UNITED STATES AIR FORCE

GUIDE TO THE MANDATORY GREENHOUSE GAS REPORTING RULE AND GREENHOUSE GAS TAILORING RULE

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EXECUTIVE SUMMARY

The regulation of Greenhouse Gas (GHGs) is a relatively new aspect of air quality. In 2009, the United States Environmental Protection Agency (EPA) concluded, after a thorough review of scientific evidence, that GHG threatens the public health and welfare; this is known as the "endangerment finding". The finding laid down the foundation for GHG related rules, including the two rules discussed in this Guide in three sections:

- Section One, Introduction, discusses the history and regulatory background for GHG and the rules covered in this Guide.
- Section Two, Mandatory GHG Reporting Rule (MRR), includes the requirements for tracking and reporting GHG emissions for facilities that emit over a certain threshold (40 CFR 98).
- Section Three, GHG Tailoring Rule, discusses GHG applicability and requirements that pertain to two major stationary source permits; Prevention of Significant Deterioration (PSD) is a preconstruction permit (40 CFR 51.166 and 52.21), which is frequently followed by a Title V Operating Permit (40 CFR Parts 70 and 71).

Section One, Introduction - The intent of this guidance is to assist interested Unites States Air Force (USAF) personnel with understanding the requirements of those rules. This document is intended for guidance only and may be impacted by changes in legislation, rules, policies, and procedures adopted after the date of publication. Additionally, this guidance does not change any law, regulation, or other legally binding requirement.

Pollutants Regulated: GHG is a single pollutant consisting of an aggregate of the following six well-mixed gases, measured in carbon dioxide equivalents (CO_2e): Carbon dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O), Sulfur hexafluoride (SF_6), Hydrofluorocarbons (HFC), and Perfluorocarbons (PFC).

Each GHG has a different Global Warming Potential (GWP) and persists for a different length of time in the atmosphere; therefore, GHG emissions are converted into CO_2 equivalents (CO_2e) so they can be compared. The intent is to measure the impact of each GHG component in terms of the amount of CO_2 that would create the same amount of warming. For example, one ton of methane would be equal to 25 tons of CO_2e, because it has a GWP 25 times that of CO_2.

Section Two, Mandatory Greenhouse Gas Reporting Rule (MRR) - The MRR is an EPA-led endeavor to track and gather GHG emissions data from large emitters. The objective is to determine which GHGs are being emitted, how much of those GHGs are being emitted, and from which industry sectors those GHGs are being emitted. A facility subject to the MRR is considered compliant by submitting an annual GHG report to the EPA.

MRR Facility: Generally, a facility is property under common control and has a contiguous boundary. Due to the variety of functions and control arrangements performed at military installations, they are complex in nature and can be separated into more than a single facility based on distinct and independent functional groupings within contiguous military properties. For example, personnel-related activities, such as residential housing and shopping centers at military installations, can be considered separate sources from military activities (e.g., ammunitions training range). A military installation may also be classified as more than one facility for equipment that is owned and operated by separate branches of service. For instance, pollutant-emitting activities at an installation owned and operated by the USAF are separate from those owned or operated by the Army, Navy, or Marine Corps.

Source Categories: The EPA compiled source categories that may be subject to MRR reporting. If no source category is present, the facility is not subject to the MRR. The only source category that triggers reporting for military facilities is 40 CFR 98 Subpart C, *General Stationary Fuel Combustion Sources*. Figure E-1, *Is the MRR Applicable to My Base?*, illustrates applicability for the United States Air Force (USAF).

Reporting: An annual emissions report must be generated and submitted to the EPA via the electronic Greenhouse Gas Reporting Tool (e-GGRT). Users register the facility in e-GGRT and input data to quantify emissions. Each source category has specific calculations used when generating these annual reports. Reports are due by March 31 and reflect the previous year's annual emissions. The MRR allows for cessation of reporting when emissions fall below 25,000 metric tons of CO_2e for five consecutive years or 15,000 metric tons of CO_2e for three consecutive years.

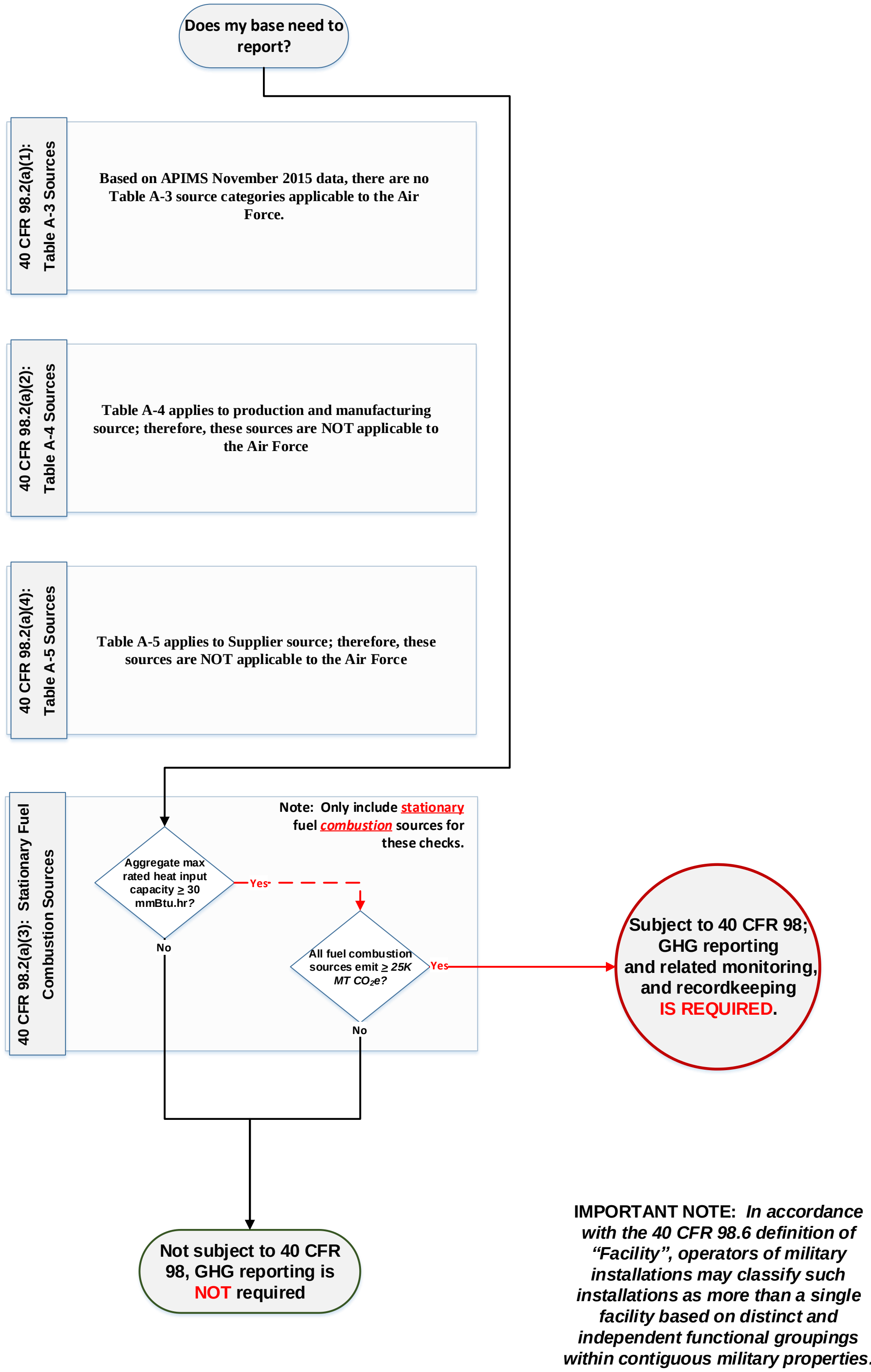

Figure E-1 Is the MRR Applicable to My Base?

Section Three, PSD and Title V Permit Tailoring Rule – The EPA promulgated rules to "tailor" GHG applicability for two Clean Air Act (CAA) major stationary source permitting programs, PSD (preconstruction) and Title V (operating). This action avoided impacting millions of small sources of GHG emissions and prevented a permit gridlock for regulatory agencies. The CAA's thresholds of 100 or 250 tons per year are appropriate for conventional pollutants, according to the EPA, but they are not reasonable for GHGs, which are emitted in significantly larger quantities. Accordingly, on 13 May 2010, based on the legal doctrines of ''absurd results'' and ''administrative necessity'', EPA raised the GHG applicability thresholds to a more practical level of 75,000 CO_2e tons per year. The Tailoring Rule was challenged and the United States Supreme Court held that only sources already subject to PSD and Title V for another pollutant will need to address GHG emissions. EPA refers to these sources as "anyway" sources, because they will have to go through permitting "anyway" for another pollutant. On 3 October 2016, the EPA proposed revisions to the Tailoring Rule to bring the rule in line with the Court's decision, but the rule has not been finalized as of May 2017.

Applicability: Per the EPA's July 2014 document, *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*, the following applicability thresholds will apply until further guidance or a final rule is published with different instructions:

- New "anyway sources": PSD Best Available Control Technology (BACT) will apply for GHG if the source emits or has the potential to emit 75,000 CO_2e tons per year or more of GHG.
- Existing "anyway sources" that are modified: PSD BACT will apply if <u>both</u> circumstances are present:
  - The modification is otherwise subject to PSD for a pollutant other than GHG.
  - The modification results in both a net GHG emissions increase equal to or greater than 75,000 CO_2e tons per year and greater than zero on a mass basis.
- For Title V, sources will be required to incorporate GHG emission requirements in new Title V permit applications and in any renewals or revisions to existing Title V permits.

Requirements: In multiple guidance and discussions within the preamble to the final and proposed rules, EPA emphasizes the importance of GHG BACT that improves energy efficiency. Permitting authorities are to continue using the EPA's long standing BACT five-step process in determining the best control methods for GHG on a case-by-case basis: 1) identify all available control technologies, 2) eliminate technically infeasible options, 3) evaluate and rank remaining control technologies based on environmental effectiveness, 4) evaluate cost effectiveness of controls and energy and other environmental impacts, and 5) select the BACT.

1 SECTION ONE: GUIDE INTRODUCTION

1.1 Purpose

The United States Air Force (USAF) developed this guide as a tool to assist interested USAF parties in navigating through the complexities of the Greenhouse Gas (GHG) Mandatory Reporting Rule (MRR) and the GHG Tailoring Rule. This document describes, in general terms, the requirements of the MRR and the application of the Tailoring Rule as it pertains to GHGs [New Source Review (NSR) and Title V permitting requirements for GHGs]. The information within this Guide will be useful to people responsible for complying with the rule(s) and others who want a general understanding of the concepts.

This guidance, although comprehensive, is intended to clarify and provide a general overview of the regulations. This Guide does not replace any law, regulation, or other legally binding requirement and is not legally enforceable. Also, the guidance this document contains may not be appropriate for all situations (EPA may use their discretion to approach issues differently, depending on situations that may arise). The rules themselves, as well as any associated Environmental Protection Agency (EPA), Department of Defense (DoD), or USAF guidance documents need to be carefully read to gain a complete understanding of the requirements. Should there be any inconsistency between this guidance and the rules, the rules govern.

The information conveyed in this Guide is dynamic and subject to change depending on rules promulgated by the EPA. EPAs regulation of GHGs has been the subject of numerous judicial challenges and GHG regulation in the United States is precarious; therefore, regulatory requirements may be issued, vacated, or revised after publication of this document. The Code of Federal Regulations (CFR), electronic CFR (e-CFR), and the Federal Register (FR) should be consulted for updates as this Guide is based on the April 2017 CFR. Citations are used throughout this guide to refer the reader to the appropriate regulatory sections for more information.

The use of non-mandatory language such as “guidance,” “recommend,” “may,” “should,” and “can,” is intended to describe policies and recommendations. Terminology such as “must” and “required” are intended to describe mandatory requirements under the terms of the Clean Air Act (CAA) and EPA regulations, but this document does not establish legally binding requirements in and of itself.

This Guide is organized into three primary sections:

- Section One, Guide Introduction, explains the purpose of this Guide and provides a general background on GHG regulations.

- Section Two, Mandatory Greenhouse Gas Reporting Rule, explains the applicability criteria and requirements necessary for complying with the MRR. The MRR, codified at 40 CFR Part 98, requires certain facilities to report annual emissions of GHGs. Facilities that are subject to the MRR must comply with requirements for data monitoring, quality assurance, recordkeeping, emissions calculation methodologies, and reporting.

- Section Three, Greenhouse Gas Tailoring Rule, provides general information for how GHG is handled during the permitting process, including applicability criteria and the permitting of major stationary sources for GHG. Permitting requirements for GHGs only apply to sources that must obtain an air permit “anyway” based on emissions of other pollutants. EPA regulates “anyway” sources of GHG emissions if those emissions exceed applicability thresholds (de minimis levels).

Any questions concerning this document, and/or requests for additional information pertaining to MRR, should be directed to the Air Quality Subject Matter Expert; AFCEC Compliance Technical Support Branch (AFCEC/CZTQ); 250 Goodrich Drive; Building #1650, San Antonio, TX 78226.

1.2 Background

GHGs are responsible for regulating Earth’s temperature through a greenhouse effect (Earth's atmosphere traps some of the energy from the sun). Incoming solar radiation (heat) from the sun enters and passes through Earth’s atmosphere. Though some of this radiation is reflected back into space via clouds and small particles, much of it is absorbed by Earth, where it warms the surface of the planet. The energy radiating from Earth's surface is then absorbed by atmospheric GHGs and re-emitted in all directions. The energy that radiates back down to Earth heats both the lower atmosphere and the surface. Figure 1-1, *Simple Illustration of Global Warming*, illustrates the concept of global warming.

Without the greenhouse effect, Earth would be too cold to sustain life; however, an overabundance of GHGs in the atmosphere may be causing an enhanced greenhouse effect resulting an in abnormal rise in Earth’s surface temperature. Earth’s climate has constantly shifted over geological time, but this rise in temperature is thought to be altering and/or accelerating the natural process (climate change). The term “climate change” refers to significant measurable change in climate (such as temperature or precipitation) over an extended period (decades or longer). Climate change is recognized to be responsible for an increase in recent extreme weather events such as damaging droughts and large storms. The source of GHGs can be anthropogenic (resulting from human activities such as industry and driving cars) or natural (such as volcanic activity and wildfires). Reducing anthropogenic GHG in the atmosphere may normalize the rate of change in Earth’s climate.

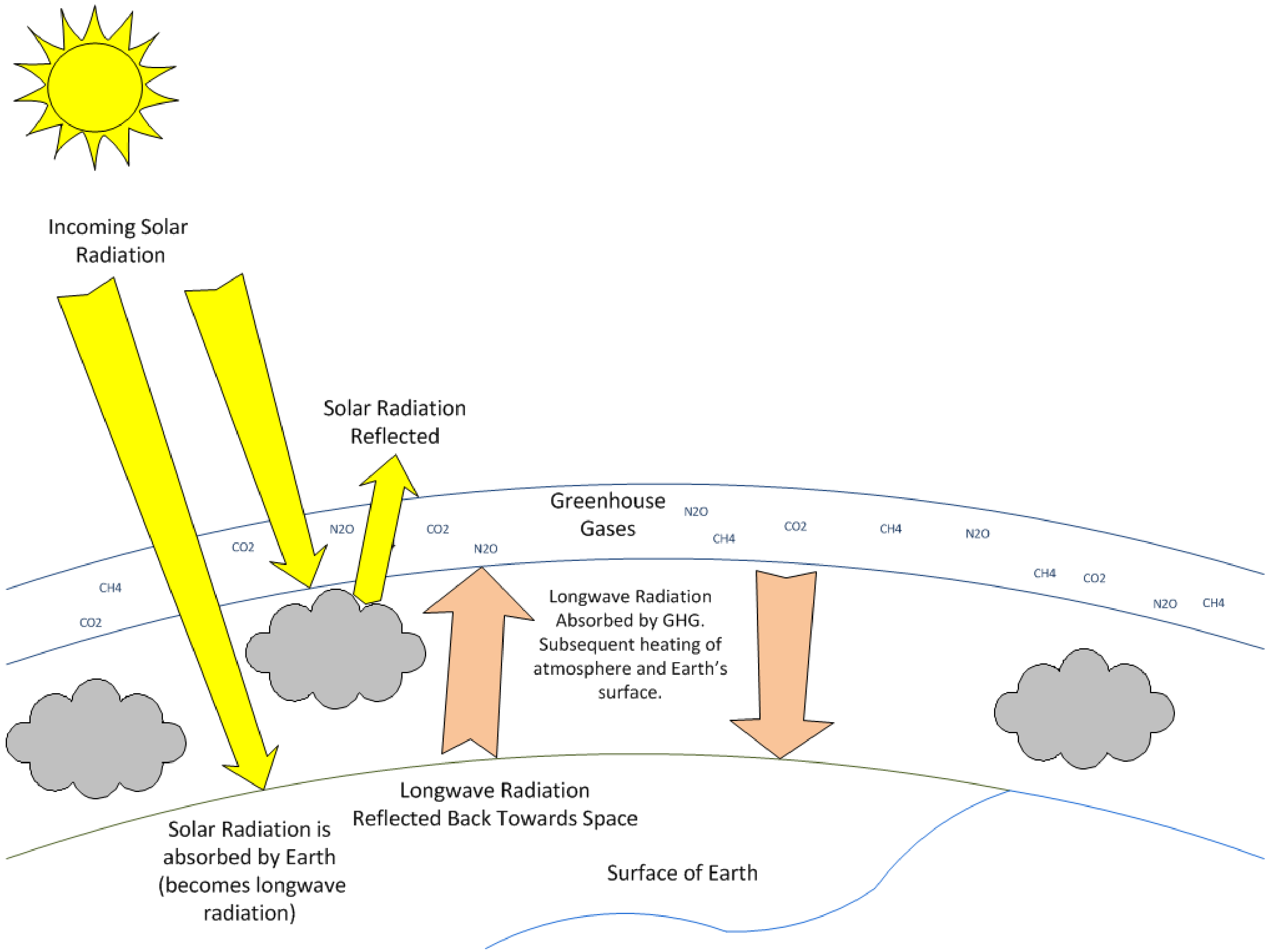

Figure 1-1 Simple Illustration of Global Warming

1.3 Regulatory Context

The EPA's authority to regulate GHG through the CAA came from the United States Supreme Court's determination in Massachusetts v. EPA (2007) that GHG emissions would meet the definition of "air pollutants" if EPA formed a judgment, based on scientific evidence, proving GHG emissions endanger public health or welfare. This court ruling led to an extensive review of scientific evidence. On 15 December 2009 (74 FR 66496), EPA found that elevated atmospheric concentrations of GHG endanger both public health and welfare ("the endangerment finding"). GHG is a single pollutant consisting of an aggregate of the following six well-mixed gases:

- Carbon dioxide (CO_2),
- Methane (CH_4),
- Nitrous oxide (N_2O),
- Sulfur hexafluoride (SF_6),
- Hydrofluorocarbons (HFC), and
- Perfluorocarbons (PFC).

The EPA's endangerment finding did not impose any requirements to control GHG emissions, but the findings were a prerequisite to promulgating GHG standards. Essentially, the endangerment finding put GHGs on the regulatory radar; over 100 GHG related regulations have been proposed or finalized by the EPA since 2009, including the MRR and the Tailoring Rule. However, the MRR is solely a reporting mechanism for tracking actual GHG emissions while the Tailoring Rule is regulatory in nature and uses the facility's potential-to-emit (PTE) GHG emissions to determine PSD and Title V permitting program applicability. Therefore, it is imperative that the MRR and Tailoring Rule are treated distinctly and separately.

1.3.1 Mandatory Reporting Rule Legal Background

In response to the Endangerment Finding, the EPA announced in September 2009 that it will require large emitters of GHGs to begin collecting and reporting data. Previously, the EPA did not have a comprehensive method for tracking GHG emissions data that was connected to a specific facility or to an industrial category. The information derived from the data is intended to help guide future EPA policy. Motor vehicle and engine manufacturers, industry GHG and fossil fuel suppliers, and facilities that emit 25,000 metric tons or more of CO_2e per year are required to monitor GHG emissions and report the data to EPA annually beginning in January 2010.

A Final rule published on 9 December 2016 (81 FR 89188) revised provisions in 29 subparts of the MRR to streamline and improve implementation of the rule and enhance data quality.

Implementation will be phased in over three years; 1 January 2017 through 1 January 2019 (effective dates specified in the FR notice). Other items in the final rule are intended to:

- Better reflect industry processes and emissions.
- Clarify and correct portions of the rule to improve understanding.
- Clarify opportunities to stop reporting.
- Clarify the need to resubmit a report in which there were substantive errors only within the time-period required to maintain records (three or five years depending on whether facility uses the Inputs Verification Tool).

1.3.2 Tailoring Rule Legal Background

The purpose of the Tailoring Rule is to customize, or "tailor", GHG thresholds to limit the number and size of sources subject to PSD and Title V permitting requirements. Regulating GHG sources at the usual statutory thresholds of 100 or 250 tons per year (tpy) would impact millions of sources, including small GHG emitters such as schools and shopping malls, creating an unmanageable situation for sources and permitting authorities. Thus, the Tailoring Rule did not include sources emitting less than 75,000 tpy CO_2e of GHGs. Sources that emitted GHG beyond those thresholds were required to obtain permits, either from the EPA or from the state if the state had permit-writing authority. Accordingly, on 3 June 2010, the EPA issued the final "*Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*" (GHG Tailoring Rule) which phased in permitting requirements for GHG emissions from stationary sources under the PSD and Title V permitting programs through steps (75 FR 31514):

- Step 1 of the Tailoring Rule, which began on 2 January 2011, PSD or Title V requirements applied to sources' GHG emissions only if the sources were subject to PSD or Title V ''anyway'' due to their emissions of non-GHG pollutants. These sources are referred to as ''anyway sources''.

- Step 2 of the Tailoring Rule, which began on 1 July 201, extended PSD and Title V requirements to additional sources based solely on GHG emissions if those emissions exceeded the regulatory thresholds. The Step 2 permitting regulations were ruled to be invalid by the United States Supreme Court.

- Step 3 of the Tailoring Rule, issued on 29 June 2012, retained the GHG thresholds and provisions of Step 1 and Step 2. EPA reevaluated the limits imposed by the original regulation and determined no benefit would be gained by lowering the GHG thresholds. The rule also improved GHG Plantwide Applicability Limitations (PALs) by allowing GHG PALs to be established on a carbon dioxide equivalent (CO_2e) basis (PAL is a facility-wide permit limit for a pollutant).

- Step 4 of the Tailoring Rule was to include possible further phasing-in of lower GHG emissions thresholds depending on the results of an EPA study; however, the EPA does not intend to take further action on Step 4 at this time.

1.3.2.1 Tailoring Rule Litigation

The Tailoring Rule faced both legal and political challenges and quickly became a source of contentious litigation. As a result, two major court judgments significantly impacted the Tailoring Rule:

- On 23 June 2014, the U.S. Supreme Court issued a decision in *Utility Air Regulatory Group (UARG) v. EPA* (Case No. 12-1146) that the EPA may:
  - Not treat GHGs as an air pollutant for determining whether a source is required to obtain a PSD or Title V permit.
  - Continue to require sources that require a PSD or Title V permit based on emissions of non-GHG pollutants ("anyway sources") to conduct a Best Available Control Technology (BACT) analysis for GHGs; essentially vacating Step 2 of the Tailoring Rule and reverting to Step 1.
  - Limit PSD BACT review to those situations where a source actually emits or has the potential-to-emit (PTE) GHGs above a threshold (or de minimis level).

- On 10 April 2015, the D.C. Circuit Court in the case, *Coalition for Responsible Regulation v. EPA*, issued an amended judgment that:
  - Identified and clarified the specific permitting regulations that were vacated by *UARG v EPA.*
  - Ordered EPA to rescind and/or revise the vacated provisions "as expeditiously as practicable" and consider whether further revisions are appropriate. The EPA was not given a deadline or timeline to accomplish this task.

In response to these Court Judgments, the EPA acted quickly to rescind portions of the PSD and Title V permits that were not required to undergo the required rulemaking process (proposed rule notice and public/stakeholder comment period). This action is limited to situations where there is "good cause" to forgo the notice and comment period or the action is routine or uncontroversial.

- In April 2015, the EPA issued a direct final rule revising the EPA's PSD regulations to provide a vehicle for the EPA and delegated permitting authorities to rescind Step 2 related State Implementation Plan (SIP) requirements that were contrary to the Court's ruling (80 FR 26183 and 80 FR 26210).

- In August 2015, the EPA issued a good cause final rule that amended the PSD and Title V regulations to remove those vacated provisions that could be removed from the regulations through a ministerial action (performed according to instructions from a superior authority). The removed regulations included the portions of Step 2 of the Tailoring Rule as applicable to the PSD and Title V regulations that required EPA to consider further phasing-in additional steps to lower GHG emission thresholds (80 FR 50199).

1.3.2.2 Pending Revisions

On 3 October 2016, the EPA published proposed revisions to bring the EPA's air permitting regulations in line with the Court's decisions on GHG permitting (81 FR 68110). This rulemaking proposes:

- Revisions to the PSD and Title V regulations to ensure that neither the PSD nor Title V rules require a source to obtain a permit solely because the source emits or has the potential to emit GHGs above the applicable thresholds.

- To include a 75,000 tpy CO_2e Significant Emission Rate (SER) for GHGs. The SER will establish a de minimis level for GHGs below which BACT is not required for "anyway sources."

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2 SECTION TWO: MANDATORY GREENHOUSE GAS REPORTING RULE

2.1 Introduction

NOTE: On 9 December 2016, the EPA finalized amendments to the MRR. Most of those amendments will not come into effect until 1 January 2018 and may be applicable to the 2017 reporting year. A separate subsection was created in this chapter outlining the changes that may be relevant to USAF installations.

In October of 2009, the EPA published the MRR requiring annual reporting of GHG data from a wide range of sectors (74 FR 56260). This rule applies to fossil fuel suppliers and industrial gas suppliers, direct GHG emitters, and manufacturers of heavy-duty/off-road vehicles and engines.

GHGs are assigned a Global Warming Potential (GWP), which is a measure of how much heat the gas traps in the atmosphere calculated over a specific time interval, typically 100 years. The higher the GWP, the greater the potential for the gas to trap heat, and the more harmful the gas is regarded. CO_2 is used as the baseline gas and assigned a GWP of 1. Emissions of GHGs may be converted into equivalent CO_2 (CO_2e) by taking the product of each GHG emission factor and its respective GWP. The total GHG emissions are calculated by summing all emissions from each gas.

The GHGs subject to the MRR include carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, perfluorocarbons and other fluorinated gases

- **Carbon Dioxide (CO_2):** CO_2 enters the atmosphere via the combustion of fossil fuels (oil, natural gas, and coal), solid waste, trees and wood products, and as a result of other chemical reactions. CO_2 is also removed from the atmosphere (or "sequestered") when it is absorbed by plants as part of the biological carbon cycle.

- **Methane (CH_4):** CH_4 is emitted during the production and transport of coal, natural gas, and oil. Methane emissions also result from livestock and other agricultural practices, as well as by the decay of organic waste in municipal solid waste (MSW) landfills.

- **Nitrous Oxide (N_2O):** N_2O is emitted during agricultural and industrial activities, as well as during the combustion of fossil fuels and solid waste.

- **Fluorinated Gases:** Hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride (SF_6) are powerful synthetic GHGs that are emitted from a variety of industrial processes. These gases are usually emitted in smaller quantities, but they are potent GHGs with high GWPs.

A facility subject to the MRR needs to ensure data integrity. To provide such data, take measures to accurately and consistently quantify emission data for compliance and provide the EPA with reliable data to guide future GHG policy. The compiled data will assist the EPA in addressing GHG emissions and climate change and improve the government's ability to create climate policies (74 FR 56260).

Sections 114 and 208 of the Clean Air Act give the EPA the authority to require the information requested by the EPA because it enables the EPA to perform a variety of Clean Air Act provisions. This ruling is also consistent with the Congressional request within the FY2008 Consolidated Appropriations Act.

2.2 State Greenhouse Gas Requirements

Some states, such as California, Florida, New York, and New Mexico, have their own additional requirements for reporting GHG emissions. The MRR is a separate GHG reporting requirement and submission of emissions reports to the state does not exclude an entity subject to MRR from MRR reporting to the EPA. Furthermore, the submission of an MRR report to the EPA does not exempt an entity from submitting separate reports that satisfy state GHG reporting requirements.

2.3 Who is subject to the MRR?

Owners and operators of certain facilities that directly emit GHGs, as well as certain suppliers, are subject to the MRR. For military purposes, the owner of the facility is the federal government (which is managed by the Bureau of Land Management) and the operator is the military entity (i.e., the specific installation) responsible for operations at the facility. The operator is the entity responsible for MRR compliance. The MRR applies only to USAF installations that meet the threshold requirements listed in 40 CFR 98, Subpart A. Applicability provisions for direct emitters of GHGs are summarized in tables referred to in 40 CFR 98.2(a)(1), (2), and (3). These tables are presented here as Table 2-1, *Source Categories and USAF Applicability*, Table 2-2, *Source Category List*, and Table 2-3, *Source Categories (Suppliers)*.

The owners or operators of any facility located in the United States, U.S. territories, or under/attached to the Outer Continental Shelf (as defined in 43 U.S.C. 1331) that meet any of the following conditions must report under the MRR:

- **Source Automatically Subject to Reporting:** A facility that contains any source category listed in Table 2-1, *Source Categories and USAF Applicability*, in any calendar year beginning in 2010 is automatically subject to reporting. For these facilities, the annual GHG report must cover stationary fuel combustion sources and all other applicable source categories. Most of the source categories listed in Table 2-1 relate strictly to production; therefore, they are not applicable to the Air Force. However, **there are two source categories [Municipal Solid Waste (MSW) landfills and electrical**

transmission/distribution equipment] that may have potentially applied to Air Force facilities. ***However, based on November 2015 APIMS data, NO Air Force facilities are subject to reporting under MSW Landfills (40 CFR 98 Subpart HH) or Electrical Transmission and Distribution Equipment Use (40 CFR 98 Subpart DD) source categories.***

- **Production and Manufacturing Sources:** A facility that has any source category listed in Table 2-2 and emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories that are listed in Table 2-1 and Table 2-2 are subject to MRR. The Air Force is not a production or manufacturing entity; therefore, **these source categories are not applicable to the Air Force.**

- **Supply Sources:** Suppliers listed in Table 2-3, *Source Categories (Suppliers)*, are also subject to the reporting requirements and related monitoring, and recordkeeping of the MRR. The Air Force is not a commercial entity and is not in the supply business; therefore, Table 2-3 **source categories are not applicable to the USAF.**

- **Stationary Fuel Combustion Sources:** This is an additional source category in 40 CFR 98. For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources **only**. A facility that, in any calendar year starting in 2010, meets all three of the following listed conditions is subject to the MRR:
    - The facility is not a source automatically subject to reporting.
    - The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is **30 Million British Thermal Units per hour (MMBtu/hr) or greater**.
    - The facility emits **25,000 metric tons CO_2e or more per year** in combined emissions from all stationary fuel combustion sources.

Note that the Stationary Fuel Combustion Unit Source Category is the only source category that may trigger the MRR at USAF facilities.

It is important to note that research and development activities are not considered part of ANY source category subject to the Rule [40 CFR 98.2(a)(5)]. Research and development includes those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and development for new processes, technologies, or products and whose purpose is not for the manufacture of products for commercial sale, except in a de minimis manner [40 CFR §98.6].

The following sources should not be included in any USAF facility's annual GHG MRR report:

- Industrial Wastewater Treatment Systems (Does not apply to any USAF systems)
- Industrial Waste Landfills (Does not apply to any USAF landfills.

Table 2-1 Source Categories and USAF Applicability

Source Category	Applicable to USAF
Source Categories Applicable in 2010 and Future Years:	
Electricity generation units that report CO_2 mass emissions year-round through 40 CFR part 75 (subpart D)	NA, power sector
Adipic acid production (subpart E)	NA, production sector
Aluminum production (subpart F)	NA, production sector
Ammonia manufacturing (subpart G)	NA, production sector
Cement production (subpart H)	NA, production sector
HCFC-22 production (subpart O)	NA, production sector
HFC-23 destruction processes that are not collocated with HCFC-22 production facility and that destroy more than 2.14 metric tons of HFC-23 per year (subpart O)	NA, production sector
Lime manufacturing (subpart S)	NA, production sector
Nitric acid production (subpart V)	NA, production sector
Petrochemical production (subpart X)	NA, production sector
Petroleum refineries (subpart Y)	NA, production sector
Phosphoric acid production (subpart Z)	NA, production sector
Silicon carbide production (subpart BB)	NA, production sector
Soda ash production (subpart CC)	NA, production sector
Titanium dioxide production (subpart EE)	NA, production sector
Municipal solid waste landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year (subpart HH)	NA, at this time, No USAF installation generates CH_4 in amounts equal to 25,000 metric tons or more CO_2e per year
Manure management systems with combined CH_4 and N_2O emissions in amounts equivalent to 25,000 metric tons CO_2e or more per year (subpart JJ)	NA
Additional Source Categories Applicable in 2011 and Future Years	
Electrical transmission and distribution equipment use at facilities where the total nameplate capacity of SF_6 and PFC containing equipment exceeds 17,820 pounds (subpart DD)	NA, at this time, No USAF installation has SF_6 and PFC containing equipment that exceeds total nameplate capacity of 17,820 pounds
Underground coal mines liberating 36,5000,000 actual cubic feet of CH_4 or more per year (subpart FF)	NA
Geologic sequestration of carbon dioxide (subpart RR)	NA
Electrical transmission and distribution equipment manufacture or refurbishment (subpart SS)	NA
Injection of carbon dioxide (subpart UU)	NA

SOURCE 40 CFR 98 Table A-3 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.

Table 2-2 Source Category List

Source Category	Applicable to USAF
Source Categories Applicable in 2010 and Future Years:	
Ferroalloy production (subpart K).	NA, production sector
Glass production (subpart N).	NA, production sector
Hydrogen production (subpart P).	NA, production sector
Iron and steel production (subpart Q).	NA, production sector
Lead production (subpart R).	NA, production sector
Pulp and paper manufacturing (subpart AA).	NA, production sector
Zinc production (subpart GG).	NA, production sector
Additional Source Categories Applicable in 2011 and Future Years	
Electronics manufacturing (subpart I)	NA, production sector
Fluorinated gas production (subpart L)	NA, production sector
Magnesium production (subpart T).	NA, production sector
Petroleum and Natural Gas Systems (subpart W)	NA
Industrial wastewater treatment (subpart II).	NA
Industrial waste landfills (subpart TT).	NA

SOURCE 40 CFR 98 Table A-4 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.

Table 2-3 Source Categories (Suppliers)

Source Categories	Applicability to USAF
Supplier Categories Applicable in 2010 and Future Years	
Coal-to-liquids suppliers (subpart LL):	NA; This applies to suppliers
(A) All producers of coal-to-liquid products.	
(B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO_2e or more.	
(C) Exporters of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO_2e or more.	
Petroleum product suppliers (subpart MM):	NA; This applies to suppliers
(A) All petroleum refineries that distill crude oil.	
(B) Importers of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO_2e or more.	
(C) Exporters of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO_2e or more.	
Natural gas and natural gas liquids suppliers (subpart NN):	NA; This applies to suppliers
(A) All fractionators.	
(B) Local natural gas distribution companies that deliver 460,000 thousand standard cubic feet or more of natural gas per year.	
Industrial greenhouse gas suppliers (subpart OO):	NA; This applies to suppliers
(A) All producers of industrial greenhouse gases.	
(B) Importers of industrial greenhouse gases with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.	
(C) Exporters of industrial greenhouse gases with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.	
Carbon dioxide suppliers (subpart PP):	NA; This applies to suppliers
(A) All producers of CO_2.	
(B) Importers of CO_2 with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.	
(C) Exporters of CO_2 with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.	
Additional Supplier Categories Applicable in 2011 and Future Years	
Importers and exporters of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams (subpart QQ):	NA; This applies to importers and exporters
(A) Importers of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO_2e or more.	
(B) Exporters of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO_2e or more.	

SOURCE 40 CFR 98 Table A-5 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.

2.4 MRR Applicability to Military Installations

2.4.1 Facility Partitioning (Disaggregating)

For purposes of the rule, the definition of facility is “any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, which emits or may emit any GHG” (40 CFR 98.6).

Additionally, embedded in the definition of facility per the MRR is a specific provision that grants military facilities (i.e., installations) the ability to classify themselves as more than a single facility (i.e., facility partitioning). “Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties” (40 CFR 98.6). The process of dividing a facility based on functional and or distinct groupings is referred to as facility partitioning. Therefore, a facility can potentially avoid triggering the MRR when emissions are partitioned into more than one facility. ***Refer to Section 2-6 if there is a change in operators.***

Each installation should consider the entire definition of “facility” under the MRR, including the specific provision for military facilities. One approach would be to keep an installation’s decision to subdivide into multiple facilities consistent with the application of similar provisions for defining a facility or source that is provided in EPA major source guidance for military installations (*Major Source Determinations for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act*, 2 August 1996). A facility is not required to have applied the major source guidance for installation definition previously in order to use it for the GHG reporting requirements. However, if the major source guidance has been used previously, its use for GHG reporting should be consistent with the previous application.

Several examples are provided below demonstrating how the facility definition may be applied. Installations should refer to major source guidance for more details and consult with local area USAF counsel.

- <u>Common Control</u>: Common control is, in general, the authority of the single highest commanding entity that exercises restraining or directing influence over a facility's economic or other relevant, pollutant-emitting activities. The common control authority has the power and authority to guide, manage, or regulate the pollutant-emitting activities of a facility, including the power to make or veto decisions to implement major emission-control measures to influence production levels or compliance with environmental regulations. In other words, common control should be evaluated at the highest point of a facility’s command structure. Pollutant-emitting activities that are under the control of different military services, defense agencies, or National Guard are not under common control.

- Functional Grouping: EPA has acknowledged that military installations are often combinations of functionally distinct groupings of pollutant-emitting activities that may be distinguished the same way that industrial and commercial sources are. For example, a complex facility may operate an airfield, a maintenance depot, a school for infantry training, and a research and development laboratory. Per EPA's guidance, each of these activities may be a separate functional grouping.

- Non-Military Activities: Military installations include numerous activities that are not directly related to the military mission and are not normally found at other types of industrial sources. These types of activities include residential housing, schools, day care centers, churches, recreational parks, theaters, shopping centers, grocery stores, gas stations, and dry cleaners. Because these amenities typically do not represent essential activities related to the primary military activities of the installation, EPA believes it may be inappropriate to consider these as support facilities to the primary military activities. As such, these activities may be treated as separate sources for all purposes for which an industrial grouping distinction is allowed.

  However, there are instances where similar types of activities do function as support facilities to the primary military activities at an installation, and in these instances, they should be grouped with the primary military activities that they support. For example, food services that support troops in barracks at basic training camps would be grouped with other emissions units associated with the basic training operations, but a fast food chain outlet would not.

- Support Activities: Support activities at military installations (e.g., boilers and wastewater treatment facilities) could be aggregated with their associated functional grouping. Consequently, emissions from support facilities would be added to the emissions from the primary activity when determining the GHG emissions from the "source." Emissions sources that support non-military activities would be associated with the non-military functional grouping that receives the majority of their products or services. For example, a boiler supporting an elementary school at the military installation would be grouped with the elementary school and not with other boilers that provide steam to a maintenance depot.

  Where an activity supports more than one function, it usually would be aggregated with the primary activity to which it contributes 50 percent or more of its output. For example, a central steam plant may provide heat to most facilities on an installation. The GHG emissions from the plant would be aggregated with the primary activity of the installation, which may be maintenance, airfield operations, troop training, etc.

- Leased Activities: Leased activities may be considered under separate control from activities under the control of the military-controlling entities at an installation. These leased activities would be considered "tenants" on military installations. They may include restaurants, banks, and schools. In contrast, contract-for-service (or contractor-operated) activities at military installations usually would be considered under the control of the military entity that controls the contract. Leased activities are different from contract-for-service activities, as discussed in the major source guidance.

2.4.2 Air Force-Specific Source Categories

Once a facility has been defined, evaluate it to determine if any sources categories are present.

Figure 2-1, *Determining Air Force Facilities Subject to MRR*, shows a simplified method to determine if an USAF facility is subject to the MRR.

Some source categories have thresholds that trigger reporting. Each source category should be evaluated for threshold levels. For example, the source category for stationary combustion units require emissions of 25,000 metric tons of CO_2e. Emissions from CO_2, CH_4, and N_2O are summed for a facility using the calculation methodology specific to that source category. For general stationary combustion units, only CH_4 and N_2O emissions from biomass combustions should be included to determine if the MRR threshold has been exceeded.

The following equation is used to sum the emissions for an entire facility and convert the emissions to CO_2e.

$$\mathbf{CO_2e} = \sum_{\mathbf{i=1}}^{\mathbf{n}} \mathbf{GHG_i \times GWP_i}$$

Equation 2-1

Where,

- **CO_2e** = Carbon dioxide equivalent (ton/yr)
- **GHG_i** = Mass emissions of each greenhouse gas (ton/yr)
- **GWP_i** = Global warming potential for each greenhouse gas from Table 2-4 *Global Warming Potentials.*
- **n** = The number of greenhouse gases emitted

Additionally, facilities that only have stationary combustion units as MRR applicable source categories must also quantify the aggregate maximum rated heat input capacity to determine whether the facility has exceeded the 30 million British thermal units per hour (MMBtu/hr) threshold. The EPA provides worksheets to aid in these quantifying calculations.

Again, each source category has a particular calculation methodology (or methodologies) for GHG emissions calculations or calculations for a particular factor to determine applicability.

If it is determined that a facility is not subject to the MRR, it is advisable that MRR applicability is reevaluated when there are changes at the facility that may increase emissions. Types of changes that may affect emissions are changes in fuel use, operating hours, and facility expansion.

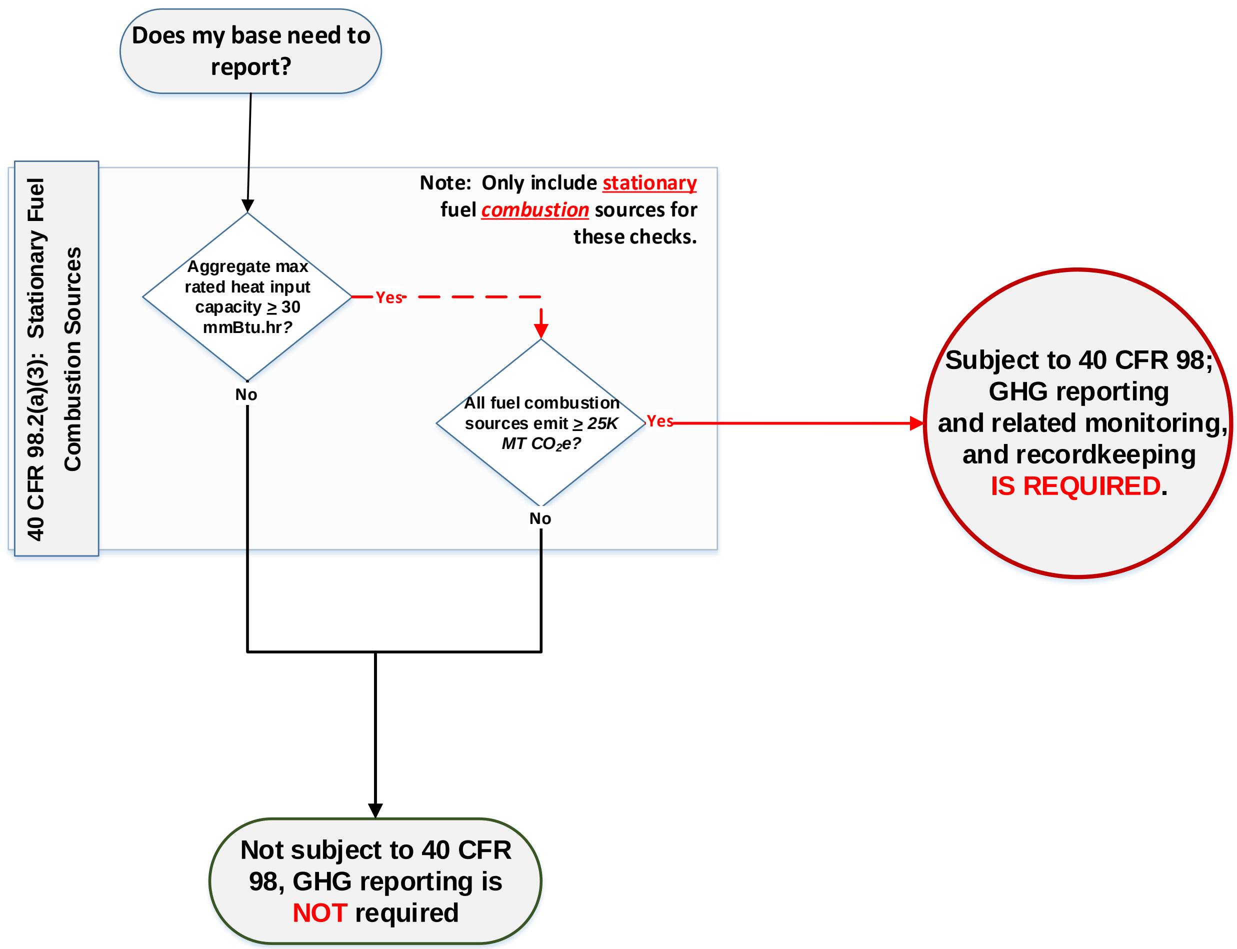

Figure 2-1 Determining Air Force Facilities Subject to MRR

Table 2-4 Global Warming Potentials

Name	Chemical Formula	CAS No.	Global Warming Potential (100 yr.)
Carbon Dioxide	CO_2	124-38-9	1
Methane	CH_4	74-82-8	25(1)
Nitrous Oxide	N_2O	10024-97-2	298(1)

SOURCE Table A-1 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.
[1]The GWP for this compound was updated in the final rule published on November 29, 2013 [78 FR 71904] and effective on January 1, 2014.

2.5 Designated Representative

NOTE: If Confidential Business Information (CBI) is being reported, please note that the Designated Representative (DR), Alternate Designated Representative (ADR), and Agent(s) have equal ability to access, view, enter and submit all e-GGRT data for the installation. Make sure that any persons appointed to these positions have the appropriate security clearances and that the designations in e-GGRT for the facility are up to date.

Per 40 CFR 98.4(c), the DR/ADR (and the Agent acting under delegated authority) will legally bind the facility through their representations, actions, inactions, or submissions. Additionally, the owners and operators of the facility will be bound to any court or EPA orders or decisions that result from DR/ADR activities (including any omissions) under the MRR. This can result in significant consequences not only for the DR/ADR, but also for the DoD, USAF, the Installation, and the Commanding Officer; including the possibility of fines and imprisonment.

2.5.1 Roles and Responsibilities

The MRR contains three different roles of responsibility for reporting data, which are specified in 40 CFR 98.4. Every facility reporting under the MRR is required to have a person assigned to the DR role; however, assigning individuals to the ADR and Agent roles is discretionary. The roles and responsibilities are described as follows:

- **Designated Representative (DR):**
  - The facility must have one, but only one, DR.
  - A DR can prepare a report. The DR is also responsible for signing and submitting reports and other information on behalf of the USAF facility/Installation and certifying that reports and submissions to the EPA under the MRR are true, accurate, and complete.

  - The DR may appoint (or confirm the appointment of) an ADR and one or more Agents who can act on his/her behalf.

- **Alternate Designated Representative (ADR):**
  - The facility/installation may have one, but only one, ADR (appointing an ADR is optional, but it is advised to do so).
  - An ADR can prepare a report for signature by another person. The ADR is also responsible (in the absence of the DR) for signing and submitting reports and other information on behalf of the DR, and certifying that reports and submissions to the EPA under the MRR are true, accurate, and complete. Any representation, action, inaction, or submission by the ADR is deemed to be a representation, action, inaction, or submission by the DR.
  - The ADR may appoint (or confirm the appointment of) one or more Agents who can act on his or her behalf.

- **Agent** (there is no requirement that the DR and ADR appoint the same Agents)**:**
  - The facility/installation can have an unlimited number of Agents or none.
  - The Agent has specific delegated authority, depending on which authorities have been delegated to him or her from the DR or ADR. Agents can prepare a report for signature by another person (DR or ADR). Before an Agent can submit an electronic submission, the EPA Administrator must receive an electronic Notice of Delegation from the DR or the ADR specific for that Agent. The electronic Notice of Delegation must include the certification statement in 40 CFR 98.4(m)(v)(A), and as indicated by the certification statement, an electronic submission by the Agent is considered to be certified, signed, and submitted by the delegating DR or ADR.
  - A DR or ADR can delegate authorities to the Agent (not responsibility). An Agent cannot delegate authorities to another Agent.

2.5.1.1 Role Duplication Requirement

The DR must be the same person and assigned the same representative role if the facility is subject to both the Acid Rain Program (40 CFR 75) and MRR [40 CFR 98.4(a)]. Because the ADR assumes responsibilities in the absence of the DR, the duplication requirement applies for that role as well. The requirement for maintaining the same person in their respective DR and ADR roles also applies to the Clean Air Interstate Rule (CAIR) and to many of the state GHG reporting programs. As a result, the DR (and ADR in the DR's absence) may be responsible for multiple programs and requirements.

2.5.1.2 Representative Certification of the Greenhouse Gas Emissions Report

One of the most important responsibilities for the DR and ADR is certifying, signing, and submitting the annual GHG emissions report on behalf of the Installation. In accordance with 40 CFR 98.5, each submission is required to include the following compliance certification statement signed by the DR/ADR:

> "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

2.5.2 Authorization of the Designated and Alternate Designated Representative

Authorization of the DR and ADR is the process for granting the appointed individual(s) access to the facility's data and the ability to act on behalf of the facility for the MRR. Registration of the facility into e-GGRT is required for reporting emissions and the process begins with designating a DR (and ADR if one is selected). It is important that the name, phone number, and email address for the appointed individual(s) is provided to the person responsible for the facility's initial registration in e-GGRT or to the person responsible for entering the data for subsequent designations into the DR/ADR roles. The process of authorization of the DR/ADR is similar:

1) The Document of Agreement appointing the DR and (optionally) the ADR to his or her role is prepared and signed (this can be accomplished by a Letter of Appointment signed by the USAF Installation's Commanding Officer).

2) The appointed DR and/or ADR information is entered into e-GGRT for EPA review (the proposed DR/ADR must create an e-GGRT user account if he or she does not already have one).

    a. The facility registration begins with the identification of the DR and entry of the appointed DR's information. The ADR can be entered during facility registration or later.

    b. If the facility is also subject to the Acid Rain Program, e-GGRT and the Clean Air Markets Division (CAMD) business system (used for reporting to the Acid Rain

Program) are integrated to make it easier for facilities who use both systems. The DR and ADR information from the CAMD business system will import into e-GGRT during the user registration process. Keep in mind that the DR/ADR must be the same person(s) for both programs.

3) All DR/ADR appointments are reviewed by the EPA. After EPA approval, the proposed DR/ADR will be emailed an invitation with a code and instructions on how to accept or reject the role.

4) The proposed DR/ADR logins in to e-GGRT and accepts (or rejects) the role and electronically signs the Certificate of Representation. This step cannot be performed until the proposed DR/ADR creates an e-GGRT user account and EPA approves his or her Electronic Signature Agreement.

    a. The DR can designate or confirm the ADR during the role acceptance process or at a later time.

    b. The DR and ADR can each delegate authority to Agents during the role acceptance process or at a later time.

5) The Certificate of Representation will be valid and the appointment of the DR/ADR will be considered current until a new Certificate of Representation is received by the EPA Administrator.

NOTE: Alternatively, the Certificate of Representation can be completed and submitted in a format approved by the EPA Administrator (some Administrators have specific forms available and/or require electronic submission); however, the entry of the DR/ADR information and electronic signature of the Certificate of Representation will still be required through e-GGRT.

2.5.2.1 Document of Agreement

Per the wording of the Certificate of Representation, the DR and ADR must have an agreement binding on the owner and operator of the facility. For the USAF, the installation's Commanding Officer, as the "Responsible Official" under the CAA, is the de facto MRR reporting official. Therefore, the DR and ADR should be appointed through a letter issued and signed by the USAF installation's Commanding Officer and accepted by the person(s) appointed as DR/ADR. The letter appointing the ADR must also include a procedure for authorizing the ADR to act in lieu of the DR [40 CFR 98.4(f)].

Unless otherwise required by the EPA Administrator, the Document of Agreement (such as the Letter of Appointment) is not required to be submitted to the EPA Administrator. Likewise, the EPA Administrator is not under any obligation to review or evaluate the document of agreement (either form or content). The following is a sample of an appointment letter (memorandum):

Sample Appointment Letter

MEMORANDUM FOR “Office Symbol of Appointees”

FROM: "Organization"

SUBJECT: Base Designated Greenhouse Gas (GHG) Reporting Representatives Appointment

1. Per 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, a Designated GHG Representative and an alternate are appointed who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions to the Environmental Protection Agency (EPA) relating to mandatory GHG reporting.

3. The Alternative Designated Representative shall act in lieu of the Designated Representative at any time the Designated Representative is not able to fulfill his or her responsibilities under the mandatory GHG reporting rule due to absence or other circumstance.

4. The following individuals from the “insert organization” are appointed as Designated GHG Reporting Representatives

5. The Designated Representative and alternate indicate acceptance of their appointed rules and responsibilities under the mandatory GHG reporting rule by signing and submitting the Certificate of Representation to the appropriate EPA Administrator.

Rank/Name	Office Symbol	Duty Phone
Primary:		
Alternate:		

2. For any additional information, please contact

2.5.2.2 Certificate of Representation

The MRR includes requirements for establishing the DR/ADR through the submittal of a Certificate of Representation at least 60 days prior to the deadline for submission of the emission report. The following events require the DR (and ADR if any) to sign, certify and resubmit a Certificate of Representation for a facility:

- Updates to the name, address, email, fax or telephone for the DR (or ADR if any). This includes replacing an existing DR or ADR or adding an ADR.
- Updates to the facility profile (facility name, street address, owner/operator information)

The document needs to include at least the following elements to be complete (the certification statements are included in the Certificate of Representation that is electronically signed in e-GGRT and will contain the facility's profile information):

- Identification of the facility which the certificate of representation is submitted (the name and location of the USAF installation).
- The name, organization name (company affiliation-employer), physical (street) address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the DR and any ADR.
- A list of the owners and operators of the facility (use a statement which corresponds to how the facility is defined for MRR reporting; for example, "owned and operated by Federal Government (United States Department of the Air Force)", "Controlled by United States Department of the Air Force", "Travis Air Force Base is a United States Air Force air base under the operational control of the Air Mobility Command (AMC)").
- The following certification statements by the DR and any ADR:
    - "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable."
    - "I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions."
    - "I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier."

  - "If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier."

- The certificate must include the signature of the DR/ADR and the date the certificate is signed. This is accomplished through electronic signature if using e-GGRT.

NOTE: For initial Certificate of Representations submitted after 1 January 2018, the certificate must also include a list of the subparts that are anticipated by the facility to be included in the annual GHG report. The list of potentially applicable subparts does not need to be revised with revisions to the certificate or if the actual applicable subparts change [40 CFR §98.4(i)(6)].

2.5.2.3 Change or Removal of Representative

After the initial appointments, situations may arise when the DR or ADR needs to be changed or removed from their respective roles. Anytime there is a change in DR or ADR, another Document of Agreement is needed (such as an appointment letter from the installation's Commanding Officer). The DR or ADR may be changed at any time by completing, signing, and submitting a new Certification of Representation to the EPA Administrator (preferably through e-GGRT).

- **Change of DR**: The DR, ADR, or Agent may initiate a change in DR in e-GGRT. Keep in mind that a facility MUST have a DR, so <u>the DR cannot be removed without being replaced</u>. There are two options for replacing the DR; creating a new DR or promoting the ADR into the DR role:

  - <u>Create a new DR</u>: The DR, ADR, or Agent creates an "invitation" to the appointed DR through the Facilities Management tab in e-GGRT. Upon the appointed DR's acceptance of the invitation and signing of the Certificate of Representation, the outgoing DR will be replaced with the appointed DR (this is a simultaneous process).

  - <u>Promoting the ADR to DR</u>: If the current ADR has been appointed to replace the current DR, this action can be completed easily through the e-GGRT system by logging into e-GGRT and selecting the "Promote the ADR" option and clicking on the continue button. Alternatively, a new Certificate of Representation, submitted in the format approved by the EPA Administrator, will replace the previous DR with a new DR or promote the ADR into the role of DR (the change will not become effective until the certificate is <u>received</u> by the EPA Administrator).

- **Change or Removal of ADR**: Since the appointment of an ADR is optional, an ADR can be removed from the role with or without the appointment of a replacement (after the initial facility registration into e-GGRT, ONLY the DR may change or remove the ADR through e-GGRT). Only the DR may change or remove the ADR in e-GGRT. Alternatively, a new Certificate of Representation, submitted in the format approved by the EPA Administrator, will replace the previous DR with a new DR or promote the ADR into the role of DR (the change will not become effective until the certificate is received by the EPA Administrator).
  - If the current ADR is removed without a replacement, a new ADR can be added at a later date.

- **Agents of outgoing DR/ADR**: When there is a change in DR or ADR, the outgoing person and all of his or her Agents (if any) will no longer be able to access data for the facility/installation. The Agents will need to be reappointed by the new DR or ADR to have access to the facility in e-GGRT. However, if an ADR is "promoted" to DR, that person can retain any Agents he or she had as an ADR by signing a revised Notice of Delegation.

NOTE: As soon as the new Certificate of Representation is complete and accepted by the EPA, the change takes effect immediately; however, the new DR/ADR and owners/operators of the facility will be bound by all representations, actions, inaction, and submissions by the previous person in that role until the new Certificate of Representation (or removal of the ADR) is accepted by the EPA Administrator.

2.5.3 Delegated Authority to Agents

The DR and/or ADR may require assistance (consultation, data entry and verification, etc.) with the GHG emissions reporting process. For this reason, the EPA allows each DR and ADR to delegate authority to an unlimited number of Agents for each facility. This delegation of authority should not be taken lightly; Agents are able to access all of the facility's data and can complete or review the annual GHG reports (and any other submissions to the EPA). Additionally, any electronic submissions made by an Agent to the EPA will be considered to be certified, signed, and submitted by the DR (or ADR) that delegated such authority to the Agent. The process of the DR/ADR to delegate authority to an Agent is as follows:

1) The delegation must be made electronically through e-GGRT by the DR/ADR logging into the e-GGRT system and submitting the proposed Agent's name, phone number, and email address to the EPA for review.
   a. All Agents must be e-GGRT users. If the new Agent is not currently a user, he or she should begin the e-GGRT user registration process immediately.

b. There is no alternative procedure for delegating authority to an Agent.

2) After the DR or ADR enters the proposed Agent's information into e-GGRT, a request will be electronically sent to the EPA to approve the Agent. EPA will review the delegation(s) and if approved, will email the proposed Agent an invitation containing an invitation code and instructions on how to accept the role.

3) The proposed Agent must log in to e-GGRT to accept his or her role by entering the invitation code. This step cannot be performed until the proposed Agent creates an e-GGRT user account and EPA approves his or her Electronic Signature Agreement.

4) After the Agent accepts the role, the DR/ADR must then log in to e-GGRT to sign an electronic Notice of Delegation confirming his/her appointment of the Agent.

5) The delegation of authority remains in place until another notice is submitted to the EPA Administrator that eliminates the Agent's delegation of authority.

2.5.3.1 Notice of Delegation

The Notice of Delegation includes the following elements:

- The name, organization name (company affiliation-employer) address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the DR or ADR that appointed the Agent.
- The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of the Agent.
- A list of the type or types of electronic submissions under for which authority is delegated to the Agent.
- Identification of the facility for which the electronic submission may be made by the Agent.
- The following certification statements must be made by the DR or ADR that appointed he Agent:
    - "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under § 98.4(m)(3) shall be deemed to be an electronic submission certified, signed, and submitted by me."

  - "Until this notice of delegation is superseded by a later signed notice of delegation under § 98.4(m)(3), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 98.4(m) is terminated."
- The signature of the DR or ADR that appointed the Agent and the date signed (the notice is electronically signed through e-GGRT).

2.5.3.2 Elimination of an Agent's Authority

To remove an existing Agent, the DR/ADR may remove the Agent specific to him or herself by logging into e-GGRT and following the instructions provided in the Facility Management tab. The DR cannot remove the ADR's Agents and vice versa. However, when the DR or ADR is removed from their roles, their respective Agents are also removed (except for when an ADR is promoted to DR, but a new Notice of Delegation will be required for those Agents).

An Agent may remove him/herself through e-GGRT; however, the Agent cannot remove another Agent.

2.6 Change in Owners or Operators

Some facilities may need to address a change in owners or operators. Types of situations that might require owner or operator changes are facility partitioning or the discovery of an error in the original list submitted to the EPA. Additionally, privatization and Base Realignment and Closure (BRAC) may involve the transfer of ownership to a new entity.

2.7 Facility Partitioning and Errors

When a facility is partitioned or there is an error in the list of operators or owners, the certificate of representation must be amended and submitted to the EPA within 90 days to reflect any changes in owners or operators. Refer to Section 2.4.1 for further explanation of facility partitioning.

Any owner or operator of a facility omitted from the certificate of representation is still subject to and bound by the certificate of representation and submissions of the designated representative.

2.8 New Owner or Operator

There may be situations where a change in operator at an Air Force base may occur. Two examples of such situations are provided below:

- Privatization
- Base Realignment and Closure

The process to change operators is two-step. First, the DR and ADR from the current operator must be replaced by a new DR and ADR from the new operator. This is accomplished through e-GGRT. The second step is the resubmission of a new Certificate of Representation within 90 days of the change.

2.9 Reports and Documentation

The annual GHG emissions report must be submitted no later than March 31 of each calendar year for the GHG emissions from the previous calendar year (January 1 through December 31). If a facility becomes subject to the MRR during the course of a year because of operation or physical changes, begin reporting within the first month of those changes and end on December 31 of that year. It is important to retain all documents used to derive the GHG emissions compiled in the annual report (e.g., maintenance records, calibration records, calculation methodology).

2.9.1 Contents of the Annual Emissions Report

The EPA requires several types of documents to be submitted in the annual emissions report or be kept in possession by the facility. Data required to be included in an annual emissions report include:

- Installation Identification
- Dates of Importance
- Emissions Data
- Explanation of Calculation Changes, if applicable
- Explanation of Missing Data, if applicable
- Certification Statement
- North American Industry Classification System (NAICS) Codes
- Parent Company Identification
- Plant Code, if applicable

Each of these components of the report are described in the following sections. This is a general report content list applicable to all source categories and is specific to facility-level information. The EPA may review the report and any other documents to verify completeness and accuracy via periodic audits.

2.9.2 Installation Identification

The report must contain the name and physical street address of the installation. If the facility has no physical street address, latitude and longitude coordinates of the center point of the facility may be substituted.

2.9.3 Dates of Importance

The years and months of emissions that are being reported must be noted. In addition, the date of report submitted to the EPA must also be noted. The report must be submitted no later than March 31 of each calendar year and reflect emissions for the previous calendar year.

2.9.4 Emissions Data

Emissions from applicable sources at the facility must be contained in the report. For the majority of Air Force installations, the most commonly reported GHG emissions will be CO_2, CH_4, and N_2O from stationary fuel combustion sources. The emissions of each GHG must be converted to CO_2 equivalent (CO_2e) and summed. A facility must also indicate whether reported emissions data include emissions from a cogeneration unit located at the facility. Note that biogenic emissions are calculated in the same manner as emissions from the combustion of other fuels, but are reported in a separate component of the annual GHG report. An in-depth discussion of applicable sources and emissions data for Air Force installations is provided in this document.

2.9.5 Explanation of Calculation Changes

The method for calculating GHG emissions is specific for each source category and is described in the appropriate subsection of 40 CFR 98. The method must be used within the same source category and throughout the reporting time frame. A written explanation is required any time the methodology used to compile the emissions report deviates from the calculation method stipulated in the CFR.

2.9.6 Missing Data

In the event that quality-assured data is unavailable (such a malfunctioning of equipment or if a required fuel sample is not taken), substitute data may be used in place of missing parameters in calculations. The procedure for estimating missing data is source category specific and is discussed in the applicable sections within this guide.

2.9.7 Certification Statement

Each MRR report submitted to the EPA must contain a GHG emissions report certification statement, as shown earlier in this Chapter. It must be signed and dated by the designated representative or alternate designated representative of the owners/operators of the facility.

2.9.8 NAICS Codes

Federal statistical agencies use the North American Industry Classification System (NAICS) to classify business establishments for the purpose of data collection related to the U.S. economy. Each report should include the NAICS code(s) applicable to the facility.

2.9.9 Parent Company Identification

One of the objectives of the MRR is to identify the GHG emissions from United States parent companies. For Air Force installations, the parent company should be identified as "U.S. Government." In this instance, no information regarding the parent company physical address or percent ownership of the facility by the parent company should be included in the report.

2.9.10 Applicable "Plant Code"

Plant codes are assigned by either the Department of Energy's Energy Information Administration or by the EPA's Clean Air Markets Division. The plant code reporting requirement applies to each stationary combustion source (i.e., each individual unit and each group of units reported as a configuration) that includes at least one combustion unit that has been assigned a plant code.

2.9.11 Revisions

There may be a need to revise an annual GHG emissions report. Per 40 CFR 98.3 (h), "A substantive error is an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified." The owner/operator is compelled to submit a revised/corrected GHG emissions report within 45 days of discovering the error(s). Another scenario that prompts an annual GHG emission report revision is if the EPA notifies the owner/operator in writing that errors were found in the report and identifies each substantive error. The owner/operator has 45 days of the receipt of notification to either resubmit the report that corrects each identified substantive error or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not substantive.

Extensions of the 45-day period to submit the revised report may be approved by the EPA upon request by the owner/operator. If a request for extension of the 45-day period for submission is received by the EPA via email before the end of the initial 45-day period for submission, the request is automatically granted for 30 days. Additional days beyond the 30-day extension may be granted by the EPA provided that the owners/operators submitted a request at least five (5) days prior to the expiration of a 30-day extension. This request must demonstrate that it is not practicable to submit a revised report within 75 days from the initial notification of a substantive error. The EPA will grant this extension if the request shows to the EPA's satisfaction that it is not practicable to resolve substantial errors within 75 days.

2.10 Recordkeeping

Retain all records required under the MRR for at least five (5) years from the date of submission of the annual GHG report for the reporting year in which the record was made. Records must be made available for inspection and review by the EPA upon request. The following is a list of documents that are to be retained, though additional documents may be required for specific source categories:

- Source List.
- Data.
- Annual Emissions Reports.
- GHG Monitoring Plan.
- Test Results.
- Maintenance Records.

2.10.1 Source List

The source list includes all units, operations, processes, and activities for which GHG emissions were calculated.

2.10.2 Data

Documents pertaining to data used to calculate GHG emissions for each unit, operation, process, and activity must be kept and categorized by fuel or material type. This data must include GHG emissions calculations and methods/analytical results used for the development of site-specific emission factors. Furthermore, results of all required analyses for High Heat Value (HHV), carbon content, and other required fuel parameters as well as any facility operating data or process information used for the GHG emission calculations must be retained. For missing data computations, a record describing the event that caused the missing data and the corrective actions taken to remedy the lack of data values (i.e., restoration of malfunctioning equipment) must be maintained.

2.10.3 Annual Emissions Reports

Annual GHG reports and any revisions must be retained even after submission to the EPA.

2.10.4 GHG Monitoring Plan

All facilities required to report under the MRR are required to develop and maintain a GHG Monitoring Plan. In accordance with 40 CFR 98.3 (g)(5)(i), at a minimum, the GHG Monitoring Plan shall include the following three elements:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

According to 40 CFR 98.3 (g)(5)(ii), the GHG Monitoring Plan may rely on references to existing corporate documents that provided the elements required above. As such it is intended that this guide, the Air Emissions Guide for Stationary Sources, 40 CFR part 60 appendix F (Quality Assurance Procedures) and 40 CFR Part 75 Appendix B (Quality Assurance and Quality Control Procedures) are to be used as the basis for an installation-specific GHG Monitoring Plan. Therefore, an installation-specific GHG Monitoring Plan should basically only include the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
    - In accordance with AFI 32-7040, the Base Civil Engineer-Installation Management Flight is responsible for all air quality emissions inventories (including GHGs).
    - Additionally, each facility subject to GHG reporting under the MRR shall, in writing, designate a representative and one alternate (40 CFR 98.4 (a), see section 2.4 for details). The Installation/Center Commander should designate an individual as the designated representative through a letter of appointment.

- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

- All GHG calculations, the processes, and methods are to be included by reference (not reiteration) in accordance with the following USAF guidance:
  - Guide to The Mandatory Greenhouse Gas Reporting Rule (this document)
  - Air Emissions Guide for Stationary Sources
- In accordance with AFI 32-7040, all air quality compliance data, including greenhouse gas emissions, are entered and maintained in APIMS.
- Any installation-specific special data collection processes and methods used to collect the necessary data that do not conflict with the processes and methods described in the Guide to The Mandatory Greenhouse Gas Reporting Rule (this document) and the Air Emissions Guide for Stationary Sources.

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.
  - The procedures and methods used for quality assurance, maintenance, and repair methods are to be included by reference (not reiteration) in accordance with the following:
    - Guide to The Mandatory Greenhouse Gas Reporting Rule (this document)
    - 40 CFR part 60 appendix F, Quality Assurance Procedures, and 40 CFR Part 75 Appendix B, Quality Assurance and Quality Control Procedures, shall be included by reference (not reiteration).
  - Any installation-specific special procedures and methods used for quality assurance, maintenance, and repair not already addressed in 40 CFR part 60 appendix F or 40 CFR part 75 appendix B.

Each facility must revise their installation-specific GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime. Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit. Electronic storage of the information in the plan in APIMS is permissible; however, the information must be made available in hard copy upon request during an audit.

2.10.5 Test Results

Documentation showing the results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide GHG data for the annual emissions report must be retained.

2.10.6 Maintenance Records

All maintenance records for continuous monitoring systems, flow meters, and other instrumentation used to provide data must also be kept.

2.11 Stationary Fuel Combustion Units

Per APIMS November 2015 review, the stationary fuel combustion source category is the only source category that may trigger reporting under the MRR at Air Force installations.

For this source category, annual emissions of CO_2, CH_4, and N_2O must be calculated and reported. High Heat Values (HHVs) and emission factors for these GHGs for various fuel types are provided in Table 2-5 *Default CO2 Emission Factors and High Heat Values for Various Types of Fuel*, and Table 2-6 *Default CH4 and N2O Emission Factors for Various Types of Fuel Applicability of MRR*.

2.11.1 Applicability of MRR

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Not all USAF facilities that have stationary fuel combustion units will be subject to the MRR.

Only a facility that, in any calendar year starting in 2010, meets all three of the following conditions is subject to MRR:

- The facility is not a source automatically subject to reporting and the facility is not a production or manufacturing source.
- The **aggregate maximum rated heat input capacity** of the stationary fuel combustion units at the facility is **30 MMBtu/hr or greater**.
- The **facility emits 25,000 metric tons CO_2e or more per year** in combined emissions from all stationary fuel combustion sources.

It is important to note that when determining if a facility has exceeded the 25,000 metric tons of CO_2e applicability threshold, the annual emissions of CO_2, CH_4, and N_2O are summed and converted to carbon dioxide equivalents. Include **only** CH_4 and N_2O emissions from biomass combustion for each general stationary combustion unit (exclude carbon dioxide emissions from the combustion of biomass). Convert all GHGs to CO_2e by multiplying the annual emissions by the global warming potential for the particular gas (See Table 2-4) before summing to determine applicability.

The following is a list of Stationary Fuel Combustion Units required to report under MRR:

- Includes, but is not limited to:
  - Boilers
  - Simple and combined-cycle combustion turbines
  - Engines
  - Incinerators
  - Process heaters
  - Aircraft engine testing

- Does not include:
  - Portable equipment
  - Emergency generators and emergency equipment
  - Irrigation pumps at agricultural operations
  - Pilot lights
  - Flares (See note below about Enclosed Flare Systems)
  - Electricity generating units that are subject to 40 CFR 98 Subpart D
  - Units that combust hazardous waste (as defined in §261.3 of 40 CFR Chapter 1), unless either of the following conditions apply:
    - Continuous Emission Monitors (CEMS) are used to quantify CO_2 mass emissions.
    - Any fuel listed in Table 2-5, *Default CO2 Emission Factors and High Heat Values for Various Types of Fuel*, is also combusted in the unit. If this unit burns any of the fuels listed, then report the GHG emissions from the combusted fuels.

The most current USAF Stationary Source Guide should be consulted and utilized to help identify common stationary combustion units found at USAF facilities.

Note that Enclosed Flare Systems are required to report under Subpart C, in most cases. An enclosed flare system does not meet the definition of flare in 40 CFR 98.6 when it does not have an open flame and it has a means to control air flow. These systems can be thought of as being similar to natural draft process heaters or boilers, which fall under MRR applicability. A flare with a shroud to prevent wind effects is not considered to be an enclosed system. Refer to the EPA GHG MRR help page under "Frequently Asked Questions" and see Question 817 for more information.

Table 2-5 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and coke	**MMBtu/short ton**	**kg CO_2/MMBtu**
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial Sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural Gas	**MMBtu/scf**	**kg CO_2/MMBtu**
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products	**MMBtu/gallon**	**kg CO_2/MMBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied Petroleum Gases (LPG)(1)	0.092	61.71
Propane(1)	0.091	62.87
Propylene(2)	0.091	67.77
Ethane(1)	0.068	59.60
Ethanol	0.084	68.44
Ethylene(2)	0.058	65.96
Isobutane(1)	0.099	64.94
Isobutylene(1)	0.103	68.86
Butane(1)	0.103	64.77
Butylene(1)	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88

Notes for this table are on the next page.

Table 2-5 Default CO2 Emission Factors and High Heat Values for Various Types of Fuel (continued)

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Petroleum Coke	0.143	102.41
Special Naptha	0.125	72.34
Unfinished Oils	0.139	74.54
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Other Fuels-Solid	**MMBtu/short ton**	**kg CO_2/MMBtu**
Municipal Solid Waste	9.95(3)	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Petroleum Coke	30.000	102.41
Other Fuels- Gaseous	**MMBtu/scf**	**kg CO_2/MMBtu**
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas(4)	1.388×10^{-3}	59.00
Biomass Fuels-Solid	**MMBtu/short ton**	**kg CO_2/MMBtu**
Wood and Wood Residuals (dry basis)(5)	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass Fuels-Liquid	**MMBtu/gallon**	**kg CO_2/MMBtu**
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

SOURCE Table C-1 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.

[1]. The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2]Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3]Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4]Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV_w = ((100 - M)/100)*HHV_d$ where HHV_w = wet basis HHV, M = moisture content (percent) and HHV_d = dry basis HHV from Table C-1.

[5]Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV_w = ((100 - M)/100)*HHV_d$ where HHV_w = wet basis HHV, M = moisture content (percent) and HHV_d = dry basis HHV from Table C-1.

Table 2-6 Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Fuel Type	Default CH_4 Emission Factor (kg CH_4/MMBtu)	Default N_2O Emission Factor (kg N_2O/MMBtu)
Coal and Coke (All fuel types in Table 2-5)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table 2-5)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels -Solid (All fuel types listed in Table 2-5, except wood and wood residuals)	3.2×10^{-02}	4.2×10^{-03}
Wood and wood residuals	7.2×10^{-03}	3.6×10^{-03}
Biomass Fuels- Gaseous (All fuel types in Table 2-5)	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels- Liquid (All fuel types in Table 2-5)	1.1×10^{-03}	1.1×10^{-04}

SOURCE Table C-2 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1g of CH_4/MMBtu.

2.12 Calculating GHG emissions

Once an Air Force installation has been determined to be subject to the MRR (the MRR reporting thresholds have been exceeded), the GHG emissions from CO_2, CH_4, and N_2O must be calculated and reported. There are several approaches to calculating these emissions based on parameter specificity and are categorized as Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies. Tier 1 is the most general and uses default values for emissions calculations whereas Tier 4 requires CEMS.

It is important to identify which Tier applies to the subject facility as this will affect which equations are used for calculating GHG emissions. For facilities whose use of Tier 1, Tier 2, or Tier 3 methodology is applicable, the option exists to use a higher Tier methodology when one or more fuels are combusted in a unit. In other words, if a facility is able to use Tier 1, the facility can opt to use a higher Tier, such as Tier 2 or 3. For example, if a 100 MMBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though the Tier 1 calculation methodology is acceptable for both fuels. However, for units that use the Tier 4 calculation methodology, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements. It is important to note that biogenic CO_2 emissions are calculated in the same manner as other fuel combustion sources, but are reported as a separate component in the annual GHG report.

Table 2-7 *Quick Reference Guide to Tier Calculations*, and Figure 2-3, *Reference Flow Chart To Tier Calculations*, are provided as a quick reference guide to aid in selecting the appropriate calculation methodology. Additional information regarding these calculation methods are found in 40 CFR 98. Neither Table 2-7 nor Figure 2-2 should be considered all-inclusive; they are provided in this document to give a general indication of common scenarios and tiers used in those scenarios. Note that there are additional methods for calculating CO_2 mass emissions from sorbent use and biogenic sources not provided in Table 2-7. These additional methodologies are discussed in greater detail at the end of the following chapter.

Table 2-7 Quick Reference Guide to Tier Calculations

Least Precise → Most Precise

Tier	Scenarios for Use	Data Used
1	When High Heat Value is not regularly determined Any fuel from Table 4-1 combusted in a unit ≤250 MMBtu/hr May be used for MSW and/or Tire combustion provided <10% of unit's annual heat input is derived from those fuels May be used for MSW in any unit size with no steam production May be used for any biomass fuel listed in Table 4-1 in any sized unit	Fuel Usage Records Default High Heat Value Default Emission Factors
2	≤ 250 MMBtu/hr and any fuel from Table 4-1, and high heat value determined May be used for MSW in any size unit that produces steam > 250MMBtu/hr that combusts natural gas and/or distillate fuel oil	Fuel Usage Records Measured High Heat Value Default Emission Factor
3	≥ 250 MMBtu/hr and combusts any fuel from Table 4-1 except for MSW, natural gas, and distillate fuel oil	Fuel Measured Directly Measured Fuel Carbon Content and/or Molecular Weight
4	Unit has Continuous Emission Monitoring Systems (CEMS)	Hourly Data from CEMS
Alternative Methodology	For use of units subject to 40 CFR 75	Data Used for Reporting under 40 CFR 75 Requirements

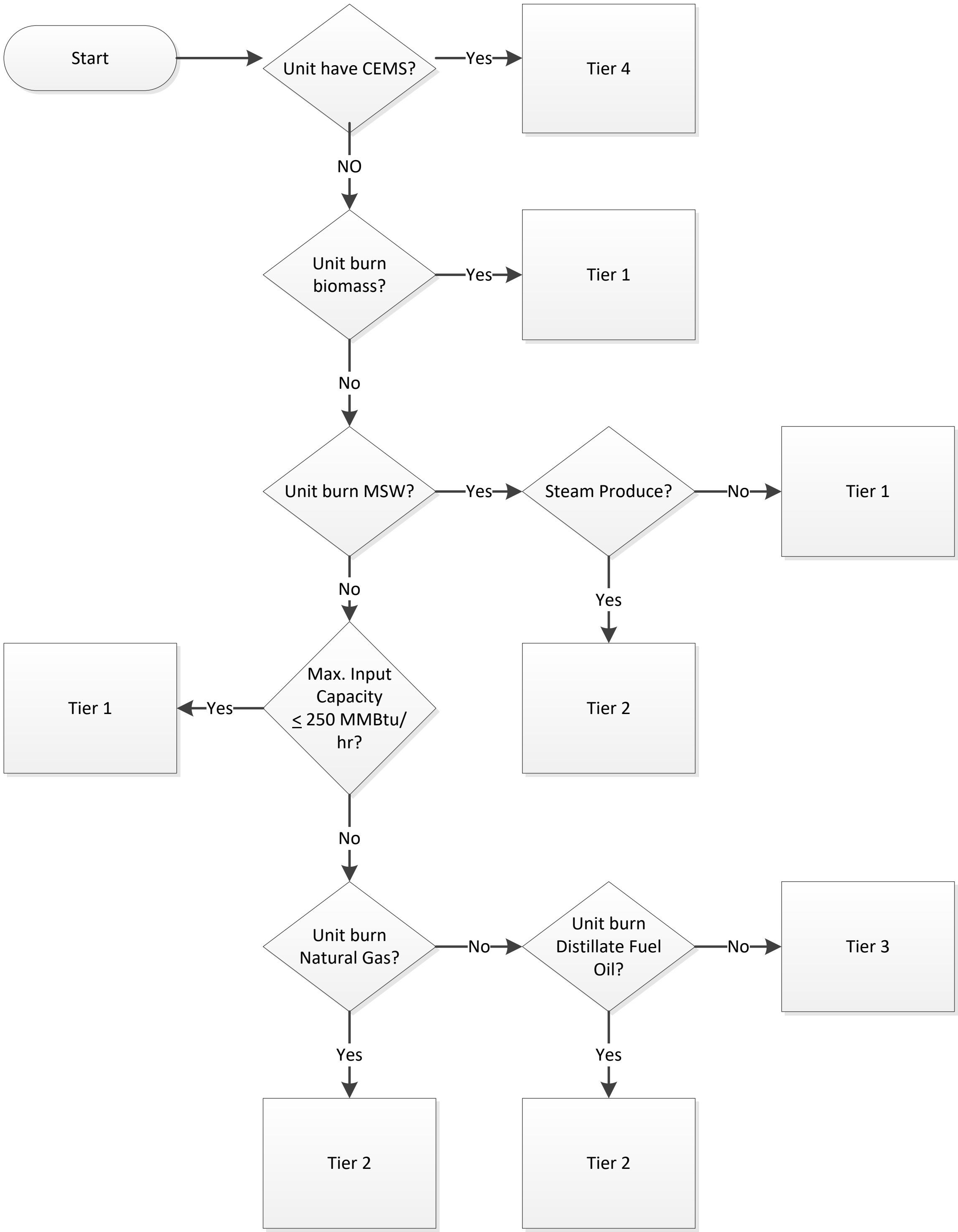

Figure 2-2 Reference Flow Chart to Tier Calculations

2.13 Aircraft Engine Testing and Calculations

Aircraft engine testing and stationary engines are stationary fuel combustion source categories that are not rated in *Maximum Rated Heat Input Capacity* (MMBtu/hr); however, they must still be included as sources when evaluating the applicability of the MRR for a facility against the 30 MMBtu/hr or greater aggregate maximum rated heat input capacity threshold for the stationary fuel combustion units as specified in 40 CFR 98.2(a)(3). For these sources the *Maximum Rated Heat Input Capacity* can easily be derived based on the fuel Heating Value (HV*)*, see Table 2-8, *Maximum Rated Heat Input Capacity (C) for Aircraft Engine Testing, and Fuel Consumption Rate* (*q*). For stationary engines the equation is as follows:

$$\boldsymbol{C}\left(\frac{\boldsymbol{MMBtu}}{\boldsymbol{hr}}\right)=\boldsymbol{HV}\left(\frac{\boldsymbol{MMBtu}}{\boldsymbol{gal}}\right)\times\boldsymbol{q}\left(\frac{\boldsymbol{gal}}{\boldsymbol{hr}}\right)$$

Equation 2-2

Where:

C	=	Maximum rated heat input capacity (MMBtu/hr)
HV	=	Heating value of the fuel used (MMBtu/gal)
q	=	Fuel consumption rate (gal/hr)

For aircraft engine testing, the engine may have several throttle settings that result in different fuel consumption rates over several time intervals. Therefore, for aircraft engine testing you must modify the above equation with a time-weighted averaging of the fuel consumption to calculate maximum rated heat input capacity as shown below:

$$\boldsymbol{C}\left(\frac{\boldsymbol{MMBtu}}{\boldsymbol{hr}}\right)=\boldsymbol{HV}\left(\frac{\boldsymbol{MMBtu}}{\boldsymbol{gal}}\right)\times\frac{\sum_{i}^{n}\boldsymbol{q_i}\times\boldsymbol{t_i}}{\sum_{i}^{n}\boldsymbol{t_i}}\left(\frac{\boldsymbol{gal}}{\boldsymbol{hr}}\right)$$

Equation 2-3

Where:

C	=	Maximum rated heat input capacity (MMBtu/hr)
HV	=	Heating value of the fuel used (MMBtu/gal)
$\mathbf{q_i}$	=	Fuel consumption rate (gal/hr) at throttle setting i
$\mathbf{t_i}$	=	Time (hr) operated at throttle setting i

To simplify this process, the *Maximum Rated Heat Input Capacity (C)* for various USAF aircraft engine testing is already calculated (see Table 2-8). These values were estimated based on February 2014 Air Program Management System (APIMS) runtime data for all aircraft engines and respective fuel flow rates from AF 2014 Mobile Source Guide. Actual *C* values for a specific engine are the USAF-wide average of all 2014 engine runs for the specified engine. Consult the latest Mobile Source Guide for the most current numbers.

Table 2-8 Maximum Rated Heat Input Capacity (C) for Aircraft Engine Testing

Aircraft Engine	Max. Heat Input Capacity (MMBtu/hr)	Aircraft Engine	Max. Heat Input Capacity (MMBtu/hr)
F100-PW-100	106	J79-GE-17	82
F100-PW-200	69	J85-GE-5F	38
F100-PW-220	108	J85-GE-5H	49
F100-PW-229	77	J85-GE-5M	46
F101-GE-102	94	T56-A-7	25
F108-CF-100	60	T56-A-9	34
F110-GE-100	107	T56-A-14	13
F110-GE-129	72	T56-A-15	29
F117-PW-100	46	TF33-P-9	87
F118-GE-100	41	TF33-P-102A	80
F119-PW-100	158	TF34-GE-100	15
F404-GE-400	94	TF34-GE-100A	22
J69-T-25	18	TF39-GE-1C	160

2.14 Calculation Methods for Stationary Fuel Combustion Units

There are a variety of calculation methods available to quantify annual GHG emissions from stationary fuel combustion units. For units that combust both biomass and fossil fuels, CO_2 emissions from the combustion of biomass must be calculated and reported separately. When multiple fuels are combusted during the reporting year, sum the fuel-specific results from the applicable equations to obtain the total annual CO_2, CH_4, and N_2O emissions, in metric tons. The equations used for the calculation of GHG emissions is determined by the Tier applicable to the subject facility. Calculation spreadsheets are available to aid the user in performing these calculations. If these spreadsheets are used, they (or any other material used to calculate emissions) retain them as part of the record-keeping requirements. A detailed description of each Tier is provided below.

2.14.1 Tier 1 Calculation Methodology

Tier 1 will likely be the most common calculation methodology used by Air Force facilities. It is the most general of the calculation methodologies, utilizing default emission factors and default HHV of fuels.

2.14.2 Tier 1 Applicability

The following are conditions, requirements, and restrictions for the use of Tier 1 for calculating CO_2 emissions:

- May not be used if the owner/operator routinely performs fuel sampling and analysis for the fuel HHV or is routinely given this information from the supplier at a minimum frequency or greater than the minimum required for Tier 2 methodology. The frequency is fuel-specific as provided in 40 CR 98.34(a) and is discussed in the Monitoring and Quality Assurance/Quality Control (QA/QC) Requirements Chapter (Chapter 2.21) in this guide. Possession of such data triggers the requirement of Tier 2 Calculation Methodology, except where noted below.

- May be used for any fuel listed in Table 2-5 that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less.

- May be used for the combustion of MSW in a unit of any size that does not produce steam as long as Tier 4 Calculation Methodology is not required. **Note: Acquisition of data for fuel sampling and analysis results at a frequency equal to or greater than that specified in 40 CFR 98.34(a) does <u>not</u> trigger Tier 2 Calculation Methodology.**

- Can be used for solid, gaseous, or liquid biomass fuels in a unit of any size given that the fuel is listed in Table 2-5.

- May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consumption is obtained from fuel billing records in units of therms or MMBtu. **Note: Acquisition of data for fuel sampling and analysis results at a frequency equal to or greater than that specified in 40 CFR 98.34(a) does <u>not</u> trigger Tier 2 Calculation Methodology.**

- May be used for MSW combustion in a small, batch incinerator that burns no more than 1000 tons per year. **Note: Acquisition of data for fuel sampling and analysis results at a frequency equal to or greater than that specified in 40 CFR 98.34(a) does <u>not</u> trigger Tier 2 Calculation Methodology.**

- May be used for the combustion of MSW and/or tires in a unit as long as no more than 10 percent of the unit's annual heat input is derived from those combined fuels. If a unit combusts both MSW and tires and the reporter elects not to separately calculate and report biogenic CO_2 emissions from the combustion of tires, Tier 1 can be used for the MSW combustion, as long as no more than 10 percent of the unit's annual heat input is derived from MSW. **Note: Acquisition of data for fuel sampling and analysis results at a frequency equal to or greater than that specified in 40 CFR 98.34(a) does <u>not</u> trigger Tier 2 Calculation Methodology**. Section 2.20 provides more information about reporting GHG emissions from the combustion of tires.

- May be used for the combustion of fuel listed in Table 2-5, *Default CO_2 Emission Factors and High Heat Values*, if the combustion unit has a maximum rated heat input capacity greater than 250 MMBtu/hr (or in the scenario that a group of units is served by a common supply pipe, and at least one unit has a maximum rated heat input capacity greater than 250 MMBtu/hr). In order to use Tier 1 for a unit with a maximum rated heat input capacity greater than 250 MMBtu/hr, Tier 4 calculation methodology must <u>not</u> be required *and* the fuel provides less than 10 percent of the annual heat input to the unit or to the group of units served by a common supply pipe.

2.14.3 Tier 1 CO_2 Emissions Calculation

Annual CO_2 emissions may be calculated in one of two ways when Tier 1 Methodology is applicable. The difference between the two approaches is that one method is used when natural gas billing records are used to quantify fuel usage and the other is for all other instances.

2.14.3.1 Tier 1 CO_2 Emissions (Fuel Usage <u>is not</u> from Billing Records)

In most instances, CO2 emissions are calculated using Equation 2-4 as follows:

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation 2-4

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric ton/yr)
Fuel	=	Mass or volume of fuel combusted per year, from company records (short ton/yr for solid fuel, ft^3/yr for gaseous fuel, or gal/yr for liquid fuel)
HHV	=	Default HHV of the fuel, from Table 2-5 (MMBtu/mass or MMBtu/volume, as applicable)
EF	=	Fuel-specific default CO_2 emission factor, from Table 2-5 (kg CO_2/MMBtu)
1×10^{-3}	=	Conversion factor from kilograms to metric tons (metric ton/kg)

2.14.3.2 Tier 1 CO_2 Emissions (Fuel Usage <u>is</u> from Billing Records)

Use Equation 2-5 to calculate CO_2 emissions from the combustion of natural gas when the natural gas billing records are used to quantify fuel usage and gas consumption. **If the records are**

expressed in units of therms, multiply the usage/consumption value by 0.1 to convert it to MMBtu:

$$CO_2 = 1 \times 10^{-3} \times Gas \times EF$$

Equation 2-5

Where:

CO_2 = Annual CO_2 mass emissions from natural gas combustion (metric ton/yr)
Gas = Annual natural gas usage, from billing records (MMBtu/yr)
EF = CO_2 emission factor for natural gas, from Table 2-5 (kg CO_2/MMBtu)
1×10^{-3} = Conversion factor from kilograms to metric tons (metric ton/kg)

2.14.4 Tier 1 CH_4 and N_2O Emissions Calculations

Annual CH_4 and N_2O emissions must be calculated and reported for units required to report CO_2 emissions and only for those fuels that are listed in Table 2-6. When multiple fuels are combusted during the reporting year, sum the fuel-specific results from the applicable equations to obtain the total annual CH_4 and N_2O emissions, in metric tons. Refer to Section 2.18 for more information on fuel blends. As with Tier 1 CO_2 emissions estimations, there are two methods for calculating CH_4 and N_2O emissions - one method is used when natural gas billing records are used to quantify fuel usage and the other is for all other instances.

2.14.5 Tier 1 CH_4 and N_2O Emissions Calculations

Annual CH_4 and N_2O emissions must be calculated and reported for units required to report CO_2 emissions and only for those fuels that are listed in Table 2-6. When multiple fuels are combusted during the reporting year, sum the fuel-specific results from the applicable equations to obtain the total annual CH_4 and N_2O emissions, in metric tons. Refer to Section 2.18 for more information on fuel blends. As with Tier 1 CO_2 emissions estimations, there are two methods for calculating CH_4 and N_2O emissions - one method is used when natural gas billing records are used to quantify fuel usage and the other is for all other instances.

2.14.5.1 Tier 1 CH_4 and N_2O Emissions (Fuel Usage is not from Billing Records)

Use Equation 2-6 for Tier 1 CH_4 and N_2O emissions calculations except when natural gas usage is in units of therms or MMBtu is obtained from gas billing records.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation 2-6

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric ton/year)

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass/yr or volume/year)
HHV = Default HHV of the fuel from Table 2-5 (MMBtu/mass or MMBtu/volume as applicable)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table 2-6 (kg CH_4 or N_2O per MMBtu)
$\mathbf{1 \times 10^{-3}}$ = Conversion factor from kilograms to metric tons (metric ton/kg)

2.14.5.2 Tier 1 CH_4 and N_2O Emissions (Fuel Usage from Billing Records)

Use **Equation** to calculate CH_4 and N_2O emissions when natural gas usage is obtained from gas billing records. **If the records are expressed in units of therms, multiply the usage/consumption value by 0.1 to convert it to MMBtu**.

$$CH_4\ or\ N_2O = 1\times10^{-3}\times Fuel\times EF$$

Equation 2-7

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas (metric ton/yr)
Fuel = Annual natural gas usage, from gas billing records (MMBtu)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table 2-6 (kg CH_4 or N_2O per MMBtu)
$\mathbf{1 \times 10^{-3}}$ = Conversion factor from kilograms to metric tons (metric ton/kg)

2.15 Tier 2 Calculation Methodology

Tier 2 utilizes default emission factor values and derived HHV in GHG emissions calculations. In cases where the fuel HHV is routinely sampled and analyzed by the facility or the facility gets these values from the fuel supplier at a frequency as specified in Chapter 2.21, Tier 2 shall be used.

2.15.1 Tier 2 Applicability

The following requirements, conditions, and/or restrictions should be used to evaluate if application of Tier 2 for CO_2 emissions calculations for a facility is applicable:

- May be used for the combustion of any type of fuel in a unit with a maximum rated input heat capacity of 250 MMBtu/hr or less provided that the fuel is listed in Table 2-5.

- May be used in a unit with a maximum rated heat input capacity greater than 250 MMBtu/hr for the combustion of natural gas and/or distillate fuel oil.

- May be used for MSW in a unit of any size that produces steam, if Tier 4 calculation methodology is not required.

2.15.2 Tier 2 CO_2 Emissions Calculations

40 CFR 98 Subpart C offers several approaches to the calculation of CO_2 emissions based on the fuel combusted. Specifically, Tier 2 outlines the process of calculating CO_2 emissions for units that burn MSW, blended fuels, and all other fuels listed in Table 2-5. These procedures are described below:

2.15.2.1 Tier 2 CO_2 Emissions from Unblended Fuels, Excluding MSW

For most unblended fuels from Table 2-5 (other than MSW), **CO_2 emissions are still calculated using Equation 2-4.** However, Tier 2 requires that the HHV be calculated and used in place if the default fuel HHV. Calculation of the HHV is based on the frequency of fuel sampling analysis. For each unit with a maximum rated heat input capacity greater than or equal to 100 MMBtu/hr (or for a group of units that includes at least one unit of that size), the annual average HHV (when fuel sampling analysis is performed at a frequency of once a month) is calculated using Equation 2-8. If multiple HHV are determined in a single month, the values should be averaged arithmetically.

$$(\boldsymbol{HHV})_{\boldsymbol{annual}} = \frac{\sum_{i=1}^{n}(\boldsymbol{HHV})_i \times (\boldsymbol{Fuel})_i}{\sum_{i=1}^{n}(\boldsymbol{Fuel})_i}$$

Equation 2-8

Where:

$(HHV)_{annual}$ = Weighted annual average HHV of the fuel (MMBtu/mass or MMBtu/volume)

$(HHV)_i$ = Measured HHV of the fuel, for month “i” (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (MMBtu/mass or MMBtu/volume)

$(Fuel)_i$ = Mass or volume of the fuel combusted during month “i,” from company records (short ton/yr for solid fuel, ft^3/yr for gaseous fuel, or gal/yr for liquid fuel)

n = Number of months in the year that the fuel is burned in the unit

For facilities who receive/perform fuel sampling analysis less frequently than monthly, or for a unit with a maximum rated heat input capacity less than 100 MMBtu/hr (or group of such units) regardless of the sampling frequency, the annual average HHV must use Equation 2-8 or the arithmetic average of HHV for all values for the year. This includes valid and substitute data, a topic discussed further in this guide.

2.15.2.2 Tier 2 CO_2 Emissions from MSW Combustion

For units that combust MSW and produce steam, CO_2 emissions using Tier 2 methodology are calculated using Equation 2-9. This equation may also be used for other solid fuels listed in Table 2-5 as long as steam is generated by the unit.

$$CO_2 = 1 \times 10^{-3} \times Steam \times B \times EF$$

Equation 2-9

Where:

CO_2 = Annual CO_2 mass emissions from MSW or solid fuel combustion (metric ton/yr)

Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam/yr)

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (MMBtu/lb steam)

EF = Fuel-specific default CO_2 emission factor, from Table 2-5 (kg CO_2/MMBtu)

1×10^{-3} = Conversion factor from kilograms to metric tons (metric ton/kg)

2.15.2.3 Tier 2 CO_2 Emissions from Fuel Blends

If fuels that are meant to be blended for combustion are received separately and are quantified, calculate the mass CO_2 emissions separately for each fuel component. Fuels that are pre-mixed or mixed on-site without exact quantification of the amount of each component in the fuel require the reasonable estimation of the relative proportions of the blend to determine appropriate HHV and CO_2 emission factor values. In these instances, consider the blended fuel to be a fuel "type" and measure its HHV at the frequency prescribed. Fuel sampling must be performed weekly for blends of solid fuels (except MSW) to form a composite sample, which is analyzed monthly. Liquid or gaseous fuel blends are required to be sampled and analyzed at least once per calendar quarter. More frequent sampling and analysis is recommended if the fuel blend varies significantly during the year. A heat-weighted CO_2 emission factor must be calculated for the blend. Equation 2-10 uses default HHV (from Table 2-5) and the estimated mass or volume percentages of the components of the blend as shown:

$$(EF)_B = \frac{\sum_{i=1}^{n}[(HHV)_i(\%\,Fuel)_i(EF)_i]}{(HHV)_{annual,B}}$$

Equation 2-10

Where:

$(EF)_B$ = Heat-weighted CO_2 emission factor for the blend (kg CO_2/MMBtu)

$(HHV)_i$ = Default HHV for fuel "i" in the blend, from Table 2-5 (MMBtu/mass or MMBtu/volume)

$(\%Fuel)_i$ = Estimated mass or volume percentage of fuel "i" (mass % or volume %, as applicable, expressed as a decimal fraction; e.g., 25% = 0.25)

$(EF)_i$ = Default CO_2 emission factor for fuel "i" from Table 2-5 (MMBtu/mass or MMBtu/volume)
$(HHV)_{annual,B}$ = Annual average HHV for the blend, calculated according to 40 CFR 98.33(a)(2)(ii), Equation . (MMBtu per mass or volume)

The annual CO_2 mass emissions from the combustion of a fuel blend is determined by substituting the above calculated values into Equation 2-4.

If the quantities of individual fuels blended for combustion are known, the CO_2 mass emissions are calculated separately. Use the total measured mass or volume of a fuel component with its appropriate default CO_2 emission factor from Table 2-5 and the annual HHV (as calculated using Equation 2-8) in Equation 2-4 to calculate the CO_2 mass emissions for a component of the blended fuel.

If fuel sampling and analysis to derive HHV is not performed at the minimum frequency prescribed and if the unit qualifies to use Tier 1 calculations, a heat-weighted default high heat value $[(HHV)^*_B]$ can be calculated using Equation 2-11. This value can be used to replace the $(HHV)annual,_B$ parameter to determine the heat-weighted CO_2 emission factor for the blend.

$$\boldsymbol{HHV_B^*} = \sum_{\boldsymbol{i=1}}^{\boldsymbol{n}} [(\boldsymbol{HHV})_{\boldsymbol{i}} \times (\%\boldsymbol{Fuel})_{\boldsymbol{i}}]$$

Equation 2-11

Where:

HHV_B* = Heat-weighted default HHV for the blend (MMBtu/mass or MMBtu/volume)
(HHV)i = Default HHV for fuel "i" in the blend, from Table 2-5 (MMBtu/mass or MMBtu/volume)
(%Fuel)i = Estimated mass or volume percentage of fuel "i" in the blend (mass % or volume %, as applicable, expressed as a decimal fraction)

Substituting this value into Equation 2-4, in addition to the calculated emission factor of the blend, yields the heat-weighted CO_2 emission factor for the blend.

In the event that a fuel blend consists of fuels that are included Table 2-5 and some that are not, calculate the CO_2 and other GHG emissions only for the fuels listed in Table 2-5 using the best available estimate of the mass or volume percentages of those fuels in the blend. The procedure for calculating mass CO_2 emissions from blends using fuels not in Table 2-5 involves modifying Equation 2-4 and Equation 2-7. For each fuel listed in Table 2-5, $(\% \text{ Fuel})_i$ will apply to only those fuels by estimating the mass or volume percentage of the fuel in the blend divided by the sum of the mass or volume percentages of the fuels. Equation 2-4 can be modified by using the "Fuel" term to represent the total mass or volume of the blended fuel combusted during the year multiplied by the sum of the mass or volume percentages of the Table 2-5 fuels in the blend. These procedures are discussed in 40 CFR 98.34 (a)(3)(iv).

2.15.3 Tier 2 CH_4 and N_2O Emissions Calculations

Annual CH_4 and N_2O emissions must be calculated and reported for units required to report CO_2 emissions and only for those fuels that are listed in Table 2-5. There are two equations for the calculation of CH_4 and N_2O – one applicable to units that produce steam, and the other applicable to those units which do not. When multiple fuels are combusted during the reporting year, sum the fuel-specific results from the applicable equations to obtain the total annual CH_4 and N_2O emissions, in metric tons. Refer to Section 2.18 for more information on fuel blends.

2.15.3.1 Tier 2 CH_4 and N_2O Emissions from Units that do not Produce Steam

If Equation 2-4 was used to calculate CO_2 emissions, use Equation 2-6 to calculate CH_4 and N_2O emissions using the same fuel and HHV values used in Equation 2-4.

2.15.3.2 Tier 2 CH4 and N2O Emissions from Units that Produce Steam

$$\boldsymbol{CH_4 \ or \ N_2O = 1 \times 10^{-3} \times HHV \times EF \times Fuel}$$

Equation 2-12

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric ton/year)

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass/yr or volume/year)

HHV = Default high heat value of the fuel from Table 2-5 (MMBtu/mass or MMBtu/volume as applicable)

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table 2-6 (kg CH_4 or N_2O per MMBtu)

1×10^{-3} = Conversion factor from kilograms to metric tons (metric ton/kg)

The second equation sanctioned for use with Tier 2 CH_4 and N_2O emissions calculations is for units that use any fuel and produce steam. If Equation 2-9 was used to calculate CO_2, it may be employed to calculate CH_4 and N_2O using the same values for steam and the ratio of the unit's maximum rated heat input capacity as shown:

$$\boldsymbol{CO_2 = 1 \times 10^{-3} \times Steam \times B \times EF}$$

Equation 2-13

Where:

CO_2 = Annual CO_2 mass emissions from MSW or solid fuel combustion (metric ton/yr)

Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam/yr)
B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (MMBtu/lb steam)
EF = Fuel-specific default CO_2 emission factor, from Table 2-6 (kg/MMBtu)
1×10^{-3} = Conversion factor from kilograms to metric tons (metric ton/kg)

2.16 Tier 3 Calculation Methodology

Tier 3 CO_2 emissions calculations are based on the annual average carbon content of the fuel and use molecular weights ratio. This approach is used primarily when the other methods cannot be employed.

2.16.1 Tier 3 Applicability

The following requirements, conditions, and/or restrictions should be used to evaluate the appropriateness of utilizing Tier 3 for CO_2 emissions calculations for a facility:

- May be used for a unit of any size that combusts any type of fuel listed in Table 2-5 (except MSW), unless Tier 4 is required.

- Must be used for a unit with a maximum rated heat input capacity greater than 250 MMBtu/hr that combusts any type of fuel listed in Table 2-5 (except MSW) unless either of the following conditions apply:
  - The use of Tier 1 or 2 is permitted
  - Tier 4 Calculation Methodology is required

- Tier 3 must be used for a fuel not listed in Table 2-5 if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 MMBtu/hr (or is in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 MMBtu/hr), provided that both of the following conditions apply:
  - Tier 4 is not required
  - The fuel provides 10 percent or more of the annual heat input to the unit or to the group of units served by a common supply pipe.

2.16.2 Tier 3 CO_2 Emissions Calculations

The annual CO_2 mass emissions must be calculated for each fuel type. There are three equations that can be used to calculate CO_2 emissions via Tier 3 based on the phase (solid, liquid, gas) of the fuel.

2.16.2.1 Tier 3 CO_2 Emissions from the Combustion of Solid Fuels

For solid fuels, use Equation 2-14:

$$CO_2 = \left(\frac{44}{12}\right) \times Fuel \times CC \times 0.91$$

Equation 2-14

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric ton/yr)

Fuel = Annual mass of the solid fuel combusted, from company records (short ton/yr)

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content is determined using the same procedures as specified for HHV, Equation 2-8

44/12 = Ratio of molecular weights, CO_2 to carbon

0.91 = Conversion factor from short tons to metric tons (metric tons/short ton)

2.16.2.2 Tier 3 CO_2 Emissions from the Combustion of Liquid Fuels

For liquid fuels, use Equation 2-15:

$$CO_2 = \left(\frac{44}{12}\right) \times Fuel \times CC \times 0.001$$

Equation 2-15

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric ton/yr)

Fuel = Annual mass of the solid fuel combusted, from company records (gal/yr). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 CFR 98.3(i)

CC = Annual average carbon content of the liquid fuel (kg Carbon per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV, Equation 2-8

44/12 = Ratio of molecular weights, CO_2 to carbon

0.001 = Conversion factor from kg to metric tons (metric tons/kg)

2.16.2.3 Tier 3 CO_2 Emissions from the Combustion of Gaseous Fuels

For gaseous fuels, use Equation 2-16:

$$CO_2 = \left(\frac{44}{12}\right) \times Fuel \times CC \times \left(\frac{MW}{MVC}\right) \times 0.001$$

Equation 2-16

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific gaseous fuel (metric ton/yr)

Fuel = Annual mass of the solid fuel combusted (scf/yr). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose

CC = Annual average carbon content of the gaseous fuel (kg Carbon per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV, Equation 2-8

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV, Equation 2-8

MVC = Molar volume conversion factor at standard conditions, as defined in 40 CFR 98.6. Use **849.5** scf/kg mole if you select 68 °F as standard temperature and **836.6** scf/kg mole if you select 60 °F as standard temperature.

44/12 = Ratio of molecular weights, CO_2 to carbon

0.001 = Conversion factor from kg to metric tons (metric ton/kg)

Note: A routine fuel sample analysis should contain information regarding fuel-specific carbon content, density, and HHV. In addition, if the volumetric flow rate is unknown and the only information available is mass, a volumetric flow rate can be calculated using the fuel density. Refer to 40 CFR 98.33 for appropriate procedures using fuel density.

2.16.2.4 Tier 3 Calculations for CO_2 Emissions from Fuel Blends

As with unblended fuels, it is necessary to calculate mass CO_2 emissions from blended fuels. These calculations apply to blends of fuel that are in the same state of matter. If the carbon content and/or molecular weight of each component of a fuel blend is accurately measured prior to blending, it is appropriate to use Equation 2-14, Equation 2-15, and Equation 2-16. If the fuel is already blended, consider the blended fuel to be a fuel type in and of itself. At the specified frequency, measure the carbon content and/or the molecular weight of the blend and calculate the annual average of each parameter as described in 40 CFR 98.33(a)(2)(ii). In addition, measure the mass or volume of the blended fuel combusted during the reporting year. Substitute these values into Equation 2-14, Equation 2-15, and Equation 2-16 to calculate the mass CO_2 emissions from the combustion of blended fuels for units using Tier 3 methodology.

2.16.3 Tier 3 CH_4 and N_2O Emissions Calculations

Annual CH_4 and N_2O emissions must be calculated and reported for units required to report CO_2 emissions, but only for those fuels that are listed in Table 2-6. CH_4 and N_2O emissions for Tier 3 are calculated in the same manner as CH_4 and N_2O emissions for Tier 1. Use Equation 2-6 except when natural gas usage is in units of therms or MMBtu is obtained from gas billing records. In those instances, use Equation 2-7, but note that if the records are expressed in units of therms, multiply the usage/consumption value by 0.1 to convert it to MMBtu. When multiple fuels are combusted during the reporting year, sum the fuel-specific results from the applicable equations to obtain the total annual CH_4 and N_2O emissions, in metric tons. Refer to Section 2.18 for more information on fuel blends and CH_4 and N_2O emissions.

2.17 Tier 4 Calculation Methodology

Tier 4 is the most parameter specific calculation methodology. It uses quality-assured data from CEMS to calculate annual CO_2 emissions.

2.17.1 Tier 4 Applicability

Use the following scenarios to determine if Tier 4 methodology is appropriate:

Scenario 1: This scenario applies to individual units or when two or more stationary fuel combustion units are vented through a monitored common stack or duct and at least one of those units meets all of the following conditions:

- The unit has a maximum rated heat input capacity greater than 250 MMBtu/hr or the unit combusts MSW and has a maximum rated input capacity greater than 600 tons per day of MSW.
- The unit combusts solid fossil fuel or MSW as the primary fuel.
- The unit has operated for more than 1,000 hours in any calendar year since 2005.
- The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.
- The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of 40 CFR 75, 40 CFR 60 or an applicable State continuous monitoring program.
- The installed gas or stack gas volumetric flow rate monitors are required to undergo periodic quality assurance testing in accordance to either Appendix B to 40 CFR 75 or Appendix F to 40 CFR 60, or an applicable State continuous monitoring program.

Scenario 2: This scenario applies to individual units or when two or more stationary fuel combustion units are vented through a monitored common stack or duct and at least one of those units meets all of the following conditions:

- The unit has a maximum rated heat input capacity of 250 MMBtu/hr or less or the unit combusts MSW with a maximum rated heat input capacity of 600 tons of MSW per day or less.

- The unit has both a stack gas volumetric flow rate monitor **and** a CO_2 concentration monitor.

- The unit combusts solid fossil fuel or MSW as the primary fuel.

- The unit has operated for more than 1,000 hours in any calendar year since 2005.

- The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

- The installed CEMS include a CO_2 monitor and a stack gas volumetric flow rate monitor, and the monitors have been certified in accordance with either the requirements of 40 CFR 75, 40 CFR 60 or an applicable State continuous monitoring program.

- The installed CO_2 and stack gas volumetric flow rate monitors are required to undergo periodic quality assurance testing in accordance to either Appendix B to 40 CFR 75 or Appendix F to 40 CFR 60, or an applicable State continuous monitoring program.

Additionally, Tier 4 Calculation Methodology must be used for a unit that is required to report CO_2 mass emissions if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by January 1, 2010. If a change occurs that triggers Tier 4 Calculation Methodology, Tier 4 must be used no later than 180 days following the date of the change (for example, the installation of continuous monitoring equipment). Tier 4 can be used for a unit of any size combusting any type of fuel, as well as for groups of stationary combustion units served by a common supply pipe.

2.17.2 Tier 4 CO_2 Emissions Calculations

The annual CO_2 mass emissions must be calculated for each fuel type. If both biomass and fossil fuels are combusted during the year, the biogenic CO_2 emissions must be determined and reported separately. CO_2 emissions from all fuels combusted in a unit using CEMS must be calculated using Tier 4 calculation methodology using the CEMS data. This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor. In some situations, an O_2 concentration monitor may be used in place of a CO_2 concentration monitor to determine hourly CO_2 concentrations. Refer to 40 CFR 98.33 (a)(4)(iv) for further instruction on this substitution.

There may be instances where a combustion unit has a portion of the generated flue gas diverted from the main flue gas exhaust system for purposes such as heat recovery. In such cases, if the stationary combustion unit is subject to Tier 4, but the diverted gas is exhausted through a stack not equipped with CEM equipment to measure CO_2 mass emissions, refer to 40 CFR 98.33(a)(4)(viii) for information regarding accurate CO_2 emissions calculation.

There are two equations that can be used for CO_2 calculations; the difference between the two is if the CO_2 concentration is measured on a wet basis or measured on a dry basis and corrected for moisture. Both equations provide an hourly CO_2 emission rate expressed in metric tons per hour. **To obtain the total CO_2 emissions in metric tons, multiply the following CO_2 emission rates by the operating time, in hours.** The operating time is only the time during which fuel is combusted. For common stack configurations, the operating time is the time during which effluent gases flow through the common stack. The hourly mass emissions (converted to metric tons) are summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

2.17.2.1 Tier 4 CO_2 Emissions if CO_2 Monitor Measures on a Wet Basis

Use Equation 2-17 to calculate hourly CO_2 concentration when the CO_2 monitor measures on a wet basis.

$$\boldsymbol{CO_2 = 5.18 \times 10^{-7} \times C_{CO_2} \times Q}$$

Equation 2-17

Where:

CO_2	=	CO_2 mass emission rate (metric ton/hr)
C_{CO2}	=	Hourly average CO_2 concentration (% CO_2)
Q	=	Hourly average stack gas volumetric flow rate (scfh)
5.18×10^{-7}	=	Conversion factor (metric tons/scf/% CO_2)

2.17.2.2 Tier 4 CO_2 Emissions if CO_2 Monitor Measures on a Dry Basis

If the CO_2 monitor measures on a dry basis, corrections for the stack gas moisture content are needed because the flow monitor measures on a wet basis. In this instance, calculate CO_2 emissions as shown in Equation 2-18.

$$CO_2^* = CO_2 \times \left(\frac{100 - \%H_2O}{100}\right)$$

Equation 2-18

Where:

CO_2* = Hourly CO_2 mass emission rate, corrected for moisture (metric ton/hr)
CO_2 = Hourly CO_2 mass emission rate from Equation 2-17 (metric ton/hr)
$\%H_2O$ = Hourly moisture percentage in the stack gas (measured or default value, as appropriate)

There are several options to determine the moisture percentage value for the above equation. In order to decide which procedure is the most appropriate for a specific facility, refer to 40 CFR 98.33 (a)(4)(iii) for additional information.

2.17.3 Tier 4 CH_4 and N_2O Emissions Calculations

Annual CH_4 and N_2O emissions must be calculated and reported for units required to report CO_2 emissions and only for those fuels that are listed in Table 2-6. For unit's subject to Tier 4, calculate CH_4 and/or N_2O using the following equation:

$$CH_4 \ or \ N_2O = 1 \times 10^{-3} \times (HI)_A \times EF$$

Equation 2-19

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric ton/yr)
$(HI)_A$ = Cumulative annual heat input from combustion of the fuel (MMBtu/yr)
EF = Fuel-specific emission factor for CH_4 or N_2O, from Table 2-6 (kg/MMBtu)
1×10^{-3} = Conversion factor from kg to metric tons (metric ton/kg)

It is appropriate to use best available information (*e.g.* fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the cumulative annual heat input from combustion of that fuel or electronic data reports made for units subject to 40 CFR 75. If more than one type of fuel listed in Table 2-6 is combusted during the reporting year, use Equation 2-19 for each type of fuel. Sum the fuel-specific emissions to obtain the total annual CH_4 and N_2O emissions, in metric tons.

2.18 CH_4 and N_2O Emission Calculation Procedures for Blended Fuels

When calculating annual CH_4 and N_2O emissions for units that combusted multiple fuels, use the appropriate equations for each fuel and sum them together. The appropriate equation is determined by using the CH_4/N_2O equation for the tier calculation methodology being used. For blends that are mixed and combusted without prior measurements, a reasonable estimate of the percentage composition of the blend is required. Multiply the estimated fuel percentage of the specific fuel component by the total annual mass or volume of the blended fuel combusted during the reporting year. The resulting value is the estimate of the annual consumption of that particular fuel. Multiply this value by the HHV of the fuel (or default value or the measured annual average value) to get an estimate of the annual heat input from that specific fuel. Use the appropriate equation to calculate CH_4 and N_2O annual emissions for this fuel according to the Tier calculation method required. Finally, sum the values for all fuel components of the blend to obtain annual emissions for the blend.

2.19 Additional Calculation Methodologies

This section discusses alternative calculation methods for certain units' subject to 40 CFR 75 reporting requirements, CO_2 emissions from sorbent, and biogenic CO_2 emissions from combustion of biomass with other fuels.

2.19.1 Alternative Methods for Certain Units Subject to 40 CFR 75

Stationary combustion units that do not fall in to the Electricity Generation source category (under 40 CFR 98 Subpart D) and that report data to the EPA according to the requirements of 40 CFR 75 may qualify to use any of the following methods in lieu of using any of the four calculation methodology tiers. In other words, as an alternative to any of the four tier calculation methodologies, units that report to EPA year-round heat input data under 40 CFR Part 75 can calculate annual CO_2 emissions using Part 75 methods.

2.19.1.1 Units Described in 40 CFR 98.33 (a)(5)(i)

For a unit that combusts only natural gas and/or fuel oil, does not fall into the Electricity Generation source category, and monitors and reports heat input data year-round according to Appendix D of 40 CFR 75, yet is not required by the applicable 40 CFR 75 program to report CO_2 mass emissions data, annual CO_2 mass emissions may be calculated as follows:

Use the hourly heat input data from Appendix D of 40 CFR 75 in conjunction with the following equation to determine the hourly CO_2 mass emission rates in tons per hour.

$$\boldsymbol{W_{CO_2} = \left(\frac{F_c \times H \times U_f \times MW_{CO_2}}{2000}\right)}$$

Equation 2-20

Where:

W_{CO_2} = CO_2 emitted from combustion (ton/hr)

MW_{CO_2} = Molecular weight of carbon dioxide (**44.0 lb/lb-mole)**

F_c = Carbon based F-factor, **1040 scf/MMBtu for natural gas; 1,420 scf/MMBtu for crude, residual, or distillate oil**; and calculated according to the procedures in section 3.3.5 of Appendix F 40 CFR 75 for other gaseous fuels (scf/MMBtu)

H = Hourly heat input in MMBtu, as calculated using the procedures in section 5 of Appendix F 40 CFR 75 (MMBtu/hr)

U_f = **1/385 scf CO_2/lb-mole** at 14.7 psia and 68 °F

2000 = Factor converting pounds to tons (lb/ton)

Multiply the hourly CO_2 hourly emissions by the operating time and sum for the year to calculate the annual CO_2 mass emissions in tons per year. Divide by 1.1 to convert this value to metric tons.

2.19.1.2 Units Described in 40 CFR 98.33 (a)(5)(ii)

For a unit that combusts only natural gas and/or fuel oil, does not fall into the Electricity Generating source category, monitors and reports input data year-round according to 40 CFR 75.19, yet is not required by an applicable Part 75 program to report CO_2 mass emissions data, annual CO_2 mass emissions are calculated as follows:

$$W\,CO_2 = EF\,CO_2 \times HI_{hr}$$

Equation 2-21

Where:

WCO_2 = Hourly CO_2 mass emissions (ton/hr)

$EFCO_2$ = Either the fuel-based CO_2 emission factor (**0.059 for natural gas or 0.091 for oil**) <u>or</u> the fuel-and-unit-specific CO_2 emission rate from paragraph (c)(1)(iii) of 40 CFR 75.19 (ton/MMBtu)

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of 40 CFR 75.19 <u>or</u> the hourly heat input as determined under paragraph (c)(3)(ii) of 40 CFR 75.19 (MMBtu/hr).

Multiply the hourly CO_2 hourly emissions by the operating time and sum for the year to calculate the annual CO_2 mass emissions in tons per year. Divide by 1.1 to convert this value to metric tons.

2.19.1.3 Units Described in 40 CFR 98.33 (a)(5)(iii)

For a unit that is not in the Electricity Generating source category, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to 40 CFR 75, yet is not required under Part 75 to report CO_2 mass emissions data, annual CO_2 mass emissions are calculated as follows:

<u>For CO_2 emissions measured on a wet basis</u>:

$$E_h = K \times C_h \times Q_h$$

Equation 2-22

Where:

E_h = Hourly CO_2 mass emission rate during unit operation (ton/hr)

K = **5.7×10^{-7} for CO_2** (ton/scf $\%CO_2$)
C_h = Hourly average CO_2 concentration during unit operation, wet basis, measured directly with a CO_2 monitor ($\%CO_2$)
Q_h = Hourly average volumetric flow rate during unit operation, wet basis (scf/hr)

For CO_2 emissions measured on a dry basis:

$$E_h = K \times C_{hp} \times Q_{hs} \times \frac{(100 - \%H_2O)}{100}$$

Equation 2-23

Where:

E_h = Hourly CO_2 mass emission rate (ton/hr)
K = **5.7×10^{-7} for CO_2** (ton/scf $\%CO_2$)
C_{hp} = Hourly average CO_2 concentration in flue, dry basis ($\%CO_2$)
Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, (scf/hr)

Multiply the hourly CO_2 hourly emissions by the operating time and sum for the year to calculate the annual CO_2 mass emissions in tons per year. Divide by 1.1 to convert this value to metric tons. Note that data from O_2 monitors may be used to calculate CO_2 emissions when a facility lacks CO_2 monitors. In these instances, the hourly average O_2 readings may be converted to CO_2 using Equation F-14a or Equation F-14b of Appendix F in 40 CFR 75 as applicable before applying Equation 2-22 or Equation 2-23.

2.19.2 Calculation of CO_2 from Sorbent (Units Without CEMS)

When a unit is a fluidized bed boiler equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection to remove acid gases, and the chemical reaction between the acid gas and the sorbent produces CO_2 emissions, use Equation 2-24 to calculate the CO_2 emissions from the sorbent, except when those CO_2 emissions are monitored by CEMS. **The total annual emissions reported for the MRR shall include the CO_2 emissions from fuel combustion and the sorbent produced CO_2 emissions**.

$$CO_2 = 0.91 \times S \times R \times \left(\frac{MW_{CO_2}}{MW_S}\right)$$

Equation 2-24

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric ton/yr)
S = Limestone or other sorbent used in the reporting year, from company records (short ton/yr)
R = The number of moles of CO_2 released upon capture of one mole of the acid gas species being removed (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2)

MW_{CO2} = Molecular weight of carbon dioxide (**44 lb/lb-mol**)
MW_S = Molecular weight of sorbent, **100 if calcium carbonate** (lb/lb-mol)
0.91 = Conversion factor from short tons to metric tons (metric ton/ton)

Note that when a sorbent other than calcium carbonate ($CaCO_3$) is used, determine site-specific values of R and MW_S.

2.19.3 Biogenic CO_2 Emissions from Combustion of Biomass with other Fuels

Separate biogenic CO_2 emissions reporting is required for biomass fuels listed Table 2-5 when a unit combusts a combination of those biomass fuels and fossil fuels. Separate reporting of biogenic CO_2 emissions reporting is also required for the combustion of MSW. Separate calculation and reporting of biogenic CO_2 emissions is not required when tires are combusted.

If a biomass fuel not listed in Table 2-5 is combusted in a unit that does not use CEMS to quantify its CO_2 mass emissions and has a maximum heat input capacity greater than 250 MMBtu/hr, and the biomass fuel accounts for 10 percent or more of the annual heat input capacity, Tier 3 must be used to determine the carbon content of the biomass fuel and for calculating the biogenic CO_2 emissions for reporting. When reporting biogenic CO_2 emissions, use the following calculation procedures

If a facility combusts any biomass fuel listed in Table 2-5 does not combust MSW or tires, uses any size unit that may or may not have CO_2 CEMS, and Tier 2 is not required, use Equation 2-4 to calculate annual CO_2 emissions from biomass combustion.

The biomass combusted may be determined using company records, best information available, or with the following equation:

$$(Fuel)_p = \frac{(H \times S) - (HI)_{nb}}{2000 \times (HHV)_{bio} \times (Eff)_{bio}}$$

Equation 2-25

Where:

$(Fuel)_p$ = Quantity of biomass consumed during the measurement period "p" (ton/period)
H = Average enthalpy of the boiler steam during the measurement period (Btu/lb)
S = Total boiler steam production for the measurement period (lb/period)
$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/period)
$(HHV)_{bio}$ = Default or measured HHV of the biomass fuel (Btu/lb)
$(Eff)_{bio}$ = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction
2000 = Factor converting pounds to tons (lb/ton)

If a facility uses a stationary fuel combustion unit that has a CO_2 (or surrogate O_2) monitor and a stack gas flow rate monitor to calculate annual CO_2 mass emissions, does not combust MSW or tires, and the CO_2 emissions are only from combusted products (no sorbent or process emissions), biogenic emissions can be calculated using the following process. First, the volume of CO_2 emitted per operating hour is calculated using the following equation:

$$V_{CO_2h} = \frac{(\%CO_2)_h}{100} \times Q_h \times t_h$$

Equation 2-26

Where:

V_{CO2h} = Hourly volume of CO_2 emitted (scf)
$(\%CO_2)_h$ = Hourly average CO_2 concentration, measured by the CO_2 concentration monitor, or, if applicable, calculated from the hourly average O_2 concentration ($\%CO_2$)
Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scf/hr)
t_h = Source operating time (hr)
100 = Conversion factor from percent to a decimal fraction (%)

Sum the results from Equation 2-26 for the reporting year to determine the total annual volume of CO_2 emitted (V_{total}). Next, use the following equation to quantify the annual volume of CO_2 emitted from fossil fuel combustion:

$$V_{ff} = \frac{Fuel \times F_c \times HHV}{10^6}$$

Equation 2-27

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf/yr)
Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in 40 CFR 98.6 (lb/yr for solid fuel, gal/yr for liquid fuel, and scf/yr for gaseous fuel)
F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR 75, or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR 75 (scf CO_2/MMBtu)
HHV = High heat value of the fossil fuel, from fuel sampling and analysis (Btu/lb for solid fuel, Btu/gal for liquid fuel, and Btu/scf for gaseous fuel), sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in 40 CFR 98.34(a)(2). The average HHV shall be calculated according to 40 CFR 98.33(a)(2)(ii)
10^6 = Factor converting Btu to MMBtu (Btu/MMBtu)

The annual volume of CO_2 from the combustion of biomass is determined by subtracting the result of Equation 2-27 (V_{ff}) from the total annual volume of CO_2 emitted (V_{total}). Divide the annual volume of CO_2 emissions from biomass by the total annual volume of CO_2 emissions to determine the biogenic percentage of the annual CO_2 emissions expressed as a decimal fraction as shown in the following equation:

$$\%\,\boldsymbol{Biogenic} = \frac{\boldsymbol{V_{bio}}}{\boldsymbol{V_{total}}}$$

Equation 2-28

Where,

%Biogenic	=	Fraction of the volume of CO_2 emitted from biogenic sources
$\mathbf{V_{bio}}$	=	Volume of CO_2 emitted from biogenic sources (scf/yr)
$\mathbf{V_{total}}$	=	Volume of CO_2 emitted from all sources (scf/yr)

Next, multiply the biogenic CO_2 volume fraction (%Biogenic) from Equation 2-28 by the annual CO_2 emissions in metric tons to calculate the annual biogenic CO_2 mass emissions. The annual CO_2 emissions used in this calculation are determined either using Tier 4 calculation methodology [40 CFR 98.33 (a)(4)(iv)], alternative calculation methodology [40 CFR 98.33 (a)(5)(iii)(B)], or an electronic data report required under 40 CFR 75.

If a facility has units that combust MSW, annual CO_2 biogenic emissions can be determined by using proportions of biogenic and non-biogenic emissions in the flue gas. This procedure can be used for any unit that co-fires biomass and fossil fuels including units equipped with CO_2 CEMS. First, calculate the total annual CO_2 emissions for the unit using the appropriate methodology. Next, the relative proportions of biogenic and non-biogenic CO_2 emission in the flue gas are determined on a quarterly basis using methods found in 40 CFR 98.34(d) (units whose primary fuel is MSW or as the only fuel with a biogenic component) and 40 CFR 98.34(e) (units using other biomass fuels including those that combust tires). The annual biogenic CO_2 mass emissions are calculated by multiplying the total annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from 40 CFR 98.34 (d) or 40 CFR 98.34 (e).

If a facility combusts MSW and/or tires that provide no more than 10 percent of the annual heat input, or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW, the following procedure can also be used to estimate the annual CO_2 biogenic emissions. Use Tier 1 Calculation Methodology to determine the total annual CO_2 emissions from combustion of MSW and/or tires in the unit. This result is multiplied by a default factor to determine the annual biogenic CO_2 emissions in metric tons. For MSW the default factor is 0.60 and for tires, the default factor is 0.20. The use of Method 1 Calculation Methodology is forbidden when the annual heat input capacity from tires exceeds 10 percent. If MSW is the primary fuel combusted in a unit or is the only fuel with a biogenic component, refer to 40 CFR 98.34(d) for quantifying the biogenic portion of the CO_2 emissions.

If a facility uses Equation 2-4 to calculate biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel (except MSW), Equation 2-25 can be used to quantify biogenic fuel consumption. Document the use of these calculations in the GHG Monitoring Plan.

If a facility reports CO_2 emissions under 40 CFR 75, biogenic CO_2 emissions from biomass fuels listed in Table 2-5 (except for MSW and tires) may be calculated using the following equation:

$$CO_2 = 1 \times 10^{-3} \times (HI)_A \times EF$$

Equation 2-29

Where:

- **CO_2** = Annual CO_2 mass emissions from the combustion of a particular type of biomass fuel listed in Table 2-5 (metric ton/yr)
- **$(HI)_A$** = Annual heat input from the biomass fuel, obtained, where feasible, from the electronic emissions reports required under 40 CFR 75.64. Where this is not feasible use best available information, as described in 40 CFR 98.33(c)(4)(ii)(C) and (c)(4)(ii)(D) (MMBtu/yr)
- **EF** = CO_2 emission factor for the biomass fuel, from Table 2-5 (kg CO_2/MMBtu)
- **1×10^{-3}** = Conversion factor from kg to metric tons (metric ton/kg)

2.20 Tires

The annual biogenic CO_2 emissions can be estimated if tires provide 10 percent or less of the unit's annual heat input (or if combusted with MSW and the annual heat input for both fuels is less than 10 percent). In this case, it is appropriate to use Tier 1 calculation methodology to quantify the total annual CO_2 emissions and multiply the total annual CO_2 emissions by a default factor to determine the annual biogenic CO_2 emissions. For tires, the default factor is 0.20 and for MSW, the default factor is 0.60. This default factor represents the biogenic fraction of that fuel type of the whole biogenic emissions.

In instances where tire combustion provides more than 10 percent of a unit's annual heat input, the relative proportions of biogenic and non-biogenic CO_2 emissions are determined using procedures outlined in 40 CFR 98.34(d) and 40 CFR 98.34(e). Tires may be reported as part of the mass CO_2 emissions or included in the biogenic report that contains the biogenic CO_2 emissions because tires are partially biogenic. It is imperative that care be taken to avoid double counting tire emissions. If it is elected to report tires separately from mass CO_2 emissions, be sure that those emissions are not included in the mass CO_2 emissions report.

2.21 Monitoring and QA/QC Requirements for Stationary Fuel Combustion Units

Once a facility has determined the appropriate calculation methodology, data must be monitored for quality assurance. Because Tier 1 uses default values in the CO_2 emission calculations, there are no fuel flow calibrations or fuel sampling and analysis requirements for this method. It is very important that all methods/procedures used for the purpose of Monitoring and QA/QC Requirements are documented under the Monitoring Plan.

2.21.1 Tier 2 Monitoring and QA/QC Requirements

Tier 2 calculation methodology relies on a calculated HHV to determine CO_2 emissions. There are several requirements that are fuel specific to ensure accurate quantification of CO_2 emissions. Appropriate fuel sampling and analysis methods are listed in 40 CFR 98.34 (a)(6). Note that all fuel samples must be taken at a location in the fuel handling system that provides a true representation of the fuel combusted. Fuel sampling and analysis may be performed more often than is required in order to obtain a more accurate representation of the annual average HHV. In these instances, the results of all valid fuel analyses should be used in the GHG emission calculations. If valid HHV are obtained at less than the minimum frequency, appropriate substitute data shall be used in the emissions calculations. The procedure for handling missing data is discussed in Section 2.26 of this Guide. Note that because Tier 2 calculations depend on fuel flow rates from company records, there are no applicable fuel flow calibration requirements. Document all monitoring methods in the GHG Monitoring Plan.

2.21.2 Natural Gas

The requirements for sampling and analysis for natural gas sources are minimal. Sampling and analysis is required twice in a calendar year with samples taken at least four months apart.

2.21.3 Coal and Fuel Oil (and Other Solid/Liquid Fuel Delivered in Lots)

At least one representative sample is required from each fuel lot. In the case of fuel oil, a sample may be taken when there is an addition of oil to the unit’s storage tank instead of lot sampling. If there are multiple deliveries resulting in multiple additions of fuel oil on a given day, a sample taken after the final delivery will suffice. If multiple deliveries of a particular fuel are received from the same supply source in a calendar month, it is appropriate to consider this as a lot and perform lot sampling. This is conditional upon the owner/operator documenting this procedure in the GHG Monitoring Plan. For coal, the “type” of fuel refers to the rank of the coal and for fuel oil, the “type” of fuel refers to the grade number or classification. Instead of lot sampling, a facility may opt to implement flow proportional sampling, continuous drip sampling, or daily manual oil sampling. If daily manual oil sampling is performed, only sample on the days the fuel is being combusted.

2.21.4 Liquid Fuels other than Fuel Oil

For liquid fuels, excluding fuel oil, sampling and analysis is required at least once per calendar quarter. These samples must be taken at least 30 days apart.

2.21.5 Gaseous Fuels other than Natural Gas

For gaseous fuels, excluding natural gas, sampling and analysis is required at least once per calendar quarter. These samples must be taken at least 30 days apart.

2.21.6 Other Solid Fuels (except MSW)

Weekly sampling is required to obtain composite samples that are analyzed monthly.

2.22 Tier 3 Monitoring and QA/QC Requirements

Tier 3 calculation methodology uses the carbon content of fuel, the molecular weight of a gaseous fuel, and fuel flow meters or tank drop measurements for the determination of mass CO_2 emissions. Therefore, it is important that the quantification of these variables are quality assured. For fuel sampling and analysis, it is required that the method be chosen from those listed in 40 CFR 98.34 (b)(4). Document all monitoring methods in the GHG Monitoring Plan.

2.22.1 Flow Meters

Initial calibration of flow meters is required before any flow measurements may be used to calculate GHG emissions. The procedures for the initial calibration are described in 40 CFR 98.3(i). At some point, flow meters may be required to be recalibrated (flow meters used exclusively for the purpose of unit startup are exempt from recalibration). Examples of approved recalibration methods include using manufacturer's recommended procedures, an appropriate industry consensus standard method, or a method specified in the aforementioned CFR section. Fuel flow meters should be recalibrated at a frequency greater than or equal to that recommended by the manufacturer or by industry standard practice. Document the calibration and/or recalibration method in the Monitoring Plan.

In-situ calibration of the differential pressure, total pressure, and temperature transmitters is sufficient for the initial calibration of an orifice, nozzle, or venturi meter. A Primary Element Inspection (PEI) should be performed at least once every three years. If a mixture of liquid or gaseous fuels is transported by a common pipe, either meter each type of fuel separately or meter the mixed fuel using a calibrated meter.

Fuel billing meters are exempt from initial and on-going calibration requirements and from the Monitoring Plan and other recordkeeping requirements as long as the owners/operators of the facility share no common ownership with the suppliers of the fuel. Meters used exclusively to measure the flow rates of fuels that are used only for unit startup are also exempt from initial and ongoing calibrations.

2.22.2 Tank Measurement

If used to quantify the volume of liquid fuel use, oil tank drop measurements must be performed according to any appropriate method published by a consensus-based standards organization, such as the American Petroleum Institute (API).

2.22.3 Carbon Content and Molecular Weight Determination

Tier 3 calculation methodology utilizes the carbon content and/or molecular weight from the fuel to determine mass CO_2 emissions. Therefore, it is imperative that these numbers are quality assured. It is important that all fuel samples are an accurate representation of the fuel combusted and analysis may be performed by either the owner/operator or supplier. When sampling frequency is based on a specific time period, fuel sampling and analysis is required only for those time periods in which the fuel is combusted. If sampling and analysis is performed on a greater frequency than the minimum requirement, the results of all valid fuel analyses should be used in the GHG emission calculations. If sampling and analysis is performed at a frequency that is less than that which is required, use appropriate substitute data in the emissions calculations. The procedures for substituting missing data is provided in Section 2.26 of this document.

2.22.4 Natural Gas

Sampling and analysis is required twice a year for natural gas with samples taken at least four months apart.

2.22.5 Coal and Fuel Oil (and Other Solid/Liquid Fuel Delivered in Lots)

At least one representative sample is required from each fuel lot. In the case of fuel oil, a sample may be taken when there is an addition of oil to the unit's storage tank instead of lot sampling. If there are multiple deliveries resulting in multiple additions of fuel oil on a given day, a sample taken after the final delivery will suffice. If multiple deliveries of a particular fuel are received from the same supply source in a calendar month, it is appropriate to consider this as a lot and perform lot sampling. For lot sampling, coal "type" refers to the rank of the coal and for fuel oil, the "type" refers to the grade number or classification. Document lot sampling in the GHG Monitoring Plan. Instead of lot sampling, a facility may opt to implement flow proportional sampling, continuous drip sampling, or daily manual oil sampling. If daily manual oil sampling is performed, only sample on the days the fuel is being combusted.

2.22.6 Liquid Fuels other than Fuel Oil and for Biogas

Sampling and analysis is required at least once per calendar quarter with samples taken at least 30 days apart.

2.22.7 Gaseous Fuels other than Natural Gas and Biogas

Daily sampling and analysis to determine the carbon content and molecular weight of a gaseous fuel is required if continuous, on-line equipment (such as a gas chromatograph) is in place to take these measurements. Otherwise, weekly sampling and analysis must be performed.

2.22.8 Other Solid Fuels (except MSW)

Weekly sampling is required to obtain composite samples that are analyzed monthly. This differs from the solid fuels mentioned above as those fuels are delivered in lots.

2.22.9 Fuel Blends

For solid fuel blends, weekly sampling is required to obtain a composite sample that is analyzed monthly. Liquid fuel blends or gas mixtures composed of only natural gas and biogas, requires sampling and analysis at least once per calendar quarter. For gas mixtures that contain gases other than natural gas (including biogas), daily sampling and analysis is required if continuous, on-line equipment is utilized to measure carbon content and molecular weight of the fuel. Otherwise, weekly sampling and analysis shall be performed. If fuel and sampling analysis occurs more often than is prescribed, the results of all valid analyses must be used in the GHG emission calculations. If sampling and analysis occurs less frequently than is prescribed, appropriate substitution values should be used in accordance with missing data procedures.

2.23 Tier 4 Monitoring and QA/QC Requirements

Tier 4 calculation methodology relies on data from installed CEMS on stationary fuel combustion units to calculate annual mass CO_2 emissions. It is therefore important that the equipment is properly calibrated for quality assurance. If, during any operating hour, quality assured data is not obtained with a CO_2 monitor (or a surrogate O_2 monitor), flow rate monitor, or moisture monitor (if applicable), substitute data may be used to replace missing values in accordance with the missing data provisions discussed in Section 2.26 of this document.

2.23.1 Initial Certification for CO_2, Flow Rate, and Moisture Monitors

Prior to the use of data from measurement devices for Tier 4 calculation methodology, it is required that the devices be initially certified for accuracy. This process can be accomplished by following any of the procedures listed here:

- A facility has the option to follow the initial certification and recertification procedures as explained in 40 CFR 75.20(c)(2), (c)(4), and (c)(5) through (c)(7) and the specifications and test procedures as outlined in Appendix A to 40 CFR 75.

- A facility may elect to use the calibration drift test and Relative Accuracy Test Audit (RATA) procedures of Performance Specifications 3 in Appendix B of 40 CFR 60 and Performance Specification 6 in Appendix B of 40 CFR 60.

- A facility may use the provisions of an applicable State continuous monitoring program.

Note: for stack gas volumetric flow rate monitors, RATA required by Appendix B of 40 CFR 75 and the annual RATA of the Continuous Emission Rate Monitoring Systems (CERMS) required by Appendix F of 40 CFR 60, need only be done at the operating level representative of a normal load or process operating conditions.

2.23.2 O_2 Monitors

If an O_2 monitor is used to determine CO_2 concentrations, adhere to the applicable procedures from 40 CFR 75, 40 CFR 60, or applicable state continuous monitoring program for initial and on-going quality assurance. All RATA required of the monitor must be done on a percent CO_2 basis.

2.23.3 On-going Quality Assurance

For on-going quality assurance, a facility may choose to adhere to the procedures outlined in Appendix B of 40 CFR 75, the procedures outlined in Appendix F of 40 CFR 60, or an applicable state continuous monitoring program. If a facility elects to follow the procedure in Appendix F of 40 CFR 60, daily calibration drift assessments for both the CO_2 monitor (or surrogate O_2 monitor) and the flow rate monitor, and conduct cylinder gas audits of the CO_2 concentration monitor in three of four quarters of each year (except for non-operating quarters). This procedure also requires annual RATA of the CO_2 concentration monitor and the CERMS. For stack gas volumetric flow rate monitors, RATA required by Appendix B of 40 CFR 75 and the annual RATA of the CERMS required by Appendix F of 40 CFR 60, need only be done at the operating level representative of a normal load or process operating conditions for on-going quality assurance. Hourly average data from the CEMS must be validated in accordance with 40 CFR 60.13(h)(2)(i) through 40 CFR 60.13 (h)(2)(vi), 40 CFR 75.10 (d)(1), or the hourly data validation requirements of an applicable state CEM regulation.

2.24 Municipal Solid Waste (MSW) and Tires

When MSW is combusted in a unit as either the primary or solitary fuel with a biogenic component, determine the biogenic portion of the CO_2 emissions using methods specified in 40 CFR 98.34(d), except when it is appropriate to use Tier 1 calculation methodology. Follow the same procedure when a unit combusts a combination of biomass and fossil fuels in any proportions. Conduct these methods in every calendar year quarter in which biomass and fossil fuels are co-fired in a unit to determine annual biogenic CO_2 emissions. If the primary fuel for multiple units is either MSW or tires and those units are feed from a common fuel source, testing at only one of the units is sufficient.

2.25 Required Records for QA/QC

An explanation of how the following equation inputs are determined from company records (or best available information when applicable) must accompany any required records:

- Fuel consumption when applied to Tier 1 and Tier 2 calculation methodologies, and in cases where multiple units share a common liquid or gaseous fuel supply, as detailed in 40 CFR 98.36(c)(4).
- Fuel consumption when Tier 3 is used for solid fuel.
- Fossil fuel consumption when the unit uses CEMS and a stack gas flow rate monitor to quantify CO_2 emissions, combusts both fossil and biomass fuel (except MSW or tires), and the emissions consist solely of combustion products.
- Sorbent usage when the sorbent produces CO_2 emissions and 40 CFR 98.33(d) applies.
- Quantity of steam produced by a unit combusting MSW when Tier 2 calculation methodology is appropriate.
- Biogenic fuel consumption and HHV, when Equation 2-25 is used to calculate biogenic emissions.*
- Fuel usage for CH_4 and N_2O emissions calculations if more than one fuel type listed in Table 2-6 is combusted during the reporting year for units that qualify for and elect to use alternative CO_2 mass emission calculation methodologies or use Tier 4 Methodology.
- Mass of biomass combusted for premixed fuels that contain biomass and fossil fuel.

* 40 CFR 98.34(f)(6) states to use sections 98.33(e)(5) and 98.33(e)(6) as procedures to determine and satisfy record keeping requirements for biogenic fuel consumption and HHV from company records/best available information. However, the CFR's do not contain 98.33(e)(6). The December 2010 Federal Register lists changes to 40 CFR 98 and include the deletion of 98.33(e)(4). It is highly suggestive in the latest CFR's that 98.33(e)(5) and 98.33(e)(6) were "moved up" when 98.33(e)(4) was deleted, but the reference to (e)(5) and (e)(6) remained unaltered.

2.26 Procedures for Estimating Missing Data for Stationary Combustion Units

There may be times when quality assured data are unavailable for use in emission calculations and substitute data is needed. For example, equipment may malfunction or a fuel sample may not have been taken for analysis. It is important that all pertinent information is retained and reported as necessary for the GHG report for missing and replacement data values.

For units that use one of the four calculation methodologies and have missing data for the HHV, carbon content, or molecular weight of the fuel, use the arithmetic averages of quality-assured values of that parameter immediately preceding and following the missing data point as a substitute value. In other words, use the two most immediate quality assured values bracketing a missing data point and average those values to obtain an appropriate substitute value for the missing data. If the second bracketing value has not been obtained by the time the GHG report is due, it is appropriate to use the value of the first bracketing value as a substitute for missing data. If there is no quality-assured data available prior to the missing data event, substitute the first quality-assured value obtained after the missing data. If the missing data includes CO_2 concentrations, stack gas flow rate, percent moisture, fuel usage, or sorbent usage, the substitute value used must be based on the best available estimate of the parameter, based on all available process data. Types of process data include electrical load, steam production, or operating hours.

For units that are subject to requirements that are subject to the reporting requirements of 40 CFR 75, missing data substitution procedures of 40 CFR 75 must be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, HHV, and fuel carbon content.

2.27 Data Reporting Requirements for Stationary Fuel Combustion Units

The EPA has developed an annual GHG emissions reporting tool called the Electronic Greenhouse Gas Reporting Tool (e-GGRT). Beginning in 2014 and thereafter, it is required that facilities use this tool for compliance with the MRR.

Once the designated representative has registered the facility in e-GGRT, the software prompts the user through the annual emissions report process. The user is prompted to select a source category and configuration (single unit, aggregation of unit, common pipe, common stack, or Alternative Part 75 reporters). Once the appropriate selection has been made, the user inputs unit level specific information. This information fulfills the data reporting requirements of 40 CFR 98.36.

Air Force bases that own/operate Stationary Combustion units that are subject to the MRR have two options for entering data into e-GGRT. One option is to directly enter into e-GGRT inputs to equations. This option does not keep inputs to equations data entered into e-GGRT confidential. The other option is to use the Inputs Verifier Tool (IVT), which does keep inputs to equations confidential. Use the IVT when reporting and keep all documents/records/summaries for at least five years.

IVT is embedded in e-GGRT software and automatically conducts electronic verification checks on the equation inputs. If a data element entered into the software produces a warning message for the data value, you may provide an explanation in the verification software of why the data value is not being revised. A verification summary is generated for the EPA for verification results. Keep this verification summary as it satisfies the recordkeeping requirement of 40 CFR 98.37 (b)(1) through 40 CFR 98.37 (b)(26). Note that IVT will not retain any inputs to the equations; therefore, maintain the file listing of the inputs used in the equations entered into IVT as a record for five years. Also note that IVT will time out after 25 minutes of non-use and all information will be lost; therefore, the file should be saved locally if the user wants to upload the file and continue working on the data later. Facilities access the IVT module from the Fuel-specific Emissions page.

2.28 Mandatory Greenhouse Gas Reporting Rule Exit Strategy

NOTE: If the facility intends to discontinue reporting under 40 CFR Part 98 after the current reporting year for the reasons of "cessation of operations" or "exiting the program", the facility is required to notify EPA by March 31 that they will not be reporting for the **next** reporting year. This notification does not impact the facility's reporting obligations for the current reporting year.

For most rules promulgated by the EPA, if an entity becomes subject to that rule, that entity will be subject to that rule indefinitely ("once in, always in"). However, that is not the case with MRR. The provisions of 40 CFR 98.2(i) allow facilities that are subject to the rule to cease reporting, including facilities that accidentally/voluntarily report their emissions; however, there are specific criteria for discontinuing reporting. Figure 2-3, *USAF MRR Exit Strategy*, depicts the pathway out of the MRR reporting requirements.

Keep all associated documents used to demonstrate that the facility is no longer (or never was) required to report for at least five years from the date the record was created. The corresponding records required under 40 CFR 98.3(g) must be maintained for each of the five consecutive years prior to notification of discontinuation of reporting and those records must be retained for three years following the year that reporting was discontinued [40 CFR 98.2(i)(1)]. These records include, but are not limited to, list of affected units, calculations, annual GHG emission reports, and monitoring plans. Also, if the facility uses verification software specified by the Administrator, then all records required for the facility must be retained for at least 5 years from the date of submission of the annual GHG report for the reporting year in which the record was generated, starting with records for reporting year 2010

2.28.1 Exit Strategy for Facilities Subject to MRR

To ensure data consistency, once a facility is subject to the MRR, reporting must continue for each year thereafter even if the facility does not meet the applicability requirements in a future year. Nevertheless, the facility may exit the emissions reporting program when the facility no longer emits GHGs or no longer meets the applicability requirements for a specified number of consecutive years. For example, a facility lowers their GHG emissions through change of operations or facility partitioning. However, the facility must resume reporting if annual emissions in any future calendar year causes the facility to emit 25,000 metric tons of CO_2e per year or more.

In any case, the facility must submit a notification to the EPA Administrator that announces the termination of reporting. The facility can select the appropriate reason for discontinuing reporting for the next reporting year in e-GGRT. The following reporting year, the facility will be identified in the Data Reporting tab under the "Facilities Not Expected to Report" section. If the facility is erroneously identified as "Expected to Report" the EPA Administrator needs to be notified that the facility or supplier will not be submitting a report for that reporting year (this can be done in e-GGRT).

- **Cessation of Operations:** To discontinue reporting under “Cessation of Operations”, all applicable GHG-emitting processes and operations must have ceased to operate in the current reporting year. All applicable processes and operations must be certified as closed. Seasonal or temporary cessation of operations do not qualify [40 CFR 98.2(i)(3)]. Base closure is an example of cessation of operations.

- **Alteration of Operations:** To discontinue reporting for this reason, all applicable operations and processes changed such that the entire facility (all subparts) no longer meets the definition(s) of source category(s) as specified in the applicable subpart(s). The change(s) must persist for an entire reporting year. [40 CFR 98.2(i)(5)].

- **Exiting the Program Because of Decreased GHG Emissions:** To discontinue reporting for this reason, the facility must have reported emissions in consecutive previous years that qualify for exiting the program. Records must be maintained for each year in question and for three years following the year that reporting was discontinued. Reporting is no longer required after the facility has reported emissions of either (reporting can be discontinued for the next reporting year immediately after):
  - Five consecutive years of less than 25,000 metric tons CO_2e per year [98.2(i)(1)], or
  - Three consecutive years of less than 15,000 metric tons CO_2e per year [98.2(i)(2)].

2.28.2 Exit Strategy for Facilities Not Subject to MRR (Accidental or Volunteer Reporting)

In general, the GHG MRR will apply only to USAF installations that meet the criteria listed in 40 CFR 98.2(a). If a facility does not meet criteria, the facility is not subject to the requirements of the MRR. The MRR is explicit in 40 CFR §98.2(h): "an owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule…" Once a facility is subject to the requirements of the rule, they must continue to report until they meet the exit requirements. However, it is possible that some facilities mistakenly reported under the MRR when the facility did not meet the threshold requirements. For example, incorrect calculation of emissions or improper aggregation of facilities may have erroneously triggered MRR reporting by overestimating emissions. Retroactively applying facility partitioning may demonstrate that prior reporting was a mistake.

Facilities that accidentally/voluntarily reported should continue to report until they have met the provisions of 40 CFR 98.2(i) to cease reporting. These provisions can be applied **retroactively** to allow facilities that accidentally/voluntarily reported to cease reporting if they can demonstrate that GHG emissions were either:

- Less than 25,000 metric tons of CO_2e per year for the past five years, or
- Less than 15,000 metric tons of CO_2e per year for the past three years.

Corrected GHG emission reports and other corrective measures may be required. If emissions increase to 25,000 metric tons of CO_2e per year or more, the facility must reinitiate annual reporting.

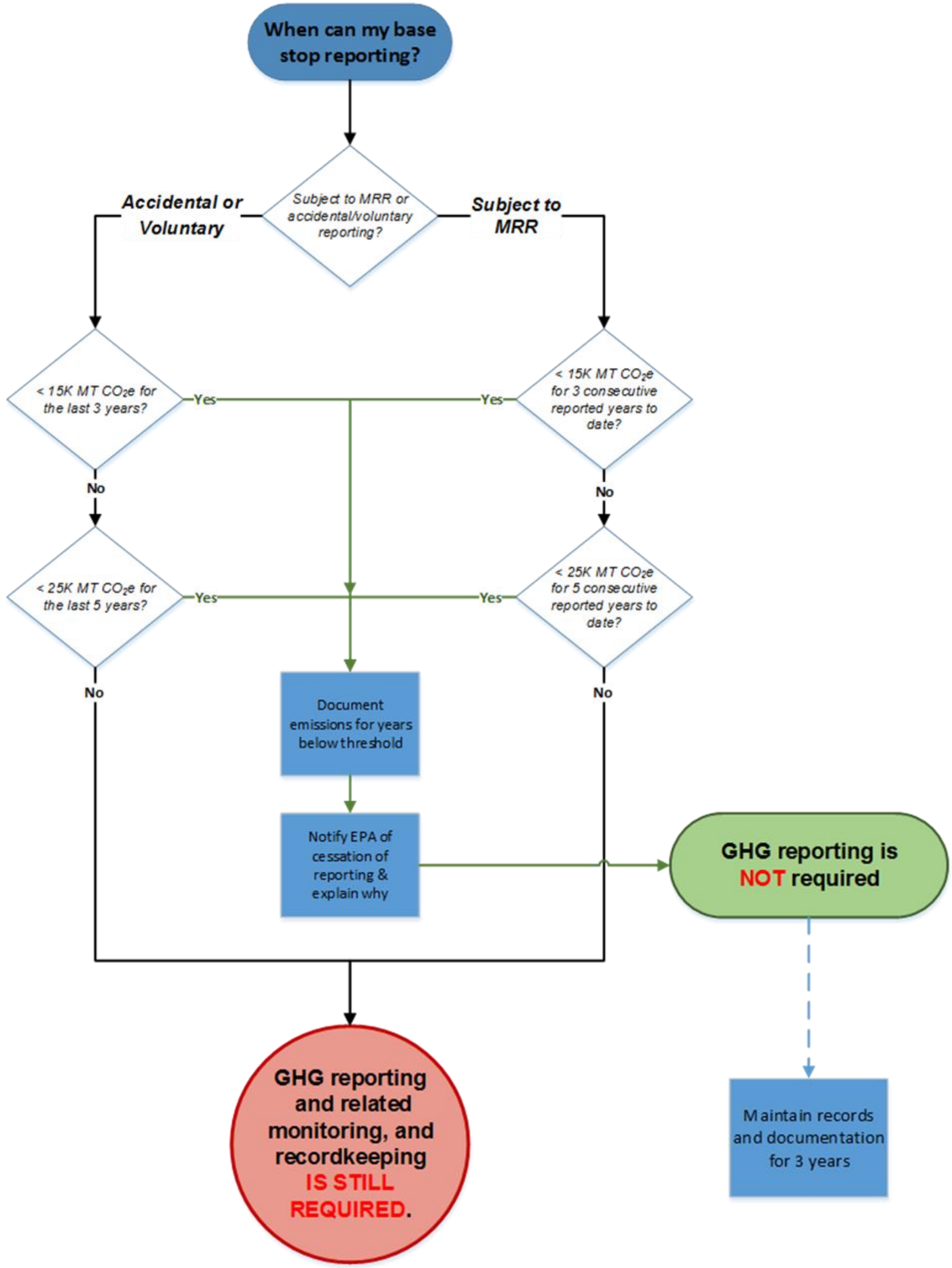

Figure 2-3 USAF MRR Exit Strategy

2.29 Changes for Reporting Year 2017

On 9 December 2016 (81 FR 89188), the EPA finalized several amendments to the MRR, including Subpart A (General Provisions) and Subpart C (General Stationary Fuel Combustion Sources). Although many of the relevant amendments are being discussed in this Guide, the rule should be consulted for a complete review of the changes made by the EPA. The type of amendment dictates how and when it must be addressed. Facilities that undergo changes to monitoring activities will likely need to update their Monitoring Plans.

The following amendments to Subpart C become effective on 1 January 2018 and will be reflected in the Reporting Year 2017 Annual Report:

- The revisions to Table A-5 to Subpart A [Supplier Category List for §98.2(A)(4)] pertains to Industrial greenhouse gas suppliers (subpart OO) and will not impact USAF facilities.

- **Calculating GHG Emissions:** The following Equations will be amended in 40 CFR 98.33 (Calculating GHG Emissions) in paragraph (a)(2)(ii)(A) by revising parameters "$(HHV)_I$," "$(Fuel)_I$," and "n" of Equation C-2b and revising paragraphs (a)(5)(i)(C), (a)(5)(ii)(C), and (a)(5)(iii)(C) to read as follows:

  Paragraph §98.33 (a)(2)(ii)(A) will be amended to:

  $(HHV)_I$ = Measured high heat value of the fuel, for sample period "i" (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per mass or volume).

  $(Fuel)_I$ = Mass or volume of the fuel combusted during the sample period "i," (*e.g.,* monthly, quarterly, semi-annually, or by lot) from company records (express mass in short tons for solid fuel, volume in standard cubic feet (*e.g.,* for gaseous fuel, and volume in gallons for liquid fuel).

  n = Number of sample periods in the year.

  §98.33 (a)(5)(i)(C): Divide the cumulative annual CO_2 mass emissions value by 1.1023 to convert it to metric tons.

  §98.33 (a)(5)(ii)(C): Divide the cumulative annual CO_2 mass emissions value by 1.1023 to convert it to metric tons.

  §98.33 (a)(5)(iii)(C): Divide the cumulative annual CO_2 mass emissions value by 1.1023 to convert it to metric.

- **QA/QC and Monitoring Requirement Change**. Effective 1 January 2018, amend §98.34 (Monitoring and QA/QC) requirements.by revising paragraphs (d) and (e) to read as follows:

  (d) Except as otherwise provided in §98.33(b)(1)(vi) and (vii), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the CO_2 emissions using ASTM D6866-16 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis) and ASTM D7459-08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (both incorporated by reference, see §98.7). Perform the ASTM D7459-08 sampling and the ASTM D6866-16 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8-hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ±5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8-hour and 24-hour test periods. Document the results of the demonstration in the unit's monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (*e.g.,* 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO_2 emissions into the biogenic and non-biogenic fractions using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (*e.g.,* 0.30, if 30 percent of the CO_2 is biogenic). When MSW is the primary fuel for multiple units at the facility, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

  (e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, *e.g.,* tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866-16 and ASTM D7459-08 (both incorporated by reference, see §98.7) may be used to determine the biogenic portion of the CO_2 emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

- **Table C-1 and C-2 of Subpart C Revisions.** As of 1 January 2018, the following tables in Subpart C will be amended as (changed parts are in bold red text; "Tires" were removed from Table C-2 entirely):

TABLE C-1 TO SUBPART C OF PART 98 (PARTIAL TABLE)
DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel Type	Default High Heat Values	Default CO_2 Emission Factor
Petroleum products—solid	**mmBtu/short ton**	**kg CO_2/mmBtu**
Petroleum Coke	**30.00**	**102.41**
Petroleum products—gaseous	**mmBtu/scf**	**kg CO^2/mmBtu**
Petroleum products—liquid	**mmBtu/gallon**	**kg CO_2/mmBtu**
Propane Gas	**2.516 × 10−3**	**61.46**

TABLE C-2 TO SUBPART C OF PART 98
DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel Type	Default CH_4 Emission Factor (kg CH_4/MMBtu)	Default N_2O Emission Factor (kg N_2O/MMBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum Products (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Other Fuels—Solid	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels -Solid (All fuel types listed in Table C-1, except wood and wood residuals)	3.2×10^{-02}	4.2×10^{-03}
Wood and wood residuals	7.2×10^{-03}	3.6×10^{-03}
Biomass Fuels- Gaseous (All fuel types Table C-1)	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels- Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

3 SECTION THREE: GREENHOUSE GAS TAILORING RULE

Note: No sources are subject to any CAA permitting requirements due solely to GHG emissions. The EPA does not treat GHGs as an air pollutant for purposes of determining whether a source is required to obtain a PSD or Title V permit; thus, the Tailoring Rule does not change the fundamental applicability process for those permitting programs. Therefore, this section does not provide details on topics such as permit applicability based on conventional pollutants (non-GHG), definition of a stationary source, routine maintenance, or other similar facets of the PSD or Title V permitting process. Users of this Guide that are affected by or interested in understanding those aspects of the permitting programs should consult with current state, local, and EPA rules, and USAF/DoD guidance for PSD and Title V permitting.

PSD and Title V permits are issued by EPA, state, local, or tribal agencies depending on which agency has delegated permitting authority for the facility's area. States may incorporate by reference PSD and Title V regulations into their regulations or promulgate state regulations that are at least as stringent as the federal regulations. For the purposes of this Guide, only the federal regulations are discussed.

3.1 Prevention of Significant Deterioration and Title V Permits Overview

PSD and Title V permits are part of a dual permitting program that apply to major sources (construction and operating permits). The overall purpose of these permits is to protect public health and the environment during construction, expansion, and operation of sources that have the PTE (or actually emit) significant amounts of air pollutants.

- PSD Permitting (Preconstruction) Program (40 CFR 51.166 and 52.21) - The PSD permitting program is a component of New Source Review (NSR) which authorizes construction and significant modifications of major sources located in areas that are in attainment with the National Ambient Air Quality Standards (NAAQS). There is no NAAQS for GHGs. Major projects are reviewed prior to construction to assure compliance with regulations and to ensure that the air pollution control equipment and procedures determined to be the most effective for the project are included in the permit (BACT). The monitoring, modeling, and BACT requirements vary with the magnitude and type of emissions emitted from the source. If a PSD permit is required based on emissions of non-GHGs, GHGs are addressed in the permit, but only if GHG emissions also exceed their threshold. Since EPA did not establish a threshold for GHG for the other two permitting components of NSR (minor source NSR and major source nonattainment NSR), those segments are not subject to the Tailoring Rule.

- Title V Federal (Operating) Permits (40 CFR Parts 70 and 71) - Major stationary sources and certain other sources are required by the CAA to obtain Title V operating permits. While Title V permits generally do not establish new emissions limits or standards, they are legally-enforceable documents designed to improve regulatory compliance by consolidating and clarifying source-specific applicable and enforceable requirements (federal, state, and local) in a comprehensive document. The permit typically includes emissions limits, monitoring, recordkeeping, and reporting provisions. Frequently, the BACT provisions in the PSD are transferred over to the Title V permit after construction has been completed. Owners of sources with operating permits must report and certify that the source is in compliance each year. The permit needs to be renewed every 5 years.

3.2 Tailoring Rule Purpose

The development and legal background of the Tailoring Rule were previously discussed in the Regulatory Context section in Chapter One of this Guide, so for further information on that topic, please refer to that section. In summary, a major stationary source emits or has the PTE any air pollutant in the amount of at least 100 or 250 tpy, depending on the source category. The EPA recognized that statutory thresholds for PSD permitting are extremely low when applied to GHGs and would result in a flood of new permit applications that regulatory agencies and sources are not prepared to manage. Additionally, the permitting process is typically time consuming and expensive which would cause an undue burden on small to medium sized businesses and hamper economic development. For this reason, the EPA "tailored" the GHG emission thresholds to better fit GHGs.

On 3 October 2016, the EPA published a proposed rule, *Revisions to the PSD and Title V GHG Permitting Regulations and Establishment of a GHG SER*, to fully implement the Supreme Court's decision in the UARG v. EPA case (81 FR 68110). The proposed rule includes:

- Revisions to definitions and other provisions in the PSD and Title V regulations to ensure that the PSD and Title V regulations do not require a source to obtain a permit solely because the source actually emits (or PTE) GHG above the applicable threshold.

- A proposed 75,000 tpy CO_2e SER for GHGs under the PSD program that would establish an appropriate threshold level below which BACT is not required for a source's GHG emissions (the EPA previously refrained from promulgating a de minimis or SER level in the Tailoring Rule).

NOTE: As always, consult the CFR, e-CFR, and the FR for updates to the Tailoring Rule, PSD, Title V, and related regulations. Also, keep in mind that final rules can differ significantly from the proposed rules due to EPA's consideration of comments and other factors.

3.2.1.1 Greenhouse Gas Significant Emission Rate and De Minimis Level

One of the main issues created by the decision in *UARG v. EPA*, was the absence of a threshold of GHG emissions that would trigger BACT requirements for anyway sources. This is a very important concept because the de minimis and Significant Emission Rates (SER) are different from each other:

- De Minimis Emission Rate - emissions below this threshold are considered negligible. The EPA may exempt an "anyway source" from the GHG BACT requirement if the source emits a de minimis (insignificant or trivial) amount of GHGs.

- SER - emissions below this threshold will result in a low concentration/risk. Modifications use lower emissions thresholds to evaluate whether a proposed project at an existing facility is considered a major modification and therefore requires the facility to obtain permits.

In the Tailoring Rule, the EPA specifically refrained from promulgating a de minimis or SER level. To remedy this situation and to comply with the Court's rulings, as part of the 3 October 2016 proposed revisions, the EPA proposed to establish 75,000 tpy CO_2e SER as the de minimis level of GHG emissions.

NOTE: The EPA's interim guidance (discussed in further detail below) is to continue using 75,000 CO_2e tpy of GHG emissions as a "subject to regulation" threshold for determining applicability until either further guidance is issued or a rule establishing a de minimis and/or SER is finalized.

3.2.2 Interim Guidance

Following the *UARG v. EPA* decision, the EPA issued memoranda on 24 July 2014 and 19 December 2014 announcing preliminary views and next steps on the application of PSD to GHGs.

- EPA issued the 24 July 2014 Memorandum, *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*, to assist permitting authorities and sources comply with the regulations in light of the Court's determination. Although outstanding issues remained, EPA provided the following guidance:

  - The EPA will no longer require sources to apply for PSD and Title V permits on the basis of GHG emissions alone ("non-anyway" or "Step 2" sources).

  - EPA confirmed the use of GHG emissions of 75,000 CO_2e tpy as the threshold for triggering BACT requirements for GHG emissions from "anyway" sources.

  - EPA set forth its view that state permitting authorities may continue to require non-anyway sources to obtain PSD and Title V permits if there is independent state authority to do so.

- The 19 December 2014 memorandum, *No Action Assurance Regarding EPA-Issued Step 2 Prevention of Significant Deterioration Permits and Related Title V Requirements Following Utility Air Regulat01y Group v. Environmental Protection Agency*, "anyway" sources that obtained a PSD permit because of non-GHG emissions and have BACT requirements for GHG will need to continue to comply with those requirements.

Additional EPA Guidance on PSD and Title V permitting for GHGs may also be utilized, but guidance issued prior to the 2014 Supreme Court's decision in *UARG v. EPA* must be used cautiously. Although most of the EPA's implementation guidance and tools were developed and issued before *UARG v. EPA*, quite a bit of the guidance, such as for GHG BACT analysis, remains applicable to GHGs and the permitting process.

NOTE: The EPA makes clear that portions of their memorandums and guidance documents are meant to be general guidance, which "does not itself create any rights or impose any new obligations or prohibitions, and is not intended to be a basis for enforcement actions." Additionally, the EPA retains the right to make determinations on a case-by-case basis, if needed.

3.3 Greenhouse Gas Plantwide Applicability Limitations

The permit holder has the option of establishing a Plantwide Applicability Limit (PAL) for facilities at an existing major source. PALs are intended to allow flexibility in the operation of a facility without the need to undergo PSD permitting. A PAL is a pollutant specific annual emission limitation under which the source can make any changes without triggering PSD applicability for that pollutant, as long as the PAL limits are not exceeded:

- PALs are approved for a fixed term (normally ten years).

- Each PAL level is based on a 12-month average, rolled monthly (expressed in tpy).

- Compliance with PALs must be demonstrated monthly during the term of the PAL permit.

- The initial PAL emission rate is calculated through the use of baseline actual emission rates. Each limit is generally established based on the average annual (e.g., baseline) emission rate for a 24-month consecutive period during the prior 10 years of facility operation.

- Step 3 of the Tailoring Rule allows GHG PALs to be established on CO_2e emissions or mass-based emissions, whichever is enforceable as a practical matter for the entire major stationary source.

NOTE: The EPA's October 2016 proposed rule included refining the PSD PAL provisions so that a source that is major for a non-GHG pollutant ("anyway source") could still apply for a GHG PAL to relieve the source from having to address BACT for GHGs.

3.4 Tailoring Rule Applicability

Reminder: GHG means the sum of the following six well-mixed gases: carbon dioxide (CO_2), methane (CH_3), nitrous oxide (NO_x), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perfluorocarbons (PFC). GHGs are primarily emitted by the combustion of fossil fuels; examples of equipment that generate GHG are boilers, hot water heaters, generators, fire pumps, compressors, process heaters and refrigeration equipment. Equipment that is electrically powered does not emit GHGs on site and should not be included in the PTE calculations. For PSD permitting from combustion sources, GHGs are the generally the aggregate of three pollutants: CO_2, CH_4, and NO_x.

3.4.1 Tailoring Rule GHG Calculations

For Tailoring Rule purposes, GHG is calculated in two different ways (i.e., on a mass basis and expressed as CO_2e). These calculations are then compared to a specific threshold to determine applicability:

- GHG on a mass basis is calculated by summing the mass amount of emissions of the six well-mixed gases (mass basis does not incorporate GWP).

- GHG expressed as CO_2e is calculated by summing the resultant values from multiplying the mass amount of each of the six well-mixed gases by each gas's associated GWP. GWP is a measure of how much a given mass of each gas is estimated to contribute to global warming (refer to the GHG MRR section in this Guide for more information on how to make this calculation). GWPs can be found at 40 CFR Part 98, Table A-1 to Subpart A (and in Table A-1 in this Guide's Appendix).

Keep in mind the same PTE rules apply for GHG as with other pollutants, so refer to the USAF PTE Guide for assistance in calculating PTE and to the USAF Stationary Source Guide for Emission Factors. After identifying the equipment that generate GHGs, the calculations involve four basic steps:

1) First, calculate PTE for each GHG emitting unit using this formula:

   GHG PTE = (max design capacity)* x (max operating hrs) x (GHG emission factor)

   *Max design capacity = Maximum rated design capacity of unit. For fuel combustion sources, this information is normally stored on the source's nameplate in Btu/hr, kW, or gal/hr. Values usually need to be converted to MMBtu/hr

2) Second, using the GHG PTE, calculate PTE for each GHG emission unit on a tons/yr mass-basis using this formula (the mass-basis PTE is calculated by summing the PTE of each GHG emitted from the unit):

   GHG Mass Basis = CO_2 + CH_4 + N_2O

3) Third, convert the PTE for each GHG to CO_2e by multiplying the potential GHG emissions by its GWP using this formula (multiply the total annual tons of each GHG pollutant with its respective GWP, and then sum the result):

   GHG CO_2e = (CO_2 x GWP) + (CH_4 x GWP) + (N_2O x GWP)

4) Fourth, compare the CO_2e and mass-basis calculations to the PSD and Title V thresholds (discussed in further detail below).

3.4.2 PSD and Title V Applicability Thresholds

Per the EPA's July 2014 document, *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*, the following "subject to regulation" thresholds will apply until further guidance or a final rule is published with different instructions.

- New "anyway sources": PSD Best Available Control Technology (BACT) will apply for GHGs if the source emits or has the potential to emit 75,000 CO_2e tons per year or more of GHG CO_2e. These requirements will be included in the PSD permit and then incorporated into the Title V permit.

- Existing "anyway sources" must address GHG requirements in their Title V permits when they renew or revise their permits. For a modification, GHG BACT will also apply if both of the following circumstances are present (if the facility makes a significant modification that triggers PSD applicability for GHGs, the requirements of the PSD will need to be incorporated into the Title V permit):

  - The modification is otherwise subject to PSD for a pollutant other than GHG.

- The modification results in a GHG emissions increase and a net GHG emissions increase equal to or greater than 75,000 CO_2e tons per year and greater than zero on a mass basis (this number is zero because at this time there is no SER for GHG).
    - No emissions decreases are considered in these calculations (i.e., if the sum of the change the GHGs on a CO_2e basis and/or mass basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in the calculations to offset increases at other emissions units).

Below are examples of possible scenarios that can occur (remember that these thresholds are subject to change):

Scenario	New or Existing Source	Subject to PSD for Non-GHG?	Source's GHG PTE (CO_2e tpy)	Net GHG Emissions Increase (CO_2e tpy)	Net GHG Emissions Increase (Mass Basis)	Source subject to GHG BACT?
A	New	No	≥ 75,000	N/A	N/A	No
B	New	No	< 75,000	N/A	N/A	No
C	New	Yes	< 75,000	N/A	N/A	No
D	New	Yes	≥ 75,000	N/A	N/A	Yes
E	Existing	No	N/A	≥ 75,000	> 0	No
F	Existing	No	N/A	< 75,000	> 0	No
G	Existing	Yes	N/A	< 75,000	> 0	No
H	Existing	Yes	N/A	≥ 75,000	> 0	Yes

3.5 Tailoring Rule Requirements

Overall, the process for determining PSD and Title V requirements for GHG is not much different than for any other pollutant typically regulated under the PSD permitting program. However, there are some ways GHG is different from the typically regulated pollutant; EPA notes that air quality models, reference data, and other tools are not readily available for the evaluation of GHGs to perform a full GHG BACT review. For example, normally the PSD analysis and review requires air quality modeling to determine if the new emissions will have an impact on the surrounding air quality which could affect compliance with the NAAQS. EPA has not classified GHG as a criteria pollutant and does not intend to set NAAQS for GHG. If a NAAQS is not established for a pollutant, modeling ambient air quality impacts for that respective pollutant is not required as part of the PSD permitting process.

3.5.1 PSD Permit Requirements for Greenhouse Gas

A PSD permit ensures the maintenance of air quality standards through the installation of state of the art control technology when major stationary sources are constructed or significantly modified. The permit addresses the type of construction allowed, the installation of air pollution control devices, emission limits, and subsequent operation of the source. Permitting requirements include:

- A BACT analysis, which is a critical part of the PSD permit application for GHG. BACT is an emissions limitation that is based on the maximum degree of control that can be achieved by the affected source (this may be the only requirement that will apply to sources that emit GHGs and only if the source emits another non-GHG pollutant above the major source emission limits). BACT may be a construction design, equipment requirement, work practice standard, numeric emissions limit, or operational standard.

- An ambient air quality analysis to ensure that the emission increases do not cause or contribute to a violation of any applicable PSD increments or NAAQS (this requirement is not applicable to GHGs because there are no NAAQS or PSD increments for GHGs).

- Class I Area (areas of special national or regional value from a natural, scenic, recreational, or historic perspective) analysis is required to assess the impact of a project if the construction or modification occurs in or near such an area (current climate change modeling is not able to properly quantify the impacts at particular locations attributable to a specific GHG source, so the EPA considers the reduction of GHG emissions to the maximum extent achievable under the BACT requirement to be the best technique to satisfy the Class I area requirements related to GHG).

- An additional impact analysis to determine direct and indirect effects of the proposed source on industrial growth in the area, soil, vegetation and visibility. This involves an evaluation whether there will be an impairment to visibility, soils, and vegetation (but not vegetation with no significant commercial or recreational value) that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification (consistent with the EPA's position on the Class I Area analysis, EPA believes that the focus on reducing GHG emissions to the maximum extent will fulfill this analysis requirement).

3.5.2 Best Available Control Technology Selection

Each new source or modified emission unit subject to PSD is required to undergo a BACT review. The EPA discusses the selection of GHG BACT in the Tailoring Rule and preamble. The EPA does not establish BACT for GHG nor does it offer a new approach for selecting BACT for GHG emissions. A BACT analysis is conducted in a top-down manner, on a case-by-case basis, and considers technical feasibility, cost, and other environmental, and economic impacts. In summary, BACT selection process requires all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. There is currently no technically feasible add-on control technology to reduce GHG emissions, so the EPA's focus has been on energy efficiencies as a BACT for GHG.

The EPA does explain that the traditional BACT analysis, which applies only to the new or modified source (not to the entire facility) should be conducted considering the uniqueness of GHG regulations. EPA's guidance points out that energy efficiency measures can reduce emissions from combustion related pollutants, especially for GHGs.

This Guide does not provide specific BACT for a particular source, since such determinations are made by permitting authorities on a case-by-case basis; however, the process for selecting a BACT is discussed. BACT analysis for GHGs is a simple expansion of the five-step BACT process that has been used for other pollutants. The analysis is designed to identify the best control technology for each specific pollutant, including GHG when applicable. The process begins by reviewing available emission reduction options and narrowing the options by taking into consideration technical feasibility and energy, economic and environmental impacts. GHG BACT should be based on CO_2e, not on individual GHG pollutants. The BACT analysis process requires a substantial amount of documentation and technical evaluation. The five-steps of BACT analysis are:

Step 1: Identify all available control technologies (this usually involves researching control methods used at similar emissions sources) including, but not limited to:

- Processes and designs that lower emissions (not required to include options that "fundamentally redefine the nature of the source").

- GHG BACT should be based on CO_2e, not on individual GHG pollutants.

- Clean fuels unless they redefine the source. EPA noted in the PSD and Title V Permitting Guidance for Greenhouse Gases that certain types of biomass fuel can be considered BACT as determined on a case-by-case basis.

- Innovative control technology; EPA will consider granting waivers if needed [See 40 CFR 52.21(b)(19)].

- Carbon Capture and Storage (CCS), also known as Carbon Sequestration; should be considered for some emitters of GHG, but this option is not likely to be technically or economically feasible.

- GHG MRR requirements are not included in the definition of applicable requirement in 40 CFR 70.2 and 71.2 and should not be included in the Title

V permit. MRR is not regulatory in nature and should not be included in the BACT analysis or in the PSD or Title V permit.

Step 2: Eliminate technically infeasible options (need to show the technology is infeasible based on physical, chemical, or engineering principles). EPA guidance states that lack of vendor guarantees for GHG emissions is not sufficient to eliminate an option.

Step 3: Evaluate and rank remaining control technologies based on environmental effectiveness. For GHGs, EPA guidance suggests using efficiency-based control effectiveness to ensure that the best controls are, in fact, listed first.

Step 4: Evaluate cost effectiveness of controls and energy and other environmental impacts. Historically, economic considerations were the primary focus, but EPA guidance suggests other impacts are more significant for GHG BACT.

- Economics: evaluate direct impacts in dollars per ton of CO_2e emitted.
- Energy: evaluate direct energy consumption.
- Environmental: evaluate indirect or collateral impacts.

Step 5: Select the BACT (select the “top” option unless technical considerations, energy, environmental, or economic impacts justify that option is not “achievable”).

- Work practices are acceptable in lieu of a numerical emission limit if it is technically impractical to establish or ensure compliance with a numerical limit.

3.5.3 Title V Permit Requirements for Greenhouse Gas

The requirement to obtain a Title V Operating Permit will not, by itself, result in the triggering of additional requirements for control of GHG. New Title V Operating Permits will simply incorporate requirements related to GHG emissions (if any) that apply to source. A Title V permit is a legally enforceable document; although it does not impose new requirements for a source (such as air pollution control), it does require that the permit contains emission limitations and other conditions as are necessary to assure compliance with all applicable requirements and includes certain procedural requirements to be followed (such as tracking, reporting, and annually certifying compliance status). The Title V regulations require that Title V permits contain all CAA applicable requirements to which the source is subject, including those for GHGs.

When a source is required to address GHGs in their Title V permit, the permit needs to meet the generally applicable Title V application and permitting requirements for GHGs, such as describing emissions of GHGs and including in the permit any applicable requirements for GHGs established under other CAA programs (e.g., the PSD program). The Title V Permit will need include, if applicable to the source:

- Citation and descriptions of any applicable requirements for GHGs (e.g., GHG BACT from the PSD analysis).
- Monitoring and testing if any are required for GHGs.
- Compliance certification, testing, monitoring, reporting, and recordkeeping requirements.
- Any other information and requirements for GHGs.

3.5.4 EPA Best Available Control Technology Reference Material

The EPA issued an assortment of guidance and resources to clarify the BACT determination process for GHG emissions:

- EPA published "*PSD and Title V Permitting Guidance for GHGs*" on November 2010 to provide general guidance for the evaluation of GHG BACT.
- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database allows access to GHG control technology determinations issued by air permitting agencies.
- White Papers on GHG Control Measures focuses on sector-specific BACT considerations for industries with high GHG emissions.
- GHG Mitigation Strategies Database includes performance and cost data on current and developing GHG control strategies.
- Technical articles and publications provides insight to evolving GHG related technologies.

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ACRONYMS/ BREVITY CODES

AFB	Air Force Base
APIMS	Air Program Information Management System
BACT	Best Achievable Control Technology
CAA	Clean Air Act
CAA	Clean Air Act
CAAA	Clean Air Act Amendments (of 1990)
CC	Carbon Content
CCS	Carbon Capture and Storage
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CFRM	Continuous Flow Rate Monitor
CONUS	Continental United States
ECOM	External Combustion Engine
EF	Emission Factor
e-GGRT	Electronic Greenhouse Gas Reporting Rule
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
EPAct	Energy Policy Act
FR	Federal Register
FLIGHT	Facility Level Information on Greenhouse Gases Tool
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	High Heat Value
ICOM	Internal Combustion Engine
IPCC	Intergovernmental Panel on Climate Change
IVT	Input Verification Tool
LFG	Landfill Gas
MMBtu	Million British Thermal Units
MRR	Mandatory Reporting Rule
MSW	Municipal Solid Waste
MSWL	Municipal Solid Waste Landfills
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSR	New Source Review
PAL	Plantwide Applicability Limitations
PSD	Prevention of Significant Deterioration
PTE	Potential-to-Emit

QA/QC	Quality Assurance/Quality Control
RATA	Relative Accuracy Test Audits
SER	Significant Emission Rate
SIC	Standard Industrial Classification
USAF	United States Air Force
US	United States
EPA	United States Environmental Protection Agency

ABBREVIATIONS (Shortened form of a word or phrase)

µg	Microgram(s)
µm	Micrometer(s)
A-hr	Ampere-hours
Btu	British Thermal Unit
ºC	Degrees Celsius
C_aCO_3	Calcium Carbonate
CH_4	Methane
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
ºF	Degrees Fahrenheit
gal	Gallon(s)
hp	Horse Power
hr	Hour(s)
kg	Kilogram
kW	Kilowatt(s)
lb	Pound(s)
Mg	Megagram(s) [i.e., metric ton]
mg	Milligram(s)
MMBtu	Million British Thermal Units
N_2O	Nitrous Oxide
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
PFC	Perfluorocarbons
ppm	Parts per Million
scf	Standard Cubic Foot
SF_6	Sulfur Hexafluoride
tpy	Tons per Year
yr	Year(s)

Appendix

APPENDIX A: GREENHOUSE GASES

A.1 Introduction

Greenhouse gases are emitted from man-made and naturally occurring processes and affect the Earth by trapping heat from the sun. In other words, the gases prevent heat from escaping Earth's atmosphere. An abundance of these gases results in an increase of Earth's temperature, which is a driving force of climate change. The primary greenhouse gases released from anthropogenic sources are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and fluorinated gases.

A.2 Global Warming Potential

Greenhouse gases are assigned a Global Warming Potential (GWP). GWP is a measure of how much heat the gas traps in the atmosphere calculated over a specific time interval, typically 100 years. The higher the GWP, the greater the potential for the gas to trap heat, and the more harmful the gas is regarded. CO_2 is used as the baseline gas and assigned a GWP of 1. GWPs of gases commonly used by the AF are in Table A-1. The GWP's are current as of November 2015.

Table A-1. Global Warming Potentials of Greenhouse Gases

Name	Chemical Formula	CAS No.	Global Warming Potential (100 yr.)
Carbon Dioxide	CO_2	124-38-9	1
Methane	CH_4	74-82-8	25(1)
Nitrous Oxide	N_2O	10024-97-2	298(1)
Sulfur hexafluoride	SF_6	2551-62-4	22,800(1)
Trifluoromethyl Sulphur pentafluoride	SF_5CF_3	373-80-8	17,700
PFC-14 (Perfluoromethane)	CF_4	75-73-0	7,390(1)
PFC-116 (Perfluoroethane)	C_2F_6	76-16-4	12,200(1)
PFC-218 (Perfluoropropane)	C_3F_8	76-19-7	8,830(1)
Perfluorocyclopropane	$C\text{-}C_3F_6$	931-9-9	17,340
PFC-3-1-10 (Perfluorobutane)	C_4F_{10}	355-25-9	8,860(1)
PFC-318 (Perfluorocyclobutane)	$C\text{-}C_4F_8$	115-25-3	10,300(1)
PFC-4-1-12 (Perfluoropentane)	C_5F_{12}	678-26-2	9,160(1)
PFC-5-1-14 (Perfluorohexane, FC-72)	C_6F_{14}	355-42-0	9,300(1)
PFC-6-1-12	C_7F_{16}; $CF_3(CF_2)_5CF_3$	335-57-9	7,820(2)

Notes provided at the end of this table.

Table A-1. Global Warming Potentials of Greenhouse Gases (Cont.)

Name	Chemical Formula	CAS No.	Global Warming Potential (100 yr.)
PFC-7-1-18	C_8F_{18}; $CF_3(CF_2)_6CF_3$	307-34-6	7,620(2)
PFC-9-1-18	$C_{10}F_{18}$	306-94-5	7,500
PFPMIE (HT-70)	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	NA	10,300
Perfluorodecalin (cis)	Z-$C_{10}F_{18}$	60433-11-6	7,236(2)
Perfluorodecalin (trans)	E-$C_{10}F_{18}$	60433-12-7	6,288(2)
PFC-1114; TFE	CF_2=CF_2; C_2F_4	116-14-3	0.004(2)
PFC-1216; Dyneon HFP	C_3F_6; CF_3CF=CF_2	116-15-4	0.05(2)
PFC C-1418	C-C_5F_8	559-40-0	1.97(2)
Perfluorobut-2-ene	CF_3CF=$CFCF_3$	360-89-4	1.82(2)
Perfluorobut-1-ene	CF_3CF_2CF=CF_2	357-26-6	0.10(2)
Perfluorobuta-1,3-diene	CF_2=CFCF=CF_2	685-63-2	0.003(2)
HFC-23	CHF_3	75-46-7	14,800 (1)
HFC-32	CH_2F_2	75-10-5	675(1)
HFC-125	C_2HF_5	354-33-6	3,500(1)
HFC-134	$C_2H_2F_4$	359-35-3	1,100(1)
HFC-134a	CH_2FCF_3	811-97-2	1,430(1)
HFC-227ca	$CF_3CF_2CHF_2$	2252-84-8	2,640(2)
HFC-227ea	C_3HF_7	431-89-0	3,220(1)
HFC-236cb	$CH_2FCF_2CF_3$	677-56-5	1,340
HFC-236ea	CHF_2CHFCF_3	431-63-0	1,370
HFC-236fa	$C_3H_2F_6$	690-39-1	9,810(1)
HFC-329p	$CHF_2CF_2CF_2CF_3$	375-17-7	2,360(2)
HFC-43-10mee	$CF_3CFHCFHCF_2CF_3$	138495-42-8	1,640(1)
HFC-41	CH_3F	593-53-3	92(1)
HFC-143	$C_2H_3F_3$	430-66-0	353(1)
HFC-143a	$C_2H_3F_3$	420-46-2	4,470(1)
HFC-152	CH_2FCH_2F	624-72-6	53
HFC-152a	CH_3CHF_2	75-37-6	124(1)

Notes for this table are on the following page.

Table A-1. Global Warming Potentials of Greenhouse Gases (Cont.)

Name	Chemical Formula	CAS No.	Global Warming Potential (100 yr.)
HFC-161	CH_3CH_2F	353-36-6	12
HFC-245ca	$C_3H_3F_5$	679-86-7	693[(1)]
HFC-245cb	$CF_3CF_2CH_3$	1814-88-6	4,620[(2)]
HFC-245ea	$CHF_2CHFCHF_2$	24270-66-4	235[(2)]
HFC-245eb	$CH_2FCHFCF_3$	431-31-2	290[(2)]
HFC-245fa	$CHF_2CH_2CF_3$	460-73-1	1,030
HFC-263fb	$CH_3CH_2CF_3$	421-07-8	76[(2)]
HFC-272ca	$CH_3CF_2CH_3$	420-45-1	144[(2)]
HFC-365mfc	$CH_3CF_2CH_2CF_3$	406-58-6	794
HFC-1132a;VF2	$C_2H_2F_2$, $CF{=}CH_2$	75-38-7	0.04[(2)]
HFC-1141;VF	C_2H_3F, $CH_2{=}CHF$	75-02-5	0.02[(2)]
(E)-HFC-1225ye	$CF_3CF{=}CHF(E)$	10/8/5595	0.06[(2)]
(Z)-HFC-1225ye	$CF_3CF{=}CHF(Z)$	5528-43-8	0.22[(2)]
Solstice 1233zd(E)	$C_3H_2ClF_3$; $CHCl{=}CHCF_3$	102687-65-0	1.34[(2)]
HFC-1234yf; HFO-1234yf	$C_3H_2F_4$; $CF_3CF{=}CH_2$	754-12-1	0.31[(2)]
HFC-1234ze(E)	$C_3H_2F_4$; trans-$CF_3CH{=}CHF$	1645-83-6	0.97[(2)]
HFC-1234ze(Z)	$C_3H_2F_4$; cis-$CF_3CH{=}CHF$; $CF_3CH{=}CHF$	29118-25-0	0.29[(2)]
HFC-1243zf; TFP	$C_3H_3F_3$, $CF_3CH{=}CH_2$	677-21-4	0.12[(2)]
(Z)-HFC-1336	$CF_3CH{=}CHCF_3(Z)$	692-49-9	1.58[(2)]
HFC-1345zfc	$C_2F_5CH{=}CH_2$	374-27-6	0.09[(2)]
Capstone 42-U	$C_6H_3F_9$, $CF_3(CF_2)_3CH{=}CH_2$	19430-93-4	0.16[(2)]
Capstone 62-U	$C_8H_3F_{13}$, $CF_3(CF_2)_5CH{=}CH_2$	25291-17-2	0.11[(2)]
Capstone 82-U	$C_{10}H_3F_{17}$, $CF_3(CF_2)_7CH{=}CH_2$	21652-58-4	0.09[(2)]
Default GWPs for which Chemical-Specific GWPs are NOT listed in Table A-1 40 CFR 98			
Fully fluorinated GHG's			10,000
Saturated HFC's with two or fewer carbon-hydrogen bonds			3,700
Saturdated HFC's with three or more carbon-hydrogen bonds			930
Unsaturated PFCs, HFCs and/or HCFCs			1

SOURCE Table A-1 of "Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency, Subchapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Reporting, Subpart A- General Provision," U.S. Environmental Protection Agency.

[1]The GWP for this compound was updated in the final rule published on November 29, 2013 [78 FR 71904] and effective on January 1, 2014

[2]This compound was added to Table A-1 in the final rule published on December 11, 2014, and effective on January 1, 2015.

A.3 Carbon Dioxide Equivalents for Air Force Installations

It is useful to express emissions of greenhouse gases in terms of carbon dioxide equivalents (CO_2e) for quantitative and comparative purposes. For example, a jet engine may emit more than one greenhouse gas and the amounts of each gas may be different. By converting each gas into carbon dioxide equivalents, it is possible to derive a composite greenhouse gas emissions value that is representative of all types and quantities of GHG's that are emitted from that engine. The following equation is used to sum the emissions from a source and convert them to CO_2e.

$$\mathbf{CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i}$$

Equation A-1

Where,

CO_2e = Carbon dioxide equivalent (lb/MMBtu)
GHG_i = High Heat Value based emission factor of each greenhouse gas (lb/MMBtu)
GWP_i = Global warming potential for each greenhouse gas
n = The number of greenhouse gases emitted

Note that the above equation is used to calculate CO_2e in units of pounds per million British thermal units. Ensure calculations are expressed in the desired units by using appropriate conversion factors. Air Force specific greenhouse gas mass emission data is often poorly quantified. In most cases, it is appropriate to use default emission factors based on the type of fuel combusted. The default values for several fuel types are provided in Table 2-5 and Table 2-6 of this guide.

A.4 Stationary ICOM Example

Assume an Air Force Base has a model year 2005 diesel fired stationary combustion engine that is rated at 800 horsepower with a displacement of 18 L/cylinder. Greenhouse emissions for this engine expressed in **carbon dioxide equivalents** and **in units of lb/MMBtu** are calculated as follows:

Step 1- **Select the appropriate greenhouse gas emission factors (EF_{GHG}) based on high heat values from Table 2-5 and Table 2-6.** The greenhouse gas emission factors for diesel fuel are **73.96 kg CO_2/MMBtu**, **3.0 x 10^{-3} kg CH_4/MMBtu**, and **6.0 x 10^{-4} kg N_2O/MMBtu**. Use GWP values from Table 5.

Step 2- Calculate emissions using Equation 27

$$CO_2e = (EF_{GHG})\times(GWP_{CO_2}) + (EF_{GHG})\times(GWP_{CH_4}) + (EF_{GHG})\times(GWP_{N_2O})$$

$$CO_2e = \left(\frac{73.96\ kg}{MMBtu}\right)\times(1) + \left(\frac{3.0\times10^{-3} kg}{MMBtu}\right)\times(25) + \left(\frac{6.0\times10^{-4} kg}{MMBtu}\right)\times(298)$$

$$CO_2e = \left(\frac{73.96\ kg}{MMBtu}\right) + \left(\frac{0.075\ kg}{MMBtu}\right) + \left(\frac{0.1788\ kg}{MMBtu}\right)$$

$$CO_2e = \frac{74.21\ \cancel{kg}}{MMBtu}\times\left(\frac{2.2046\ lb}{\cancel{kg}}\right)$$

$$\boxed{\boldsymbol{CO_2e = 163.61\,\frac{lb}{MMBtu}}}$$

A.5 Aircraft Engine Cell Testing Example

Assume an Air Force Base must calculate greenhouse gas emissions from jet engine testing performed in a test cell. The engine burns Jet-A fuel (Kerosene-type jet fuel). Greenhouse emissions for this engine expressed in **carbon dioxide equivalents** and **in units of lb/1000 lb** are calculated as follows:

Step 1- **Select the appropriate greenhouse gas emission factors (EF_{GHG}) based on high heat values from Table 2-5 and Table 2-6.** For Kerosene-type jet fuel, the greenhouse gas emission factors are **72.22 kg CO_2/MMBtu**, **3.0 x 10^{-3} kg CH_4/MMBtu**, and **6.0 x 10^{-4} kg N_2O/MMBtu**. Use the GWP values from Table 5.

Step 2- Calculate emissions using Equation 27. For unit conversion, use the high heat value (from Table 2-5) and density for the fuel (0.135MMBtu/gal and 6.67lb/gal respectively).

$$CO_2e = (EF_{GHG})\times(GWP_{CO_2}) + (EF_{GHG})\times(GWP_{CH_4}) + (EF_{GHG})\times(GWP_{N_2O})$$

$$CO_2e = \left(\frac{72.22\ kg}{MMBtu}\right)\times(1) + \left(\frac{3.0\times10^{-3} kg}{MMBtu}\right)\times(25) + \left(\frac{6.0\times10^{-4} kg}{MMBtu}\right)\times(298)$$

$$CO_2e = \left(\frac{72.22\ kg}{MMBtu}\right) + \left(\frac{0.075\ kg}{MMBtu}\right) + \left(\frac{0.1788\ kg}{MMBtu}\right)$$

$$CO_2e = \left(\frac{72.47\ \cancel{kg}}{\cancel{MMBtu}}\right)\times\left(\frac{2.2046\ lb}{\cancel{kg}}\right)\times\left(\frac{0.135\ \cancel{MMBtu}}{\cancel{gal}}\right)\times\left(\frac{\cancel{gal}}{6.67\ lb}\right)\times1000$$

$$\boxed{\boldsymbol{CO_2e = 3,233.67\ \frac{lb}{1000\ lb}}}$$

A.6 Stationary ECOM Example

Assume an Air Force Base has a subbituminous coal-fired ECOM unit. Greenhouse gas emissions from this unit expressed in **carbon dioxide equivalents** and **in units of lb/ton** are calculated as follows:

Step 1- **Select the appropriate greenhouse gas emission factors (EF_{GHG}) based on high heat values from Table 2-5 and Table 2-6.** For subbituminous coal, the greenhouse gas emission factors are **97.17 kg CO_2/MMBtu**, **1.1×10^{-2} kg CH_4/MMBtu**, and **1.6×10^{-3} kg N_2O/MMBtu**. Use the GWP values from Table 5.

Step 2- Calculate emissions using Equation 27. Use the high heat value of subbituminous coal from Table 2-5 for unit conversion.

$$CO_2e = (EF_{GHG})\times\left(GWP_{CO_2}\right) + (EF_{GHG})\times\left(GWP_{CH_4}\right) + (EF_{GHG})\times\left(GWP_{N_2O}\right)$$

$$CO_2e = \left(\frac{97.17kg}{MMBtu}\right)\times(1) + \left(\frac{1.1\times10^{-2}kg}{MMBtu}\right)\times(25) + \left(\frac{1.6\times10^{-3}kg}{MMBtu}\right)\times(298)$$

$$CO_2e = \left(\frac{97.17kg}{MMBtu}\right) + \left(\frac{0.275kg}{MMBtu}\right) + \left(\frac{0.4768kg}{MMBtu}\right)$$

$$CO_2e = \left(\frac{97.92\ \cancel{kg}}{\cancel{MMBtu}}\right)\times\left(\frac{2.2046lb}{\cancel{kg}}\right)\times\left(\frac{17.25\ \cancel{MMBtu}}{ton}\right)$$

$$\boxed{\boldsymbol{CO_2e = 3,723.83\,\frac{lb}{ton}}}$$