Small Entity Compliance Guide

For

Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

40 CFR Part 60, Subpart TTTTa

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40 CFR Part 60, Subpart TTTTa

U.S. Environmental Protection Agency

Office of Air Quality Planning and Standards

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Note – This version (Version 2.0, August 2024) of the Small Entity Compliance Guide is an update to make corrections to minor errors that were included in the original version.

Shown below are a list of edits included in this version:

- Expanded the definitions box to display the entire definition for IGCC facilities on page 13
- Deleted a broken cross-reference in the first paragraph of 3.2.2 on page 20
- Corrected “if” to “of” in the description of Pt_{IE} on page 27
- Replaced “are” to “your EGU is” at the end of the first paragraph of 4.3.8 on page 31
- Moved the regulatory text citation at the end of the last paragraph inside the period on page 37
- Deleted “required” from the last sentence of the first paragraph on page 38
- Moved “depending on the specific parameter” from the middle of the first sentence of the first paragraph to the end of the sentence on page 40

Forward

This guide was prepared pursuant to section 212 of the Small Business Regulatory Enforcement Fairness Act of 1996 ("SBREFA"), Public Law 104-121, as amended by Public Law 110-28. THIS DOCUMENT IS NOT INTENDED, NOR CAN IT BE RELIED UPON, TO CREATE RIGHTS ENFORCEABLE BY ANY PARTY IN LITIGATION WITH THE UNITED STATES. Final authority rests with the regulation at 40 Code of Federal Regulations (CFR) part 60, subpart TTTTa, and this guide is not intended to replace, and may not cover all parts of, this regulation.

The statements in this document are intended solely to aid regulated entities in complying with the published national regulation "Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units." The final rule was published on May 9, 2024 (89 FR 39798), for Title 40 of the Code of Federal Regulations (40 CFR) Part 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units.

This guide addresses the requirements of subpart TTTTa, which applies to stationary combustion turbines that commenced construction or reconstruction after May 23, 2023, and coal-fired steam generating units or integrated gasification combined cycle (IGCC) facilities that commenced modification after May 23, 2023.

While this guide concerns subpart TTTTa, which includes the standards of performance for modified coal-fired steam generating units and new construction and reconstruction stationary combustion turbines, as part of the larger package, separate requirements were published for existing steam generating units in 40 CFR part 60 subpart TTTT and 40 CFR part 60 subpart UUUUb. This guide does not address the requirements from those other subparts.

The U.S. Environmental Protection Agency (EPA) may decide to revise this guide without public notice to reflect changes in the EPA's approach to implementing the rule's requirements or to clarify and update text. To determine whether the EPA has revised this guide and/or to obtain copies, contact Lisa Thompson at thompson.lisa@epa.gov or Daniel Parker at parker.daniel@epa.gov.

The full rule text is available online at:

https://www.federalregister.gov/documents/2024/05/09/2024-09233/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed

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Section 1. Introduction

This document was prepared by the EPA as a compliance guide for small entities subject to the Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units (40 CFR part 60 subpart TTTTa) as required by the Small Business Regulatory Enforcement Act of 1996 (SBREFA). Before you begin using this guide, remember that the information it contains was originally compiled and published in July 2024. The EPA is continually improving and updating its rules, policies, compliance programs, and outreach efforts. You can determine whether the EPA has revised or supplemented the information in this guide by checking the Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants web page for the rule, which also features supporting information including fact sheets and technical support documents.

The final Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units – referred to as "the rule" or "NSPS TTTTa" in this document – was signed by the EPA Administrator on April 24, 2024, and published in the *Federal Register* on May 9, 2024.

The rule's effective date is July 8, 2024, to allow 60 days for U.S. Congressional review after its publication. On that effective date, the requirements in the rule became law. The information in this guide was compiled to assist small business entities subject to the rule to better understand its requirements. Throughout the guide, regulated entities are referred to specific sections of the rule for details related to their compliance requirements.

A complete copy of the rule can be found in the *Federal Register* (89 FR 39798; May 9, 2024) while the codification of the final rule's subpart can be found in the electronic CFR (eCFR): Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, at https://www.ecfr.gov/. The docket for this rule, which includes other relevant files, such as technical support documents and public comments, is available at https://www.regulations.gov/, docket ID number: EPA-HQ-OAR-2023-0072.

1.1 What environmental/human health issues does this rule address and why are they important?

This final rule includes performance standards for greenhouse gas (GHG) emissions in the form of limitations on carbon dioxide (CO_2), a significant contributor to climate change. In addition to raising global temperatures, climate change is expected to cause, among others, more frequent and more intense heat waves and extreme weather events, rising sea levels, and retreating snow and ice. These impacts increase the potential for deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Additionally, climate change is expected to result in additional respiratory illnesses, such as asthma.

1.2 What does this guide cover?

This guide covers the affected facilities under the subpart TTTTa rule: stationary combustion turbines that commenced construction or reconstruction after May 23, 2023, and coal-fired steam generating units or integrated gasification combined cycle facilities that commenced modification after May 23, 2023. Although the intended audience for this guide is small business entities, this compliance guide will likely be useful to all entities subject to the rule.

1.3 Structure and content of the guide

Part 1 contains introductory information about this guide and general information about the subpart TTTTa rule, its applicability, and its requirements. Parts 2 through 7 discuss in more detail the specific requirements of the rule including applicability, compliance, monitoring, and recordkeeping requirements. This guide provides a general description of the requirements of the final rule in a simplified format and includes citations to the appropriate regulatory text throughout the guide. The full citation for each section of regulatory text in this rule would include “40 CFR” and “(2024)” but those have not been included in this guide for ease of reading. It is important to note that references to this “subpart” refer to 40 CFR part 60, subpart TTTTa, unless otherwise specified.

1.4 Acronyms and abbreviations

The table below provides a list of acronyms and abbreviations that are used in this guide along with their corresponding full name.

Acronym	Full Name
ADR	Alternate Designated Representative
BSER	Best system of emissions reduction
Btu	British thermal unit
CAA	Clean Air Act
CCS	Carbon capture and sequestration/storage
CEMS	Continuous emission monitoring system
CFR	Code of Federal Regulations
CHP	Combined heat and power
CO_2	Carbon dioxide
DR	Designated Representative
eCFR	Electronic Code of Federal Regulations
ECMPS	Emissions Collection and Monitoring Plan System
EGU	Electric generating unit
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
GHG	greenhouse gas
GJ	Gigajoule
GW	Gigawatt
GWh	gigawatt-hour
IGCC	Integrated gasification combined cycle
kg	Kilogram
kWh	kilowatt-hour
lb	Pound
MMBtu	million British thermal units
MW	Megawatt
MWh	megawatt-hour
NSPS	new source performance standards
RATA	Relative accuracy test audit
SBREFA	Small Business Regulatory Enforcement Fairness Act

Table 1. Acronyms used in this guide.

Section 2. Applicability

2.1 Am I subject to this rule?

You are subject to NSPS TTTTa if you own or operate a fossil fuel-fired stationary combustion turbine that commences construction or reconstruction after May 23, 2023, or a fossil fuel-fired steam generating unit or IGCC that combusts coal (or fossil-derived syngas) and that commences modification after May 23, 2023, that:

- Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel) [§60.5509a(a)(1)]; and
- Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system [§60.5509a(a)(2)].

Definitions

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 (e.g., onsite photovoltaics), integrated energy storage (e.g., onsite batteries), 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.

Coal-fired electric generating unit means a steam generating unit or IGCC unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

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 gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

The following sources are not subject to NSPS TTTTa [§60.5509a(b)]:

- A steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 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.
- An EGU 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 or less.
- A CHP 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.
- An EGU that 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.
- A municipal waste combustor that is subject to subpart Eb of this part.
- A commercial or industrial solid water incineration unit that is subject to subpart CCCC of this part.
- 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. 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.
- An EGU that 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.

Figure 1. Subpart TTTTa applicability exemption criteria

2.2 What subcategories are established in this rule?

Coal-fired electric generating units and IGCC facilities are not subcategorized in NSPS TTTTa.

Stationary combustion turbines are divided into three subcategories in this rule: base load, intermediate load, and low load. These subcategories are based on potential electric output and net-electric sales thresholds. [§60.5580a].

Base load combustion turbine

- A stationary combustion turbine that supplies more that 40 percent of its potential electric output as net-electric sales on both a 12-operating month and 3-year rolling average basis.

Intermediate load combustion turbine

- A stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Low load combustion turbine

- A stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Figure 2. Combustion turbine subcategories

Definition

Potential electric output means the base load rating design efficiency at the maximum electric production rate multiplied by the base load rating 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 hours/year.

Consider the following example EGU with a 341 MMBtu/hr base load rating heat input capacity and a 35% design efficiency. It would have a 12-month potential electric output capacity of approximately 306,000 MWh, as illustrated below.

$$341\,\frac{MMBtu}{hr} \times \frac{10^6 Btu}{1\,MMBtu} \times \frac{1\,kWh}{3{,}413\,Btu} \times \frac{1\,MWh}{1000\,kWh} \times \frac{8{,}760\,hrs}{1\,year} \times 35\% \quad = {\sim}306{,}000\,MWh$$

The definition of net-electric sales has a few parts, some of which depend on whether the affected EGU is a combined heat and power (CHP) facility.

Definition

Net electric sales means:

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

(2) For CHP facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month 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 during a system emergency are not included when calculating net-electric sales.

Consider the following example 100 MW CHP facility with an 80% capacity factor, that sells 100% of the generated electricity to the electric grid, and that supplies 50% of the thermal host's thermal demand.

This is how that CHP facility would calculate its net-electric sales:

In one year of operation, the CHP facility would generate 700,800 MWh of electricity in total that is sold to the electric grid.

$$100\,MW \times \frac{24\,hours}{1\,day} \times \frac{365\,days}{1\,year} \times 80\% = 700{,}800\,MWh$$

During the year, the thermal host purchased 350,400 MWh of electricity from the electric grid. Since the CHP facility is supplying 50% of the thermal host's thermal demand, 50% of the electricity purchased by the thermal host is subtracted from the total electricity generated.

The CHP facility's net electric sales are 525,600 MWh.

$$700{,}800\ MWh - (350{,}400\ MWh \times 50\%)\ = 525{,}600\ MWh$$

Section 3. Emission Standards

3.1 What does the regulation require?

The Clean Air Act (CAA) requires the EPA to set New Source Performance Standards (NSPS) for industrial categories that cause or significantly contribute to air pollution that may endanger public health or welfare. The rule establishes emission control standards for fossil-fuel fired electric generating units (EGUs) for GHGs (represented as CO_2). Fossil-fuel fired EGUs are the largest stationary source of GHG emissions in the United States. In 2021, fossil-fuel fired EGUs accounted for 25 percent of overall domestic CO_2 emissions.

The emission standards established by this rule reflect the application of the best system of emissions reduction (BSER) for each EGU type, as listed below.

Modified coal-fired steam generating units or IGCC facilities*

- **All affected EGUs in this category**: Carbon capture and sequestration (CCS) with a 90 percent capture rate

New or reconstructed stationary combustion turbines

- **Base load - Phase 1**: Highly efficient generation
- **Base load - Phase 2**: CCS with a 90 percent capture rate and highly efficient generation
- **Intermediate load**: Highly efficient simple cycle generation
- **Low load**: Lower-emitting fuels

Figure 3. Summary of subpart TTTTa control requirements.

* At the same time as this NSPS, the EPA issued emission guidelines for existing coal-fired EGUs. For more information on those, see 40 CFR Part 60, Subpart UUUUb.

3.2 Stationary Combustion Turbines

3.2.1 Base Load Subcategory

The relevant CO_2 emission standards for stationary combustion turbines depend on the subcategory.

For combustion turbines within the base load subcategory, there are two phases of emission standards: those in effect before January 2032, and those in effect after December 2031.

Base Load - Phase 1 (12-operating month averages beginning before January 2032)

- **Gross energy output basis**: 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh); or
- **Net energy output basis**: 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh)*

Base Load - Phase 2 (12-operating month averages beginning after December 2031)

- **Gross energy output basis**: 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh); or
- **Net energy output basis**: 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh)*

Figure 4. Base load stationary combustion turbine CO_2 emission standards by phase.

*Indicates standards calculated using the procedures listed in section 4.1 of this guide.

3.2.2 Intermediate and Low Load Subcategories

The CO_2 emission standards for stationary combustion turbines in the intermediate and low load subcategories are listed below (Table 1 to Subpart TTTTa).

Intermediate Load

- **Gross energy output basis**: 530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh); or
- **Net energy output basis**: 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh)*

Low Load

- **Heat input basis**: between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu)*

Figure 5. Intermediate and low load stationary combustion turbine CO_2 emission standards.

*Indicates standards calculated using the procedures listed in section 4.1 of this guide.

3.3 Coal-fired Steam Generating Units and IGCC Facilities

The CO_2 emission standard for modified coal-fired steam generating units and IGCC facilities is listed below (Table 2 to Subpart TTTTa).

Modified Coal-Fired Steam Generating Unit or IGCC

- a unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification)

Figure 6. CO_2 emission standard for coal-fired steam generating units or IGCC facilities.

Section 4. Compliance

4.1 What are my general requirements for complying with subpart TTTTa?

Your affected EGU must not discharge gases that contain CO_2 in excess of the applicable emission standard in Table 1 to this subpart [§60.5520a(a)].

In general, the emission standard is based on gross energy output and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on that applicable standard [§60.5520a(a)].

You may petition the Administrator in writing to comply with the alternate applicable net energy output-based standard instead. If granted, starting on that date, your affected EGU must comply with the applicable net energy output-based standard and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on that standard. To switch back to being subject to the gross energy output-based standard, you must petition the Administrator again [§60.5520a(c)].

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. [§60.5525a(a)].

4.1.1 What if my affected EGU burns uniform fuels?

If your combustion turbine is only permitted to burn uniform fuels, you must maintain fuel purchase records to comply [§60.5525a(a)].

These uniform fuels include but are not limited to [§60.5520a(c)]:

- Hydrogen
- Natural gas
- Methane
- Butane
- Butylene
- Ethane
- Ethylene
- Propane
- Naphtha
- Propylene
- Jet fuel
- Kerosene
- No. 1 fuel oil
- No. 2 fuel oil
- Biodiesel

4.1.2 What if my affected EGU does not burn uniform fuels?

Otherwise, you must determine your compliance monthly by calculating the average CO_2 emissions rate for each 12-operating month period using one of the following equations [§60.5525a(a)(1)]:

- 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) and described in section 5.2 of this guide. You must then use the following equation to determine the applicable emissions standard during the compliance period [§60.5525a(a)(2)]:

$$CO_2\ emission\ standard = \frac{(50\ \times HTIP_{ng}) + (69\ \times\ HTIP_o)}{HTIP_{ng} +\ HTIP_o}$$

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).

- If your affected EGU is either: 1) a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) or 2) a base load combustion turbine burning fuels other than natural gas, you may elect to determine a site-specific emissions rate using the following equation. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter [§60.5525a(a)(3)(i)].

$$CO_2\ emission\ standard = \left[BLER_L + \frac{BLER_S - BLER_L}{BLR_L - BLR_S} \times (BLR_L - BLR_A)\right] \times \left[\frac{HIER_A}{HIER_{NG}}\right]$$

Where:

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

$BLER_L$ = Base load emission standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h):

- 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); or
- 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = base load emission 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); or
- 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

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)

- If your affected EGU is an intermediate load combustion turbine burning fuels other than natural gas, you may elect to determine a site-specific emission rate using the following equation. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter [§60.5525a(a)(3)(ii)].

$$CO_2\ emission\ standard = ILER \times \left[\frac{HIER_A}{HIER_{NG}}\right]$$

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 CO_2 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 CO_2/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)

In addition, 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 your EGU [§60.5525a(b)].

4.2 When must I make my initial compliance determination?

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 ends), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard [§60.5525a(c)].

The first month of the initial compliance period shall be the first **operating month** after the calendar month in which emissions reporting is required to begin.

The specific month when reporting begins depends on whether your EGU is already in operation and whether your EGU is subject to the Acid Rain Program:

- For newly constructed EGUs that are subject to the Acid Rain Program, the first month reporting is required is the month your EGU is provisionally certified or 180 days after the date your EGU commences commercial operation, whichever is earlier [§60.5525a(c)(1)(i)].
- For newly constructed EGUs that are not subject to the Acid Rain Program, the first month reporting that is required is either the date of provisional certification or the deadline for initial certification, whichever is earlier, if that date occurs after May 23, 2023 [§60.5525a(c)(1)(ii)].
- For reconstructed or modified EGUs, reporting must begin on the date that the EGU becomes subject to subpart TTTTa [§60.5525a(c)(2)].

Definition

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

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

If your affected EGU is subject to an output-based emission standard or burns non-uniform fuels, you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 to subpart TTTTa according to the procedures described in §60.5540a and described in this section.

In general, this requires using hourly CO_2 mass emissions values and either generating load data for output-based standards or heat input data for heat input-based standards to calculate your EGU's CO_2 emission rate.

For combustion turbines that fire non-uniform fuels which contain CO_2 before combustion, you may sample the fuel stream to determine the amount of CO_2 present prior to combustion and exclude that portion from the compliance determinations.

4.3.1 What data can I use to perform my calculations?

Each 12-operating month compliance period only includes "valid operating hours" in that compliance period [§60.5540a(a)(1)(i) and (ii)]. These are operating hours for which:

- Valid data are obtained for all parameters used to determine the hourly CO_2 mass emissions and, if a heat-input based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and
- The corresponding hourly gross or net energy output value is also valid data. (Note: for hours with no useful output, zero is considered a valid value).

You must exclude operating hours in which:

- The substitute data provisions of part 75 are applied for any of the parameters used to determine the hourly CO_2 mass emission or, if a heat-input base standard applies, for any parameters used to determine the hourly heat input [§60.5540a(2)(i)];
- An exceedance of the full-scale range of a CEMS occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input [§60.5540a(2)(ii)]; or
- The total gross or net energy output, or if applicable, the total heat input, is unavailable [§60.5540a(2)(iii)].

For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours [§60.5540a(a)(3)].

You must calculate your EGU's total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values that you previously calculated for all the valid operating hours in the compliance period [§60.5540a(a)(4)].

4.3.2 How do I calculate my EGU's hourly gross or net energy output?

For each valid operating hour of the compliance period, you must determine the hourly gross or net energy output according to the equations below, as appropriate.

You must still determine the gross or net energy output for the hour even if there is valid CO_2 emissions data and mechanical or useful thermal output but no electrical output. Even if there is no electrical, mechanical, or thermal output, if there is valid CO_2 emissions data, you must use that hour in your compliance determinations.

For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output should be considered zero [§60.5540a(a)(5)].

You must use the following equation to calculate hourly gross or net energy output of your affected EGU. All terms must be in units of MWh and to convert output values to MWh, multiply them by the corresponding EGU or stack operating time [§60.5540a(a)(5)(i)].

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

Where:

$P_{gross/net}$ = Gross or net energy output of your affected EGU for each valid operating hour 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 that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of your affected EGU. (This is calculated using the equation below.)

$(Pt)_{HR}$ = Non steam useful thermal output 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 from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of your 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.

If you must calculate the useful thermal output of steam (for example, if your EGU is a CHP facility), use the following equation [§60.5540a(a)(5)(ii)]:

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

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: 3.6×10^9 J/MWh or 3.143×10^6 Btu/MWh.

4.3.3 How do I calculate my EGU's total energy output or heat input?

If your EGU is subject to an output-based standard, you must calculate the total gross or net energy output by summing the hourly gross or net energy output values using the above equation(s) for all the valid operating hours in the applicable compliance period [§60.5540a(a)(6)(i)].

If your EGU is subject to a heat-input based standard, you must calculate the total heat input for each fuel fired during the compliance period. The total heat input must include all valid operating hours and be consistent with any fuel-specific procedures as previously discussed for non-uniform fuels in section 5.2 of this guide [§60.5540a(a)(6)(ii)].

4.3.4 How do I calculate my EGU's CO_2 mass emissions rate?

If your EGU is subject to an output-based standard, you must calculate your EGU's CO_2 mass emissions rate by dividing the total CO_2 mass emissions value by the total gross or net energy output value.

There are also specific directions about rounding:

- If the resulting value is less than 1,000, round the result to two significant figures; or
- If the resulting value is greater than 1,000, round the result to three significant figures.

If your EGU is subject to an input-based standard, you must calculate your EGU's CO_2 mass emissions by dividing the total CO_2 mass emissions by the total heat input. No matter the resulting value, round this result to two significant figures [§60.5540a(a)(7)].

4.3.5 How do I calculate my emission rate when moving between Phase 1 and 2?

If your EGU operates in the base load subcategory from 2031 to 2032, its emission standard will change based on the move from phase 1 to phase 2. The emission standards in phase 1 apply to the 12-operating month averages that begin before January 2032 while the emission standards in phase 2 apply for 12-operating month averages that begin after December 2031.

This means that while the phase 2 emission standards will apply to each month after December 2031, the first compliance determination that would be entirely based on the new emission standards would be in December 2032, as the table below illustrates.

Year	Month	Which phase's emission standard is in effect for the month?	Which phase's emission standard is in effect for the 12-operating month compliance period?	12-Operating Month Compliance Period
2031	11	1	1	12/2030 - 11/2031
2031	12	1	1	1/2031 - 12/2031
2032	1	2	1	2/2031 - 1/2032
2032	2	2	1	3/2031 - 2/2032
2032	3	2	1	4/2031 - 3/2032
2032	4	2	1	5/2031 - 4/2032
2032	5	2	1	6/2031 - 5/2032
2032	6	2	1	7/2031 - 6/2032
2032	7	2	1	8/2031 - 7/2032
2032	8	2	1	9/2031 - 8/2032
2032	9	2	1	10/2031 - 9/2032
2032	10	2	1	11/2031 - 10/2032
2032	11	2	1	12/2031 - 11/2032
2032	12	2	2	1/2032 - 12/2032
2033	1	2	2	2/2032 - 1/2023
2033	2	2	2	3/2032 - 2/2033

Table 2. Base load subcategory phases and compliance periods.

4.3.6 How does operating in a system emergency affect my calculations?

If your affected EGU operates during a system emergency and you can provide sufficient records to document that, you can exclude CO_2 mass emissions and output generated during that system emergency from your calculations [§60.5540a(a)(8)].

These records include:

- Documentation that the system emergency to which your EGU was responding was in effect from the entity that issued the alert and documentation of the exact duration of the system emergency [§60.5560a(i)(1)];
- Documentation from the entity issuing the alert that the system emergency included the area where your EGU was located [§60.5560a(i)(2)]; and
- Documentation that your EGU was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability

Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization [§60.5560a(i)(3)].

There is also an alternate emission standard for operation during a documented system emergency depending on the subcategory or unit type:

- If your EGU is in the intermediate or base load subcategory, your CO_2 emission standard while operating in a system emergency is the applicable emission standard for low load combustion turbines [§60.5540a(a)(8)(i)].
- If your EGU is a modified steam generating unit, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu [§60.5540a(a)(8)(ii)].

4.3.7 How can I determine if my EGU is in compliance with the applicable emission standard?

You can determine if your EGU is in compliance with the applicable CO_2 emission standard by calculating your EGU's CO_2 mass emissions rate according to the above equations and comparing that value to the applicable emissions standard in Table 1 to this subpart or the emissions standard that you calculated using the equation in section 4.1.2 of this guide. Your EGU is in compliance if the emissions rate you calculated is less than or equal to the applicable emission standard [§60.5540a(b)].

4.3.8 What is the compliance date extension?

A one-time compliance date extension of up to one year past the original compliance date is available for your new or reconstructed stationary combustion turbine(s) operating in the base load subcategory if, in the process of installing add-on controls and due to circumstances outside your control, your EGU is unable to meet the applicable phase 2 emission standard [§60.5540a(c)].

To apply for this extension, you must provide a demonstration of necessity that includes:

- Information to identify the unit [§60.5540a(c)(1)(i)];
- Identification and a description of controls to be installed at the unit [§60.5540a(c)(1)(ii)];
- A description and demonstration of progress in installing the controls [§60.5540a(c)(1)(iii)(A) and (B)];
- Identification of the circumstances beyond your control that necessitate additional time to complete installation [§60.5540a(c)(1)(iv)(A) through (C)]; and
- Identification of a proposed compliance date no later than one year after January 2032 [§60.5540a(c)(1)(v)].

The above information must be provided to the Administrator no less than 6 months ahead of time, and upon their review, the Administrator will approve or disapprove the request [§60.5540a(c)(2)].

Section 5. Monitoring

5.1 How do I monitor and collect CO_2 and heat input data for combustion turbines?

If your affected EGU is a combustion turbine that is only permitted to burn uniform fuels, as described in §60.5520a(d), your only requirement is to maintain fuel purchase records for permitted fuel(s) [§60.5535a(a)].

If your affected EGU does not burn uniform fuels, you must determine the hourly CO_2 mass emissions from your affected EGU(s) through one of the following options. You must also prepare a monitoring plan to quantify your affected EGU's hourly CO_2 mass emissions rate according to 40 CFR 75.53 (g) and (h), which list specific requirements for monitoring plans for EGUs that use CEMS. [§60.5535a(a)]:

1) If your affected EGU combusts coal, you must, but otherwise, you may, opt to install a continuous emission monitoring system (CEMS) to measure and record CO_2 emissions from your EGU's exhaust gas and a flow monitoring system to measure hourly average stack gas flow rates [§60.5535a(b)(1)].
   a) If you install CEMS, there are certification and quality assurance procedures that you must follow from 40 CFR 75.20 and appendices A and B to part 75 of this chapter [§60.5535a(b)(2)].
   b) You must also only use unadjusted exhaust gas volumetric flow rates in your calculations; this means not applying the bias adjustment factors to your gas flow rate data [§60.5535a(b)(3)].
   c) You must choose an appropriate reference method to characterize your flow monitor and to perform on-going relative accuracy test audits (RATAs). If you use a Type-S pitot tube or a pitot tube assembly, you must calibrate it rather than using the default coefficient specified in Method 2 [§60.5535a(b)(4)].
   d) There are also specific steps to calculate your CO_2 mass emissions rate using the data collected from your CEMS including only using data from **valid operating hours** and the specific steps to multiply each CO_2 hourly mass emission by the operating time and converting from tons to kg as well as a requirement to electronically report the values used to calculate the CO_2 mass emissions [§60.5535a(b)(5)].

Definition

Valid operating hours means:

1) Valid data (quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter) are obtained for all parameters used to determine the CO_2 mass emissions and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

2) 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) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, you may also determine hourly CO_2 mass emissions by:
   a) If you do not install a CEMS, you must determine hourly EGU heat input rates using hourly fuel flow rate measurements and periodic determinations of each combusted fuel's gross calorific value (GCV) using procedures from appendix D to part 75 [§60.5535a(c)(1)].
   b) Use Equation G-4 in appendix G to part 75 to calculate the hourly CO_2 mass emission rate. As part of this calculation, you may determine and use site-specific F-factors using Equation F-7b in section 3.3.6 of appendix F to part 75 instead of the default ones [§60.5535a(c)(2)].
   c) For each valid operating hour, multiply the hourly tons/h CO_2 mass emission rate by the EGU or stack operating time in hours to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures. [§60.5535a(c)(3)].
3) If you use non-uniform fuels, you may alternatively use one of the following methods:
   a) Determine heat input using the procedure in §60.107a(d), which lists requirements for monitoring emissions from fuel gas combustion devices and flares. This heat input may then be converted to CO_2 emissions using Equation G-4 in appendix G to part 75 [§60.5535a(c)(5)(i)]; or
   b) Determine CO_2 emissions using the Tier 3 methodology in 40 CFR 98.33(a)(3), which has methodologies for calculating GHG emissions [§60.5535a(c)(5)(ii)].

5.2 How do I determine the energy output or heat input basis of my affected EGU's emissions standard?

You must determine the basis of your affected EGU's emission standard depending on the basis of the emissions standard that applies to your affected source:

If you operate a source subject to an emissions standard established on an output basis (e.g., lb CO_2 per gross or net MWh of energy output), you must install enough watt meters to continuously measure and record the hourly gross or net electric output from your affected EGU. You must use 0.2 class electric meters and calibrate them according to ANSI No. C12.20-2010. If your affected EGU is a CHP unit, you must install meters to measure and record the total useful thermal output to use in your calculations. For process steam applications, you must install meters to measure and record the hourly steam flow rate, temperature, and pressure. In general, you must install, calibrate, maintain, and operate meters to record each component of your basis, hour-by-hour [§60.5535a(d)(1)].

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, you must determine the total heat input using one of the following procedures:

1) According to Appendix D to part 75, which has equations for calculating heat input rates for gaseous fuels [§60.5535a(d)(2)(i)];
2) Using the procedures for monitoring heat input under §60.107a(d), which has information about monitoring for fuel gas combustion devices and flares [§60.5535a(d)(2)(ii)]; or
3) If you monitor CO_2 emissions under the Tier 3 methodology in 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor according to Method 19 of appendix A-7 to part 60 and convert your CO_2 emissions to heat input using Equation G-4 in appendix G to part 75 [§60.5535a(d)(2)(iii)].

5.3 What if two or more affected EGUs serve a common electric generator?

If two or more of your affected EGUs serve a common electric generator, you must apportion their 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.

If the affected EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individuals EGUs according to the fraction of the total heat input contributed by each EGU.

You may develop alternate methods for apportioning the gross or net energy output and present them to the Administrator for approval. The Administrator may approve them if these alternate methods can demonstrate accurate emission estimates [§60.5535a(e)].

5.4 What if two or more affected EGUs share a common exhaust gas stack?

If two or more of your affected EGUs that use CEMS also share a common exhaust gas stack, you must monitor their hourly CO_2 mass emissions by:

1. If your affected EGUs are subject to the same emission standard, you may monitor the hourly CO_2 emissions at the common stack instead of monitoring each one individually. If you choose this option, the hourly gross or net energy output must be the sum of those values for each of the affected EGUs and the operating time must be noted as "stack operating hours." If you attain compliance for the applicable emissions standard at the common stack, each affected EGU sharing the stack is in compliance [§60.5535a(f)(1)]; or
2. As an alternative to the above or if your affected EGUs are subject to different emission standards, you must either:
    a. Monitor each affected EGU separately by measuring the hourly CO_2 mass emissions before they mix in the common stack [§60.5535a(f)(2)(i)]; or
    b. Apportion the CO_2 mass emissions based on each unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may develop alternate methods for apportioning the CO_2 emissions and present them to the Administrator for approval. The Administrator may approve them if these alternate methods can demonstrate accurate emission estimates [§60.5535a(f)(2)(ii)].

5.5 What if there are multiple exhaust stacks or multiple ducts are routed to a common stack?

If your affected EGU implements CEMS and the exhaust gases from your affected EGU are emitted to the atmosphere through multiple stacks, or if they are routed to a common stack through multiple ducts and you monitor in the ducts, you must monitor the hourly CO_2 mass emissions and the "stack operating time" (defined in 40 CFR 72.2) at each stack or duct separately. To determine compliance with the applicable emission standard, you must sum the CO_2 mass emissions measured at the individual stacks or ducts and divide that by the total gross or net energy output for your affected EGU [§60.5535a(g)].

Section 6. Notification, Reports, and Records

6.1 What notifications must I submit and when?

As applicable, you must prepare and submit the following notifications. [§60.5550a].

Notification requirements	Dates
Date of construction or reconstruction of an affected EGU	Postmarked no later than 30 days after such date [§60.7(a)(1)]
Actual date of initial startup of an affected EGU	Postmarked within 15 days after such date [§60.7(a)(3)]
Initial certification and recertification test for continuous emission monitoring systems, alternative monitoring systems, or excepted monitoring systems	Not later than 21 days prior to the first scheduled day of certification or recertification testing [§75.61(a)(1)]
New unit, newly affected unit, new stack, or new flue gas desulfurization system operation notification	No later than 45 days prior to the date the unit commences commercial operation or becomes affected, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere [§75.61(a)(2)]
Unit shutdown and recommencement of commercial operation	No later than 21 days prior to the applicable compliance date, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart [§75.61(a)(3)]
Use of backup fuels for appendix E procedures	No later than 45 days prior to the deadline in § 75.4 [§75.61(a)(4)]
Periodic relative accuracy test audits, appendix E retests, and low mass emissions unit retests	No later than 21 days prior to the first scheduled day of testing [§75.61(a)(5)]
Notice of combustion of emergency fuel under appendix D or E	For each calendar quarter in which emergency fuel is combusted [§75.61(a)(6)]
Long-term cold storage and recommencement of commercial operation	45 calendar days prior to the planned date of recommencement of commercial operation [§75.61(a)(7)]
Certification deadline date for new or newly affected units	No later than 7 calendar days after the applicable certification deadline is reached [§75.61(a)(8)]
Notification of certification tests and recertification tests for continuous opacity monitoring systems	As specified in § 75.20(c)(8) [§75.61(b)]

Table 3. Notification types and dates required by subpart TTTTa

6.2 What reports must I submit and when?

If your affected EGU is required to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports that must include, as applicable:

- Each rolling average CO_2 mass emissions rate, as calculated by the steps described in section 4.3 of this guide, for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter [§60.5555a(a)(2)(i)]
- 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) [§60.5555a(a)(2)(i)]
- 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, or a statement that your affected EGU did not violate its CO_2 emission standard in the relevant compliance period(s) [§60.5555a(2)(ii) and (iii)]
- The percentage of valid operating hours in each 12-operating month compliance period. This is calculated by dividing the total number of valid operating hours in that period by the total number of operating hours in that same period and multiplying that result by 100 percent [§60.5555a(2)(iv)]
- The CO_2 emission standard with which your affected EGU must comply [§60.5555a(2)(v)]
- An indication whether or not the hourly gross or net energy output used in your compliance determinations is based solely on gross electrical load [§60.5555a(2)(vi)].

The final quarterly report of each calendar year must also include:

- Your EGU's gross energy output or net energy output sold to the electric grid, depending on the units of your emission standard, over the four quarters in the calendar year [§60.5555a(3)(i)]; and
- Your affected EGU's potential electric output [§60.5555a(3)(ii)].

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 [§60.5555a(1)].

You must submit all electronic reports required 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 [§60.5555a(3)(b)]

If your affected EGU is subject to the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under §60.75 Subpart G. Affected EGUs that are not subject to the Acid Rain Program must also follow those additional requirements, where applicable, to the extent that those requirements and reports provide applicable data for the compliance demonstrations [§60.5555a(c)(1) and (2)].

The flow chart below demonstrates when you must initially begin submitting the quarterly reports [§60.5555a(c)(3)(i) through (iii)].

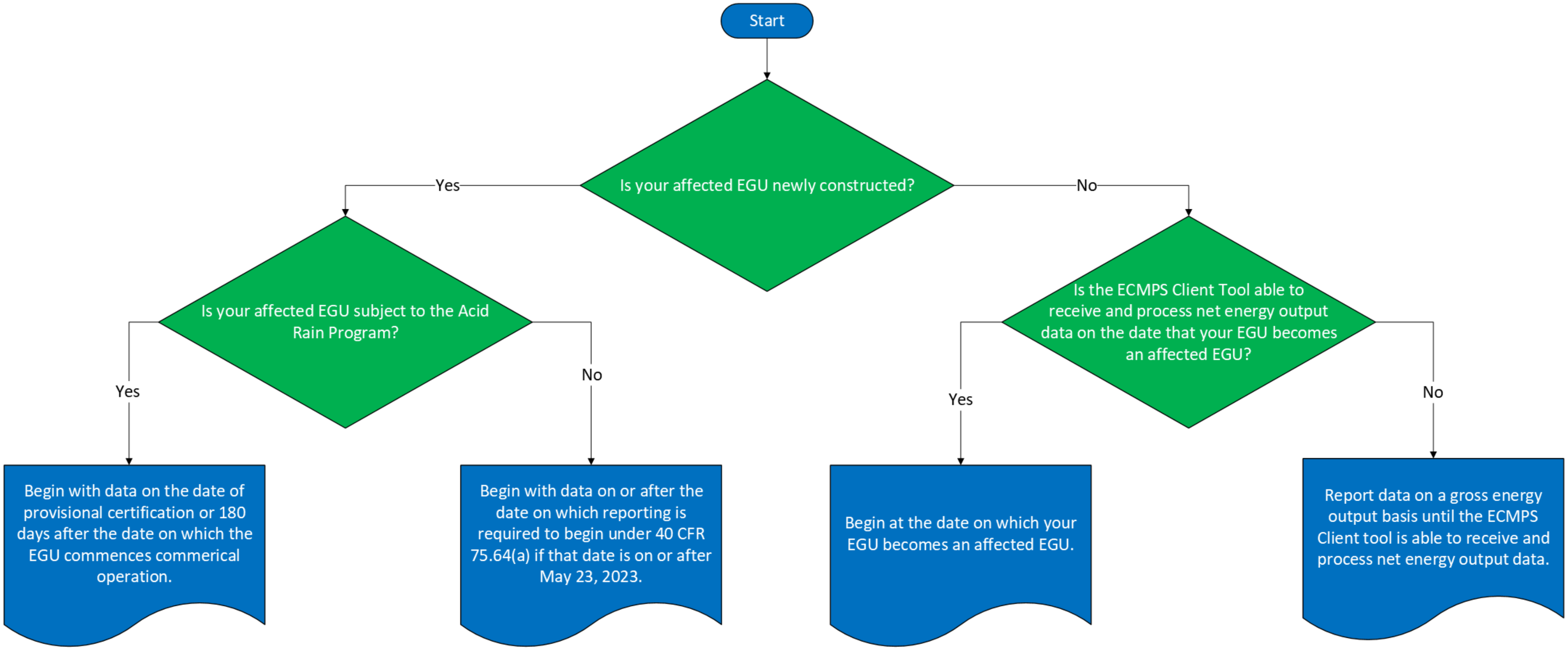

Figure 7. Initial data reporting flowchart.

If any required monitoring system has not been provisionally certified by the applicable date when emissions data reporting is required to begin, the maximum or minimum potential value measured by the monitoring system shall be reported until the certification testing is successfully completed, depending on the specific parameter. Operating hours in which CO_2 emission rates are calculated using these maximum potential values are not considered valid operating hours and should not be used in your EGU's compliance determination calculations [§60.5555a(c)(4)].

Additionally, there are specific requirements concerning the person who can submit these reports. If your affected EGU is subject to the Acid Rain Program, this person is the Designated Representative (DR) appointed under 40 CFR 72.20 but can also be the Alternate Designated Representative (ADR) appointed under 40 CFR 72.22 or someone authorized by the DR or ADR [§60.5555a(d)(1)-(3)]. If your affected EGU is not subject to the Acid Rain Program, you must appoint a DR and may also appoint an ADR who can submit these reports after they register with the Clean Air Markets Divison Business System [§60.5555a(e)].

6.3 What reporting is required related to CCS?

If your affected EGU captures CO_2 to meet its applicable emission standard, there are specific reporting requirements that you must meet, additional requirements that also apply to you if you inject your CO_2 on-site, and other requirements that apply to facilities to which you transfer your CO_2 if you do not inject it on-site.

6.3.1 What applies to all affected EGUs that capture CO_2 to meet their emission standard?

First, regardless of the captured CO_2's final destination, you must report according to the requirements of 40 CFR part 98, subpart PP [§60.5555a(f)].

Subpart PP requires that you report the mass of CO_2 captured from the relevant process and other amounts of CO_2 captured, produced, and imported and exported, as applicable. In addition to the CO_2 mass, you must report other information, including the percentage of the total annual mass that is biomass-based, if any, and annual amounts of CO_2 transferred to a given list of end-use applications, which includes enhanced oil and natural gas recovery and long-term storage.

The full text of 40 CFR part 98, subpart PP can be accessed here: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-PP.

6.3.2 What additional reporting requirements apply if you inject your captured CO_2 on-site?

If the captured CO_2 is injected on-site, you must also report depending on how the CO_2 is used:

1. If the CO_2 will be injected for long-term containment in subsurface geologic formations, you must report according to 40 CFR part 98, subpart RR; or
2. if the CO_2 will be injected as part of enhanced oil recovery, you must report according to subpart VV [§60.5555a(f)(1)].

Subpart RR requires that you report the mass of CO_2 that you receive to inject and the actual amount sequestered, as well as creating plans for monitoring, reporting, and verification.

The full text for 40 CFR part 98, subpart RR can be accessed here: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR.

Subpart VV requires that you report information about your enhanced oil recovery (EOR) system including information about the wells used for storage with sufficient information to demonstrate that the EOR complex is adequate to provide safe, long-term containment of CO_2.

6.3.3 What reporting requirements apply to the facilities to which you transfer your captured CO_2 if you do not inject it on-site?

If you do not inject the captured CO_2 on-site, you must transfer it to a facility that reports in accordance with 40 CFR part 98, subpart RR, or subpart VV [§60.5555a(f)(2)]; or transfer it to a facility that has received an innovative technology waiver from the EPA for the way in which they intend to store the CO_2 [§60.5555a(f)(3)].

6.4 What records must I maintain?

6.4.1 General recordkeeping requirements

A variety of records must be maintained due to this rule, some of which depend on other regulations, as well as others specific to this rule itself. Records must be:

- In a form suitable and readily available for expeditious review;
- Maintained for 5 years after the date of conclusion of each compliance period; and
- Maintained on site for at least 2 years (records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement) [§60.5565a].

6.4.2 Records required from §60.7 (b) and (f)

You must maintain records used to determine compliance with this rule as specified in §60.7(b) and (f) [§60.5560a(a)].

Section 60.7(b) requires that you maintain records of:

- The occurrence and duration of an affected EGU's startup, shutdown, or malfunction;
- Any malfunction of air pollution control equipment; or
- Any periods during which a continuous monitoring system or monitoring device is inoperative.

Section 60.7(f) requires that you maintain records of all measurements in a permanent form suitable for inspection for at least two years following the date of the measurements, maintenance, reports, and records. These measurements include:

- Continuous monitoring system, monitoring device, and performance testing measurements;
- All continuous monitoring system performance evaluations;
- All continuous monitoring system or monitoring device calibration checks;
- Adjustments and maintenance performed on these systems or devices; and
- All other information required by part 60.

There are, however, exceptions to the measurements and requirements listed in §60.7(f). These include:

- If you are required to install a CEMS, the CEMS is automated, and the calculated averages do not exclude periods of CEMS breakdown or malfunction; you must keep the most recent consecutive three averaging periods of sub-hourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.
- If you are required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard and the calculated data averages do not exclude periods of breakdown or malfunction, you must retain all sub-hourly measurements for the most recent reporting period. These sub-hourly measurements must be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.
- Regardless of other exceptions, the Administrator or a delegated authority may require you to maintain all measurements required by paragraph (f) if they determine the records are required to more accurately assess your EGU's compliance.

6.4.3 Records related to the Acid Rain Program

If your affected EGU is subject to the Acid Rain Program, you must follow the applicable reporting requirements and maintain records as required in part 75 subpart F.

If your affected EGU is not subject to the Acid Rain Program, you must also follow the applicable reporting requirements and maintain records as required in part 75 subpart F. At a minimum, this includes:

- Monitoring plan records [§60.5560a(b)(2)(i)]
- Operating parameter records [§60.5560a(b)(2)(ii)]
- Stack gas volumetric flow rate records [§60.5560a(b)(2)(iii)]
- Continuous moisture monitoring system records [§60.5560a(b)(2)(iv)]
- CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration records [§60.5560a(b)(2)(v)]
- Oil flow meter records [§60.5560a(b)(2)(vi)]
- Gas flow meter records [§60.5560a(b)(2)(vii)]
- Quality-assurance records for CEMS [§60.5560a(b)(2)(viii)]
- Quality-assurance records for fuel flow meters [§60.5560a(b)(ix)]
- Data acquisition and handling system verification records [§60.5560a(b)(x)]

6.4.4 Records related to your EGU's emission and compliance calculations

Additionally, you must keep records used to perform calculations to determine your affected EGU's hourly and total CO_2 mass emissions for each operating month and each compliance period [§60.5560a(c)(1) and (2)].

You must also keep these records:

- Relevant data and calculations used to determine your affected EGU's monthly gross or net energy output [§60.5560a(d)]
- Calculations performed to determine the percentage of valid CO_2 mass emission rates in each compliance period [§60.5560a(e)]
- Calculations to assess compliance with the applicable emission standard [§60.5560a(f)]
- Calculations to determine any site-specific carbon-based F-factors used in the emission calculations, if applicable [§60.5560a(g)]

For stationary combustion turbines, you must keep records of the electric sales used to determine the applicable subcategory [§60.5560a(h)].

6.4.5 Records related to operating during a documented system emergency

There are also specific records that you must keep to demonstrate that your affected EGU operated during a system emergency:

- Documentation from the entity issuing that a system emergency was in effect, including the exact duration of the event [§60.5560a(i)(1)]
- Documentation that the system emergency included the area in which your affected EGU is located [§60.5560a(i)(2)]
- Documentation that your affected EGU was instructed to increase output beyond the planned day-ahead or near-term expected output and/or remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization [§60.5560a(i)(3)]

Section 7. Other Requirements and Information

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

Parts of the General Provisions that apply to your affected EGU

- §60.1: Applicability
- §60.2: Definitions
- §60.3: Units and Abbreviations
- §60.4: Address
- §60.5: Determination of construction or modification
- §60.6: Review of plans
- §60.7 Notification and Recordkeeping
- §60.8(b) Performance test method alternatives
- §60.9: Availability of Information
- §60.10: State Authority
- §60.12: Circumvention
- §60.13(i): Monitoring requirements
- §60.14: Modification (for steam generating units and IGCC)
- §60.15: Reconstruction
- §60.17: Incorporation by reference
- §60.19: General notification and reporting requirements

Parts of the General Provisions that do not apply to your affected EGU

- §60.8(a): Performance tests
- §60.8(c)-(f): Conducting performance tests
- §60.11: Compliance with standards and maintenance requirements
- §60.13(a)-(h), (j): Monitoring requirements
- §60.14: Modification (for stationary combustion turbines)
- §60.16: Priority list
- §60.18: General control device requirements

Figure 8. Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa.

7.2 Who implements and enforces this rule?

This rule can be implemented and enforced by the EPA or a delegated authority such as your state, local, or Tribal agency. If the Administrator delegates authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this rule. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency. [§60.5575a(a)].

Regardless of any delegation, there are some authorities that the Administrator retains which are not transferred to other entities:

- Approval of alternatives to the emission standards
- Approval of major alternatives to test methods
- Approval of major alternatives to monitoring
- Approval of major alternatives to recordkeeping and reporting
- Performance test and data reduction waivers under §60.8(b) [§60.5575a(b)]

The EPA also retains oversight of this subpart and can take enforcement actions, as appropriate.