capacity factors less than 20 percent.
(4) Imminent-term existing coal-fired steam generating units, consisting of coal-fired steam generating units that choose to adopt a federally enforceable commitment to cease operations before January 1, 2032.

(5) *Base load continental existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.
(6) *Intermediate load continental existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
(7) *Low load (continental and non-continental) existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.
(8) *Intermediate and base load non-continental existing oil-fired steam generating units,* consisting of non-continental oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent.
(9) *Base load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent
(10) *Intermediate load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
(11) *Low load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.

(c) Methodology for establishing presumptively approvable standards of performance, or presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term existing coal-fired steam generating units
  (i) BSER is CCS with 90 percent capture of CO_2.
  (ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
(2) Medium-term existing coal-fired steam generating units
  (i) BSER is natural gas co-firing at 40 percent of the heat input to the unit
  (ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is a 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline
  (iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, states must account for such preexisting co-firing in adjusting the degree of emission limitation (e.g., for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 30 percent to reflect the preexisting level of natural gas co-firing).
(3) Near-term existing coal-fired steam generating units
  (i) BSER is routine methods of operation
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline
(4) Imminent-term existing coal-fired steam generating units
  (i) BSER is routine methods of operation
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline
(5) Base load continental existing oil-fired steam generating units

(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,300 lb CO_2/MWh-gross

(6) Intermediate load continental existing oil-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,500 lb CO_2/MWh-gross

(7) Low load (continental and non-continental) existing oil-fired steam generating units do not have requirements.

(8) Intermediate and base load non-continental existing oil-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
(iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline

(9) Base load existing natural gas-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,300 lb CO_2/MWh-gross

(10) Intermediate load existing natural gas-fired steam generating units
(i) BSER is routine methods of operation and maintenance
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,500 lb CO_2/MWh-gross

(11) Low load existing natural gas-fired steam generating units do not have requirements.

(d) Methodology for establishing baseline emission performance for each affected EGU.

(1) A state shall use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5 years immediately prior to [INSERT DATE OF PUBLICATION OF FINAL RULE], based on the NSR/PSD program's definition of "baseline actual emissions" for existing electric steam generating units. See 40 CFR 52.21(b)(48)(i).

(2) Although eight quarters of 40 CFR part 75 data corresponds to a 2-year calendar period (and corresponds to quarterly reporting), states shall utilize the most representative continuous 8-quarter period of data from the 5 years immediately preceding [INSERT DATE OF PUBLICATION OF FINAL RULE].

(3) For the continuous 8 quarters of data, a state shall divide the total CO_2 emissions (in the form of pounds) over that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh.

(e) *Remaining Useful Life and Other Factors (RULOF).* CAA section 111(d)(1)(B) permits states to take into consideration a particular affected EGU's RULOF when applying a standard of performance to that source. A state may apply a less stringent standard of performance to an affected EGU when the state can demonstrate that the source cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA.

(1) A state may apply a less stringent standard of performance to a particular affected EGU, taking into consideration RULOF, provided that the state demonstrates with respect to that particular affected EGU that it cannot reasonably apply the BSER to achieve the degree of emission limitation determined via the methodology in subsection (c) of this section, based on one of more of three circumstances:

(i) unreasonable cost of control resulting from plant age, location, or basic process design;

(ii) physical impossibility or technical infeasibility of installing necessary control equipment; or

(iii) other circumstances specific to the facility that are fundamentally different from the information considered in the determination of the BSER.

(2) A state may not invoke RULOF based on minor, non-fundamental differences between a particular affected EGU and the degree of emission limitation determined via the methodology in subsection (c) of this section. For example, there could be instances in which an affected EGU may not be able to comply with the presumptively approvable standard of performance based on the precise metrics of the BSER determination but is able to do so within a reasonable margin.

(3) States invoking RULOF for affected coal-fired EGUs in the long-term subcategory must evaluate natural gas co-firing as a potential source-specific BSER. Additionally, if an EGU in the long-term subcategory can implement CCS but cannot achieve the degree of emission limitation prescribed by the presumptive standard of performance, the state must evaluate CCS with a source-specific degree of emission limitation as a potential BSER.

(4) States invoking RULOF for affected coal-fired EGUs in the long-term and medium-term subcategories must evaluate different levels of natural gas co-firing. The state must evaluate lower levels of natural gas co-firing unless it has demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. States may also consider additional potential source-specific BSERs for affected EGUs in either subcategory.

(5) Pursuant to the requirement to consider the potential pollution impacts and benefits for impacted communities, state plan submissions must demonstrate that the state considered where and how a less stringent standard of performance impacts these communities. The plan submission must clearly identify impacted communities and how it determined which communities were considered. In evaluating potential source-specific BSERs, a state must describe the health and environmental impacts anticipated from each control option it considered. A state must document how it considered these impacts, including any health and environmental benefits of control options, in determining the source-specific BSER. A state must consider and include in its state plan submission any feedback received during meaningful engagement regarding any proposed RULOF standard of performance for an affected EGU.

§ 60.5785b What is the procedure for revising my plan?

EPA-approved State plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart Ba of this part. If one (or more) of the elements of the plan set in § 60.5740b require revision, a request must be submitted to the Administrator indicating the proposed revisions to the plan.

Applicability of Plans to Affected EGUs

§ 60.5840b Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, affected EGU owners or operators must comply with the plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a State plan to implement and enforce the emission guidelines contained in this subpart by [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE], or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State that commenced construction on or before January 8, 2014.

§ 60.5845b What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected steam generating unit that was in operation or had commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraph (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

§ 60.5850b What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) EGUs that are subject to subpart TTTT or TTTTa of this part as a result of commencing construction after the subpart TTTT or TTTTa applicability date;

(b) Steam generating units subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output or 219,000 MWh;

(c) Non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(d) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(e) Units that serve a generator along with other steam generating unit(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less;

(f) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(g) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(h) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (8) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet emission standards must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, only "valid operating hours,", *i.e.,* full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in § 60.5880b) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data,and

(ii) The corresponding hourly gross energy output value is also valid data (**Note:** For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based emission standards, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage (CCS)), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each “valid operating hour” (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(5) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an

hourly basis useful thermal output and, if applicable, mechanical output, which are used with gross electric output to determine grossenergy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine P_{net} the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{\mathrm{TDF}} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

WHERE:
P_{NET} = NET ENERGY OUTPUT OF YOUR AFFECTED EGU FOR EACH VALID OPERATING HOUR (AS DEFINED IN 60.5860(A)(2)) IN MWH.
$(PE)_{ST}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STEAM TURBINES IN MWH.
$(PE)_{CT}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STATIONARY COMBUSTION TURBINE(S) IN MWH.
$(PE)_{IE}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF YOUR AFFECTED EGU'S INTEGRATED EQUIPMENT THAT PROVIDES ELECTRICITY OR MECHANICAL ENERGY TO THE AFFECTED EGU OR AUXILIARY EQUIPMENT IN MWH.
$(PE)_{A}$ = ELECTRIC ENERGY USED FOR ANY AUXILIARY LOADS IN MWH.
$(PT)_{PS}$ = USEFUL THERMAL OUTPUT OF STEAM (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) THAT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU. THIS IS CALCULATED USING THE EQUATION SPECIFIED IN PARAGRAPH (A)(5)(V) OF THIS SECTION IN MWH.
$(PT)_{HR}$ = NON-STEAM USEFUL THERMAL OUTPUT (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM HEAT RECOVERY THAT IS USED FOR APPLICATIONS OTHER THAN STEAM GENERATION OR PERFORMANCE ENHANCEMENT OF THE AFFECTED EGU IN MWH.
$(PT)_{IE}$ = USEFUL THERMAL OUTPUT (RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM ANY INTEGRATED EQUIPMENT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL STEAM, ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU IN MWH.
TDF = ELECTRIC TRANSMISSION AND DISTRIBUTION FACTOR OF 0.95 FOR A COMBINED HEAT AND POWER AFFECTED EGU WHERE AT LEAST ON AN ANNUAL BASIS 20.0 PERCENT OF THE TOTAL GROSS OR NET ENERGY OUTPUT CONSISTS OF ELECTRIC OR DIRECT MECHANICAL OUTPUT AND 20.0 PERCENT OF THE TOTAL NET ENERGY OUTPUT CONSIST OF USEFUL THERMAL OUTPUT ON A 12-OPERATING MONTH ROLLING AVERAGE BASIS, OR 1.0 FOR ALL OTHER AFFECTED EGUS.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

WHERE:
Q_M = MEASURED STEAM FLOW IN KILOGRAMS (KG) (OR POUNDS (LBS)) FOR THE OPERATING HOUR.
H = ENTHALPY OF THE STEAM AT MEASURED TEMPERATURE AND PRESSURE (RELATIVE TO SATP CONDITIONS OR THE ENERGY IN THE CONDENSATE RETURN LINE, AS APPLICABLE) IN JOULES PER KILOGRAM (J/KG) (OR BTU/LB).
CF = CONVERSION FACTOR OF 3.6 X 10^9 J/MWH OR 3.413 X 10^6 BTU/MWH.

(vi) For rate-based standards, sum all of the values of P_{net} for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values for the valid operating hours to determine the CO_2 emissions rate (lb/net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) Consistent with § 60.5775b or § 60.5780b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) [Reserved]

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or

record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you the information in paragraphs (d)(1) through (4) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour;

(ii) The net electric output and the net energy output (P_{net}) values for each valid operating hour;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours; and

(v) The calculated CO_2 mass emission rate (lbs/net MWh).

(3) [Reserved]

(4) For each affected EGU the report must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate in units of the emission standard.

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under § 60.5740b if applicable.

(f) If an affected EGU captures CO_2 to meet the applicable emission limit, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98 subpart RR or subpart VV, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR or subpart VV, if injection occurs off-site.

Recordkeeping and Reporting Requirements

§ 60.5865b What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 10 years from the date the record is used to determine compliance with an emissions standard or plan requirement. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5875b How do I submit information required by these emission guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE] deadline for plan submittal so that the official will have the ability to submit the initial or final plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

Definitions

§ 60.5880b What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, Ba, TTTT, and TTTTa, of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5845b.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal-fired steam generating unit means an electric utility steam generating unit or IGCC unit that meets the definition of “fossil fuel-fired” and that burns coal for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as “cogeneration”) means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired or oil-fired steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means: (1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to standard ambient temperature and pressure conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Oil-fired steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.4, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.