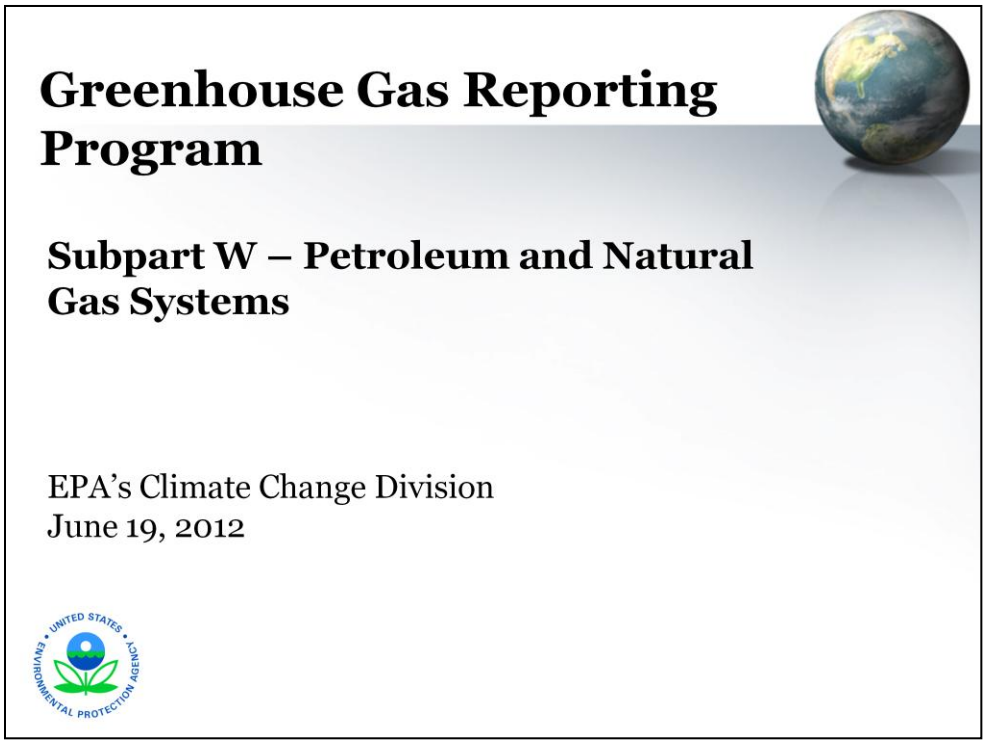
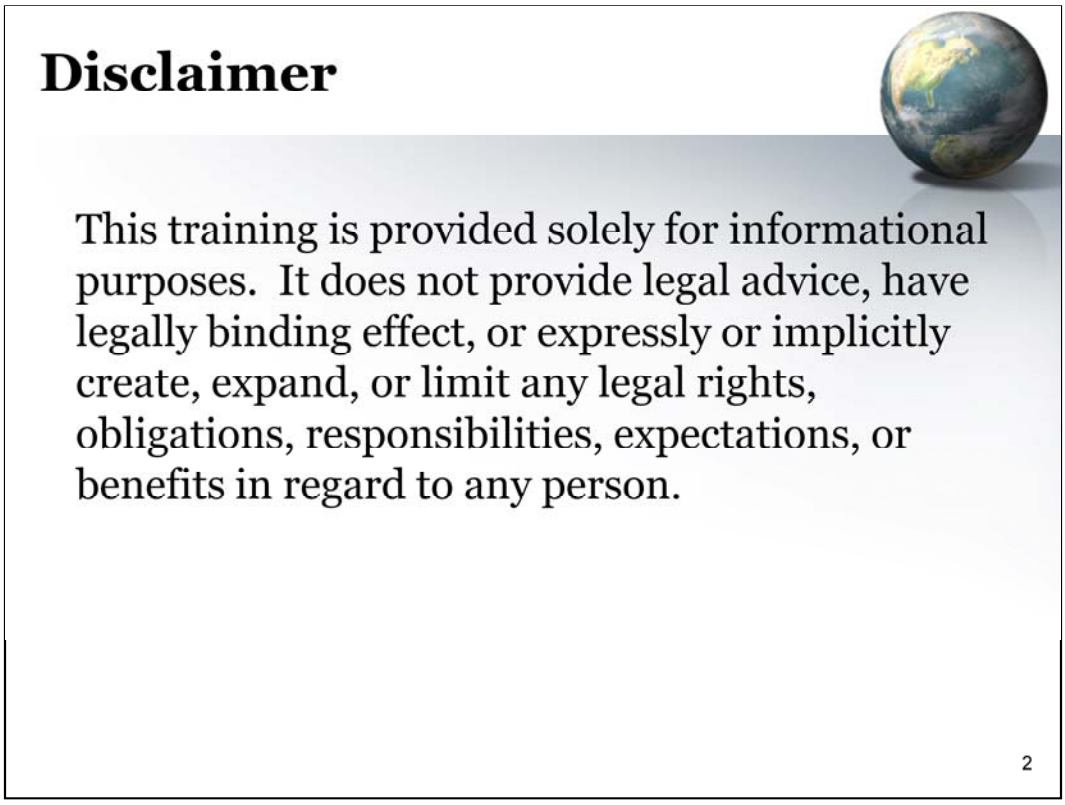


Introduction to Webinar

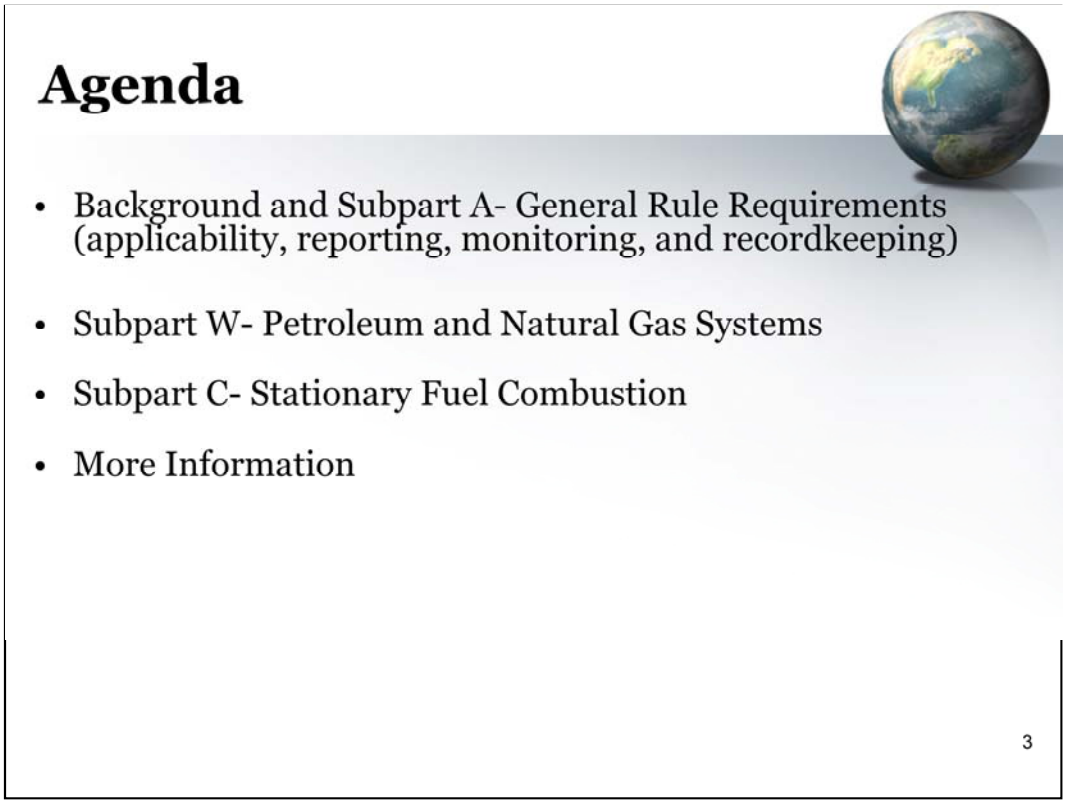
Good afternoon and welcome to EPA's webinar on the GHG Reporting Rule SUBPART W Petroleum and Natural Gas Systems.

I'm with EPA's Climate Change Division which is part of the Office of Air and Radiation in Washington DC. The Climate Change Division is responsible for the development and implementation of the GHG Reporting Program.

Today's webinar will focus on Subpart W – Petroleum and Natural Gas Systems --and will also include a brief introduction to subparts A (General Provisions) and C (Stationary Fuel Combustion).



This training is provided solely for informational purposes. It does not provide legal advice, have legally binding effect, or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits in regard to any person.



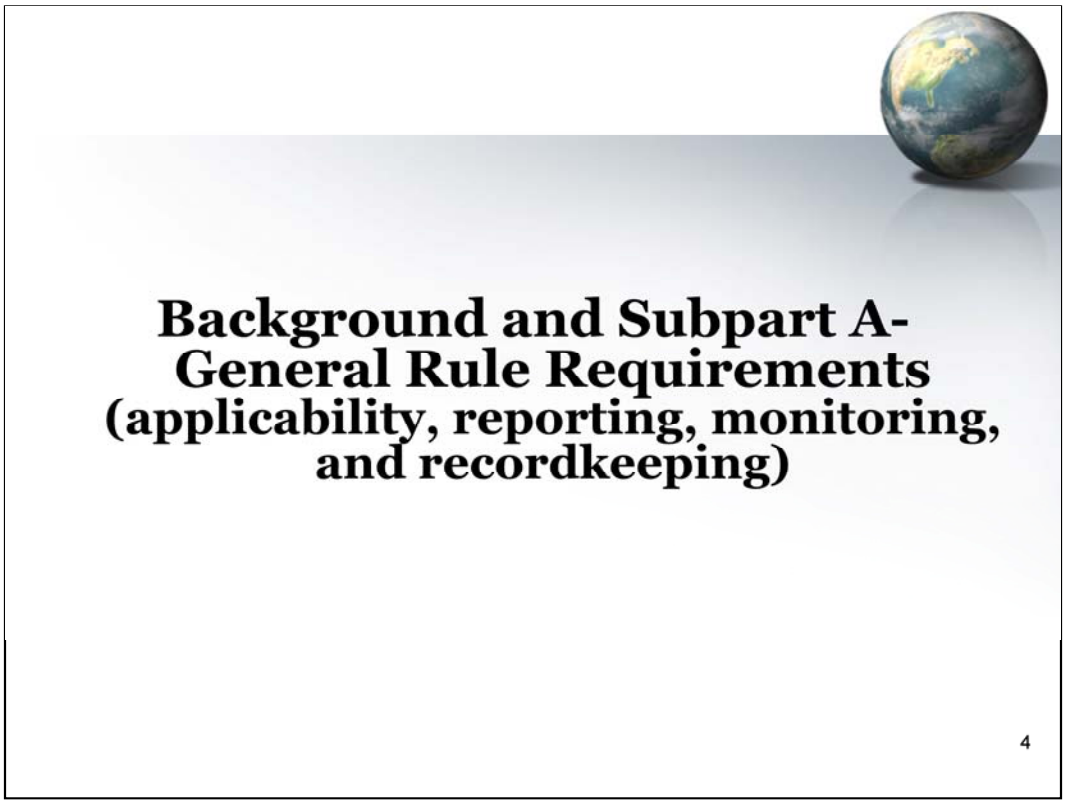
This slide presents an outline of what we are going to present today.

First, we will discuss the Background for the Rule and the General Rule Requirements, including applicability, reporting, monitoring, and recordkeeping requirements

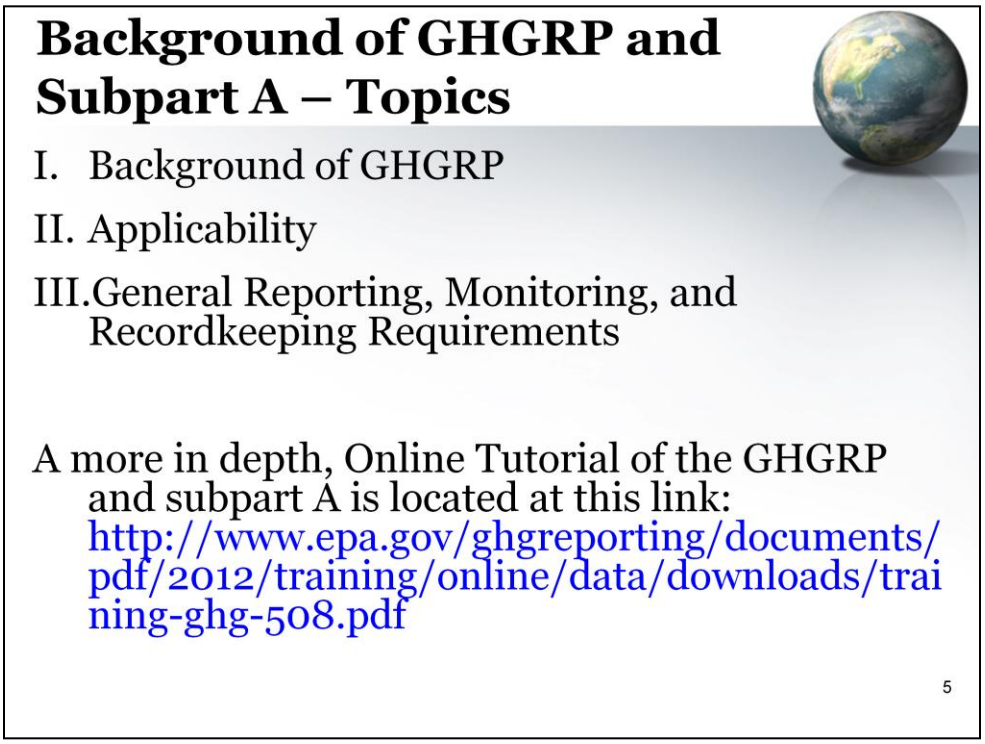
Next, we will talk specifically about Subpart W of the Rule – which specifically addresses Petroleum and Natural Gas Systems.

After that, we will provide a brief overview of Subpart C – which addresses Stationary Fuel Combustion in all industry sectors

Finally, we will provide some sources where you can get More Information on this rule.



Now we will talk about the Background of the GHGRP and Subpart A (the General Provisions).



This slide shows you the topics that we will cover in the subpart A section of this training session.

-First we will go over background information,

-Followed by a review of Applicability

- The general reporting, data monitoring, and recordkeeping requirements,

A great Online Tutorial of the GHGRR and subpart A is located at this link:
http://www.epa.gov/ghgreporting/documents/pdf/2012/training/online/data/downloads/training-ghg-508.pdf

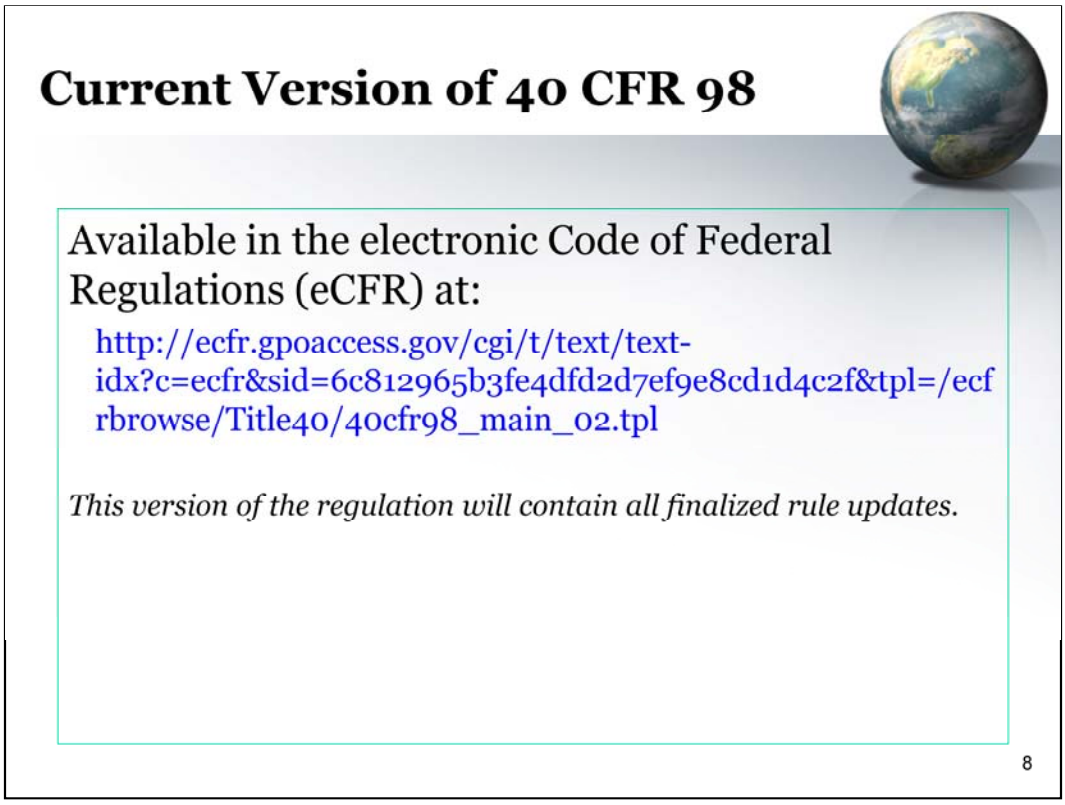
I. Background of Greenhouse Gas Reporting Program

The purpose of the GHGRP is to provide accurate and timely data essential for informing future climate policy decisions. For example, the data will help EPA, states, and the public better understand emissions from specific industries, emissions from individual facilities, factors that influence greenhouse gas emission rates, and actions that facilities could take to reduce emissions.

Data collection began in 2010 for most reporters. In 2011, an additional 12 source categories began collecting data, which will mean that some facilities in 2011 will begin collecting data on additional processes and—in addition—some facilities will begin collecting greenhouse gas data for the first time.

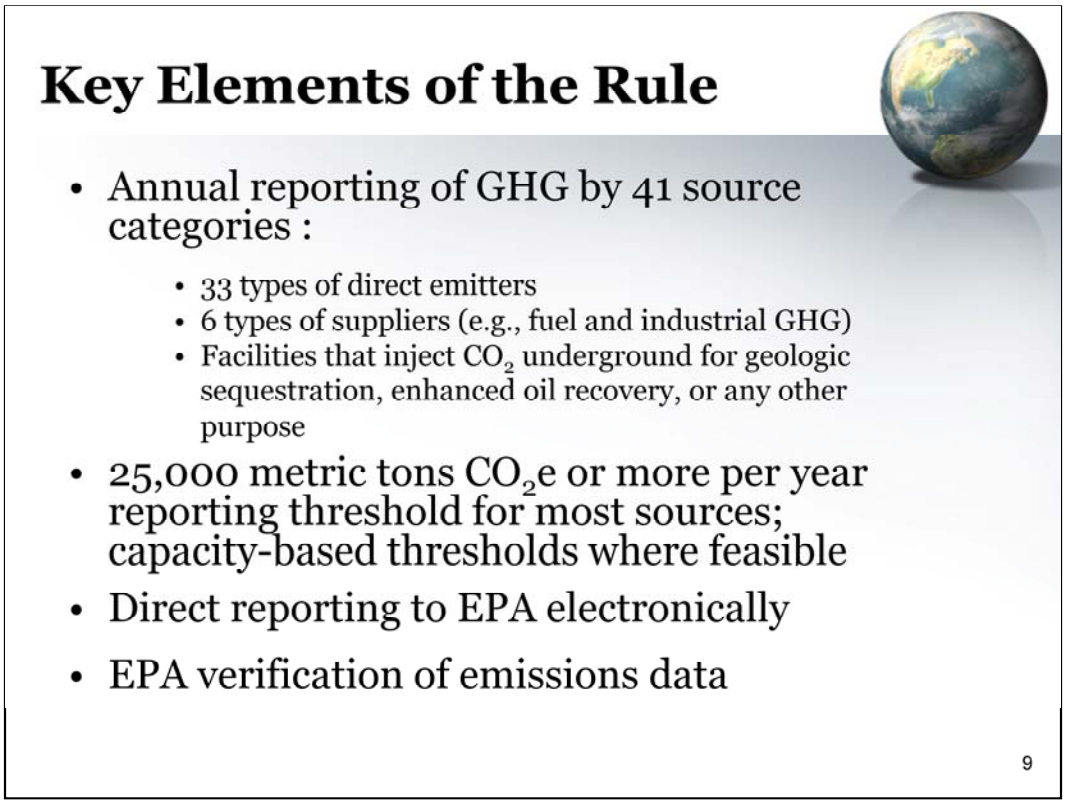
In 2011, about 6,700 facilities reported their calendar year 2010 emissions, and this year, about 10,000 facilities total are expected to report for their 2011 emissions, when the additional industry sectors come under the rule. To be clear, the 10,000 facilities estimate does include overlap with the 6,700 facilities that had already reported their 2010 emissions.

The regulation does not require control of greenhouse gases; it requires only that certain sources monitor and report their GHG information.



40 CFR part 98 has undergone several revisions since initial publication, including changes to subpart W which was promulgated in 2010.

So, you should visit the Code of Federal Regulations website at this address to make sure that you obtain the latest copy of the rule that incorporates all revisions to date for the GHGRR.



The key elements of the rule include the following:

• The rule requires reporting for facilities that directly emit greenhouse gases and for certain suppliers of products.

• *Facilities* must report direct emissions of greenhouse gases from the manufacturing processes and activities used to produce a product and from stationary combustion and miscellaneous use of carbonates.

• *Suppliers* do not report actual emissions from a facility. Suppliers report on the quantity of product placed into the economy and the emissions that would result if the products were completely released, combusted, or oxidized when used by their customers. The rule covers suppliers so that EPA can capture data on greenhouse gases that could be emitted from small facilities and sectors that are not required to report.

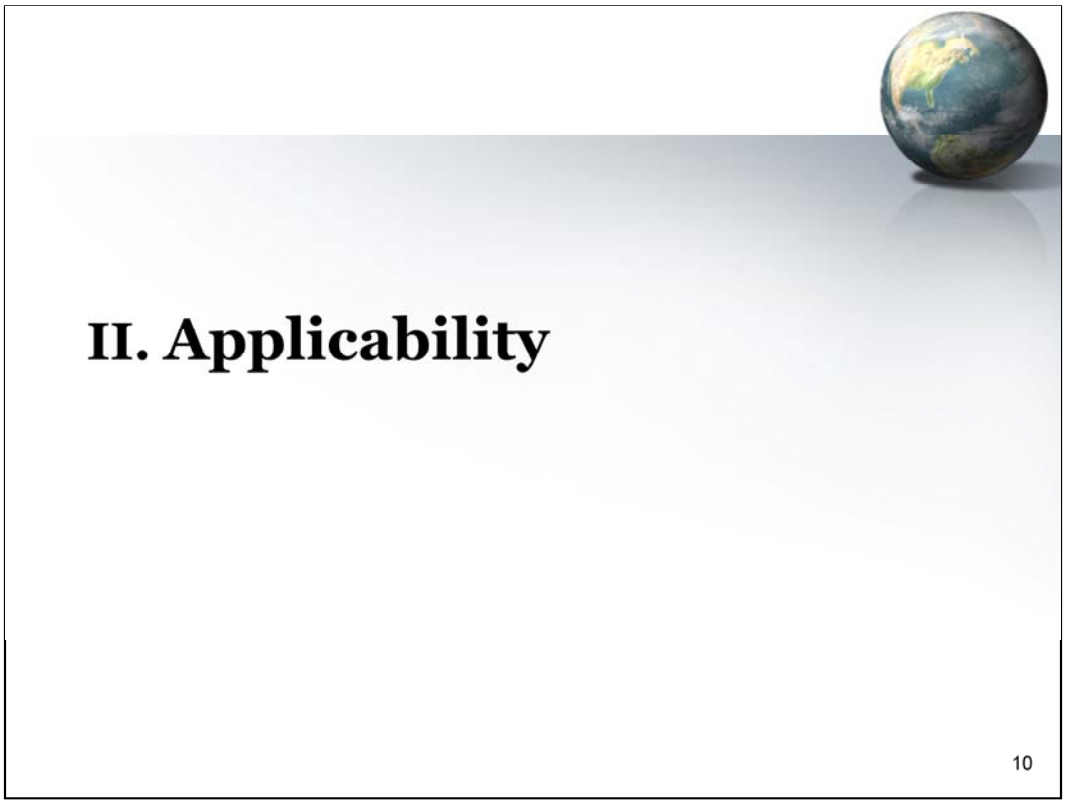
• Facilities that inject CO_2 underground for geologic sequestration, enhanced oil recovery, or any other purpose must also report under the rule.

• The reporting requirements for facilities and suppliers are contained in the regulation, 40 CFR part 98.

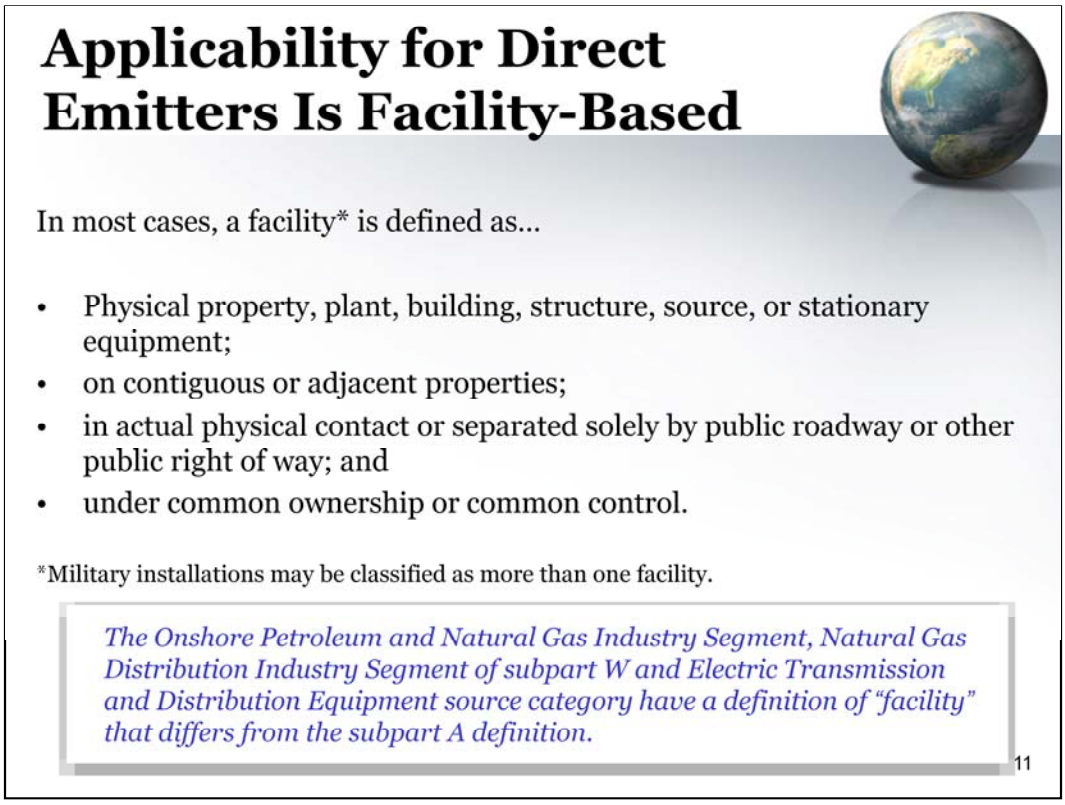
• In general, the GHGRP covers facilities that emit 25,000 metric tons of CO_2 equivalent or more per year. Exceptions to this are discussed in the section of this training on applicability.

• Facilities and suppliers will report directly to EPA.

• EPA will verify all emissions reports. Third-party verification is not required.



This section on applicability will help you determine whether you are required to report under the rule.



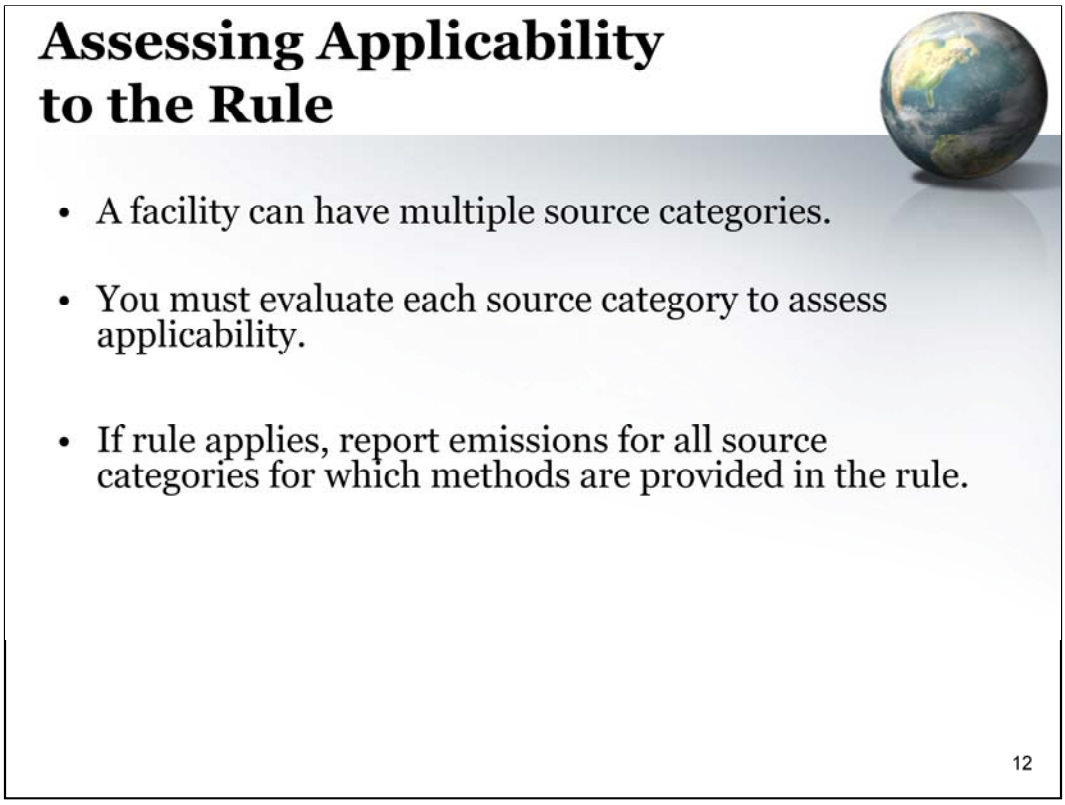
Applicability for direct emitters of greenhouse gases is facility-based NOT at the corporate level. If a corporation owns or operates multiple facilities, you must evaluate *each facility* separately to determine if the rule applies, and report for only those facilities to which the rule applies. Each facility that is subject to the rule must submit its own annual emissions report.

The rule defines a facility as 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, that emits or may emit any greenhouse gas.

Under this definition, a facility cannot be separated into multiple facilities based solely on having different industrial groupings at the site. The facility incorporates *all* equipment on contiguous or adjacent properties that is under common ownership or control. The designation of the facility boundary in your air permit has no bearing on the facility definition for this reporting rule.

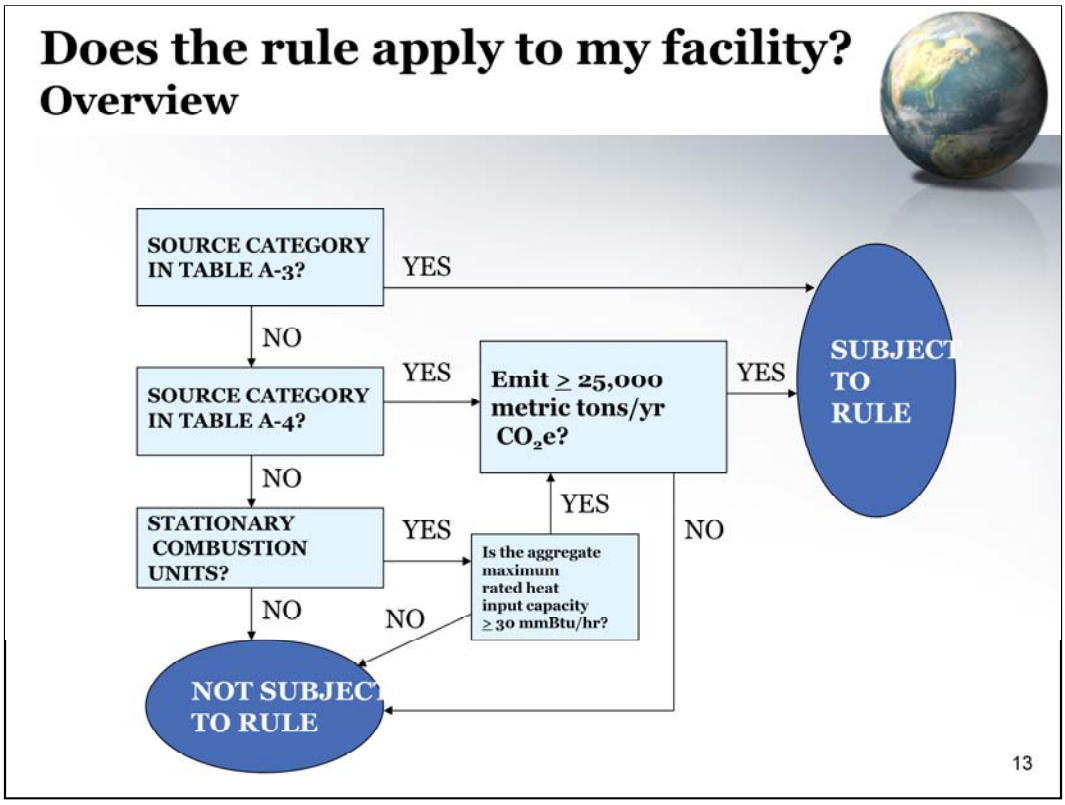
A military installation may be classified as more than one facility for equipment that is owned and operated by separate branches of service.

Also, be aware that a different facility definition applies for onshore petroleum and natural gas production and natural gas distribution in subpart W, and for electrical transmission and distribution equipment use in subpart DD. You should review the definition of facility in these subparts.

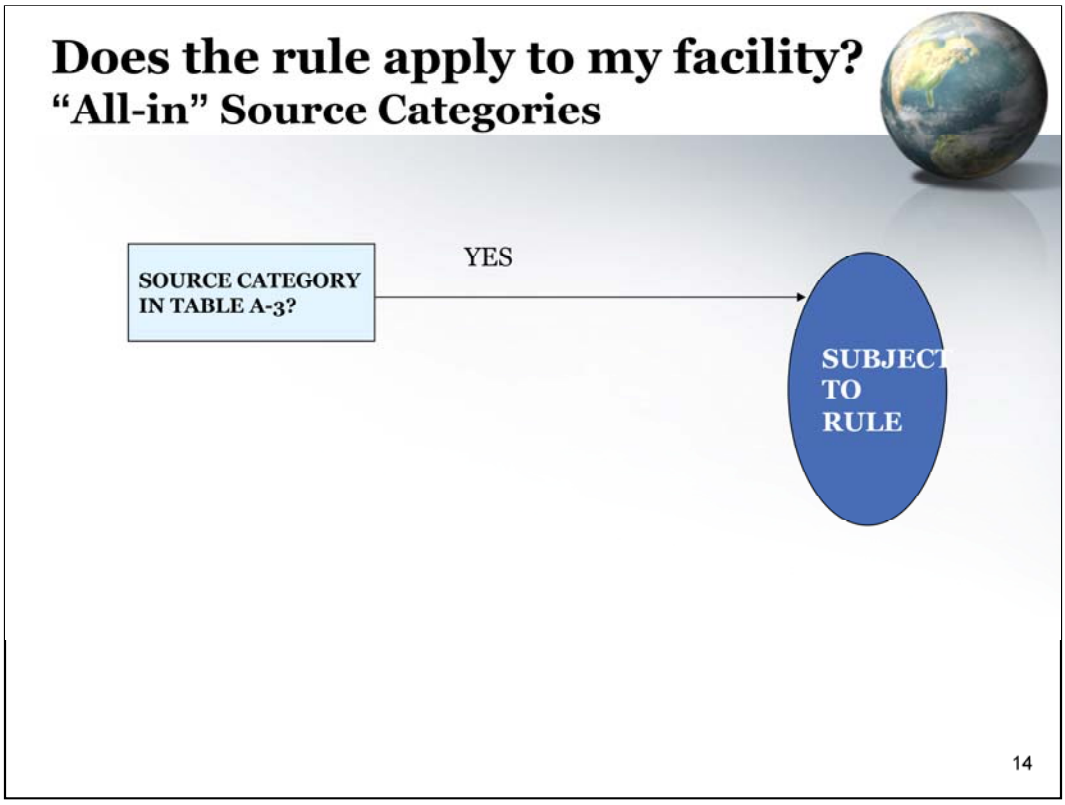


Once you establish the facility boundary, applicability depends on the source categories that are present. The rule defines three types of source categories, which will be discussed in detail in a moment: The so-called “all-in” source categories, the threshold categories, and the stationary fuel combustion sources. If you have multiple source categories on site, you do not designate your facility as being a single source category (for example, based on determining the predominant operation). Rather, you must evaluate each source category to assess applicability.

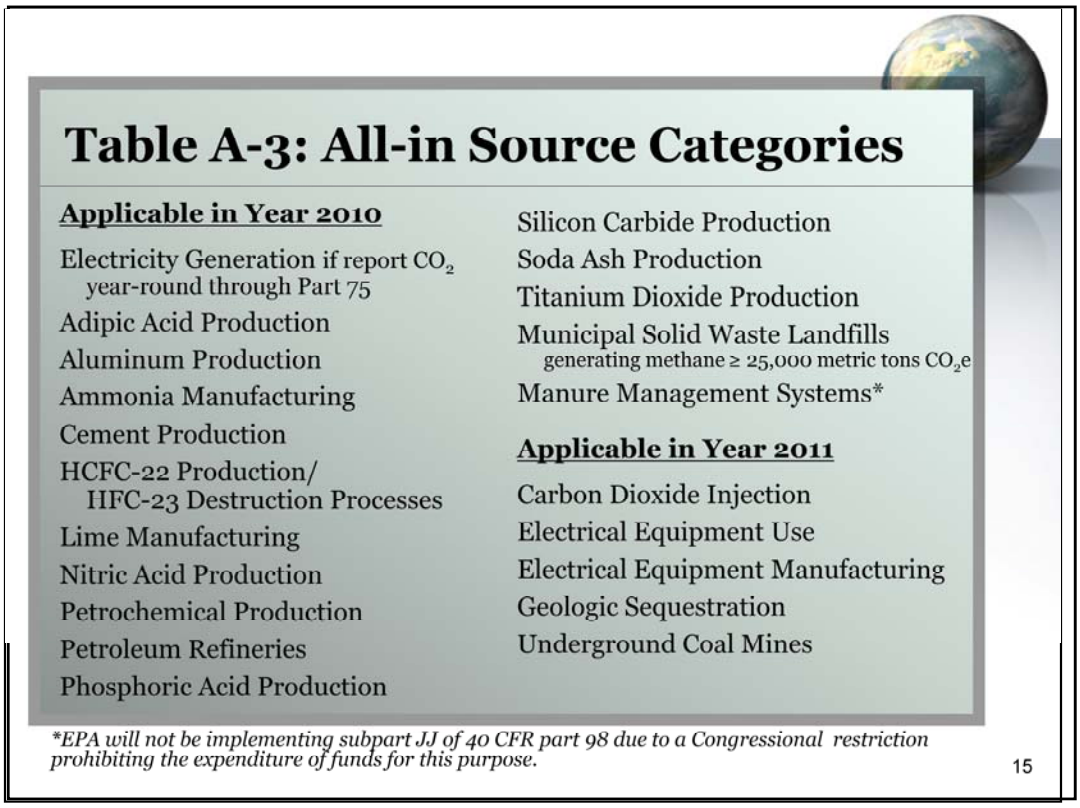
Keep in mind that a facility with multiple source categories can become subject to the rule because of just one category. But if you are subject to the rule, then your greenhouse gas report must cover ALL source categories for which methods are provided in the rule—not just the source category that triggered applicability.



The rule prescribes three criteria for determining whether you must report emissions, shown in the three boxes in the left-hand column of this diagram. You must assess each of these three criteria. If any one applies to the facility, then you must submit an annual greenhouse gas report. We will look at the three criteria one at a time.



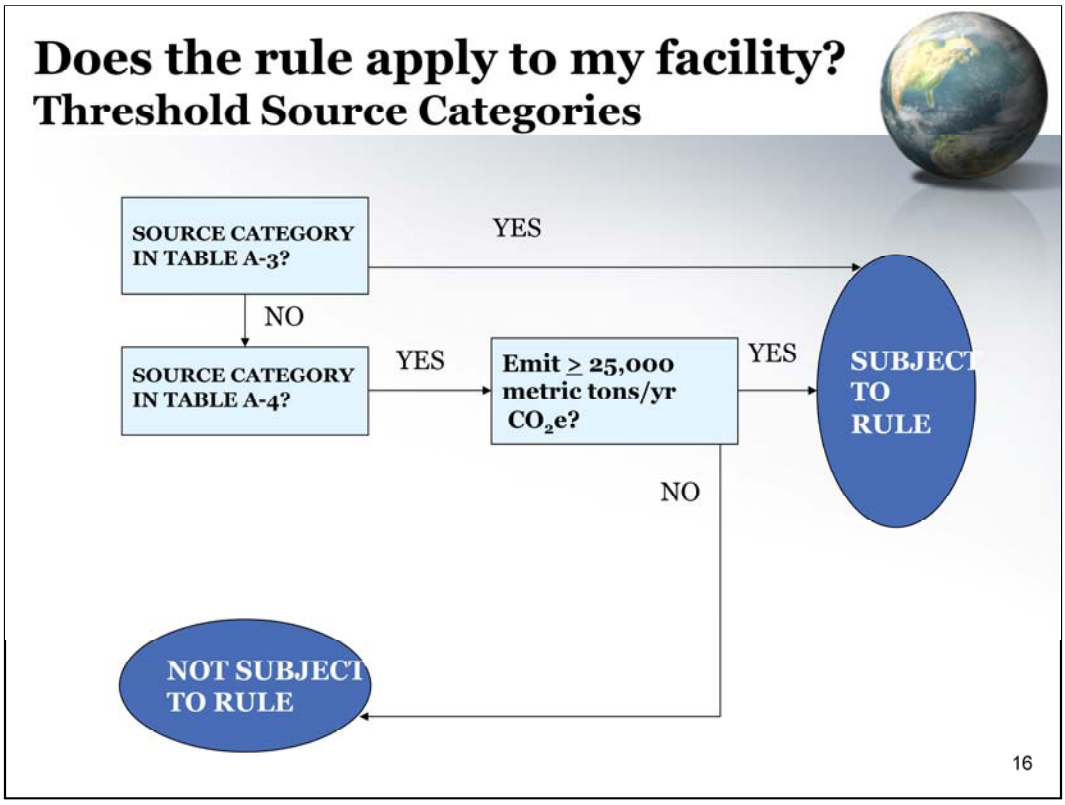
First, Table A-3 in subpart A of the rule has a list of source categories known as "all-in" source categories. If your facility has any of these source categories, then you are automatically subject to the rule, regardless of your emissions level.



Here is the list of the "all-in" source categories, which are defined in each subpart of the rule, as are any exemptions that may apply.

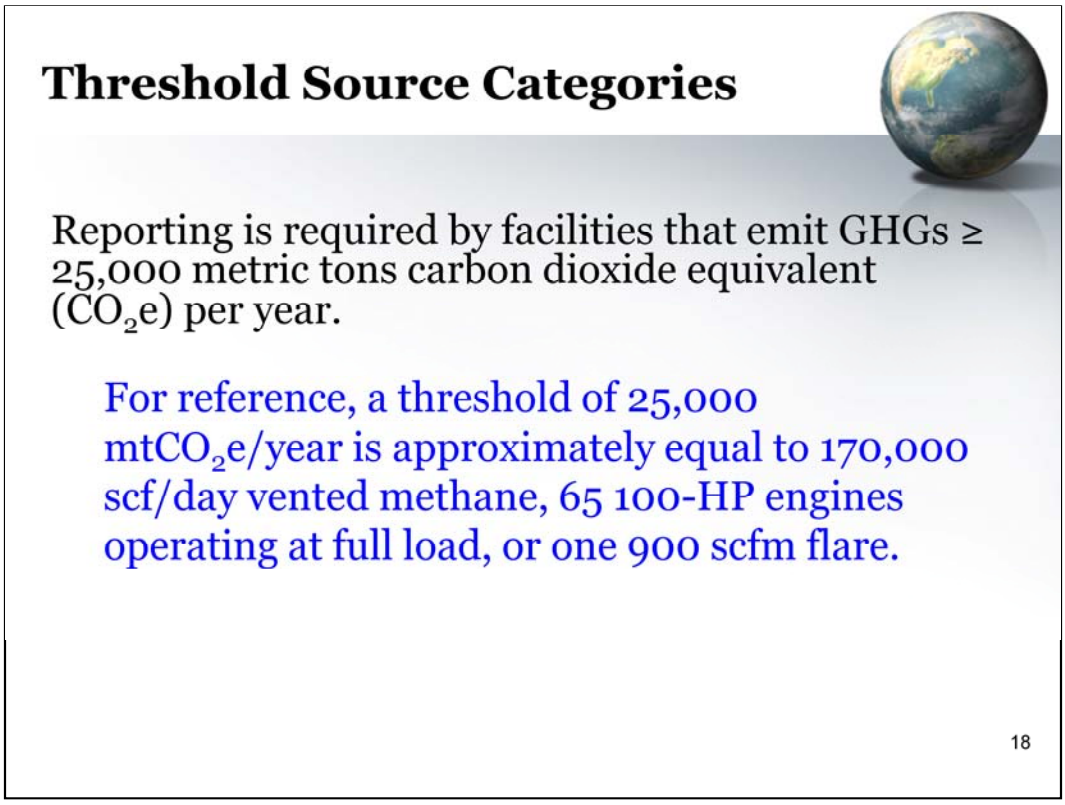
For example, the category of electricity generation includes only facilities with units that report CO_2 mass emissions year-round through part 75, such as units in the Acid Rain Program or the Regional Greenhouse Gas Initiative. On the other hand, if you have a generating unit that supplies power to your facility, or if you sell electricity on grid or to another customer, the unit is not part of this category. Instead, it is treated as a general stationary combustion unit under subpart C, which has different applicability criteria.

So you need to refer to both Table A-3 in subpart A and the definition of the source category in each subpart when assessing applicability. Table A-3 shows the source categories for which annual emissions for calendar year 2010 must be reported, and the additional categories that must be included for calendar year 2011 and beyond.



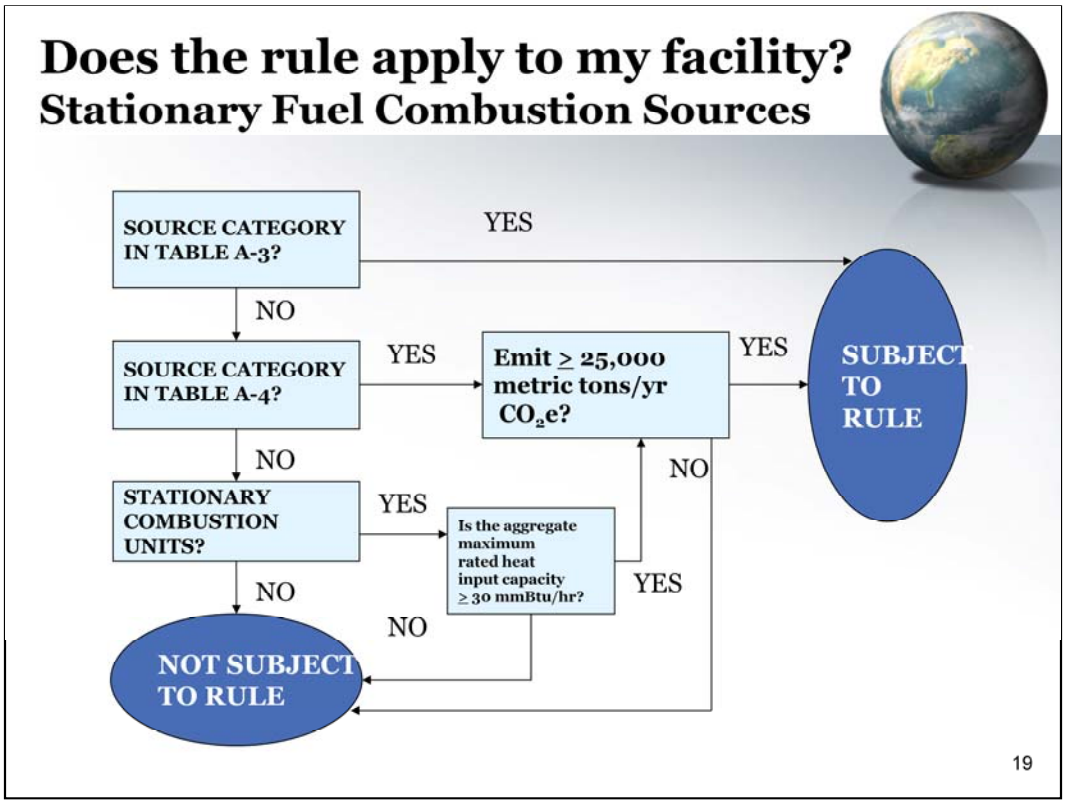
If you do not have a source category in Table A-3, you next look to see if you have a source category in Table A-4, known as a "threshold source category." If you do, you are subject to the rule if your facility emits 25,000 metric tons per year or more of CO_2 equivalent from stationary fuel combustion, miscellaneous carbonate use, and all source categories listed in Table A-4 in subpart A of the rule.

This slide shows the threshold source categories that are applicable starting in reporting year 2010 and the additional categories that apply starting in year 2011. It is important to note that the threshold of 25,000 applies at the facility level, not to each source category. So if a facility contains more than one of these source categories, you include emissions from ALL source categories on site PLUS emissions from all stationary combustion units PLUS emissions from miscellaneous use of carbonates. This total is what you compare to the 25,000 metric tons per year threshold.



Reporting is required by facilities that emit GHGs ≥ 25,000 metric tons carbon dioxide equivalent (CO_2e) per year.

For reference, a threshold of 25,000 $mtCO_2e$ is approximately equal to 170,000 scf/day vented methane, 65 100 HP engines operating at full load, or one 900 scfm flare.



Finally, if you have no source categories in Tables A-3 or A-4, you must consider the third criterion, emissions from stationary fuel combustion sources.

If you emit 25,000 metric tons per year of CO_2e or more from all stationary fuel combustion sources on site, then your facility is subject to the rule. You must include emissions from all stationary combustion units (as defined in the rule) regardless of unit size, such as space heaters, ovens, and water heaters.

EPA wanted to provide a simple way for small facilities to know that they are not subject to the rule. The rule specifies that if the heat input capacity of all units on site is less than 30 million Btus per hour and you have no applicable source categories in Tables A-3 or A-4, the rule does not apply and no emission calculations are needed to determine applicability.

But, if the aggregate maximum heat input capacity of all units on site equals or exceeds 30 million Btus per hour, then you must estimate emissions to see if emissions equal or exceed 25,000 metric tons per year.

What combustion units will emit 25,000 MT CO_2e per year?

Fuel	Design Capacity[1] (mmBtu/hr)	Annual Fuel Use
Coal	30	10,800 tons
Fuel Oil	35	2.3 million gallons
Natural Gas	50	460 million ft^3

[1]Assuming full utilization and 8,760 hours/yr.

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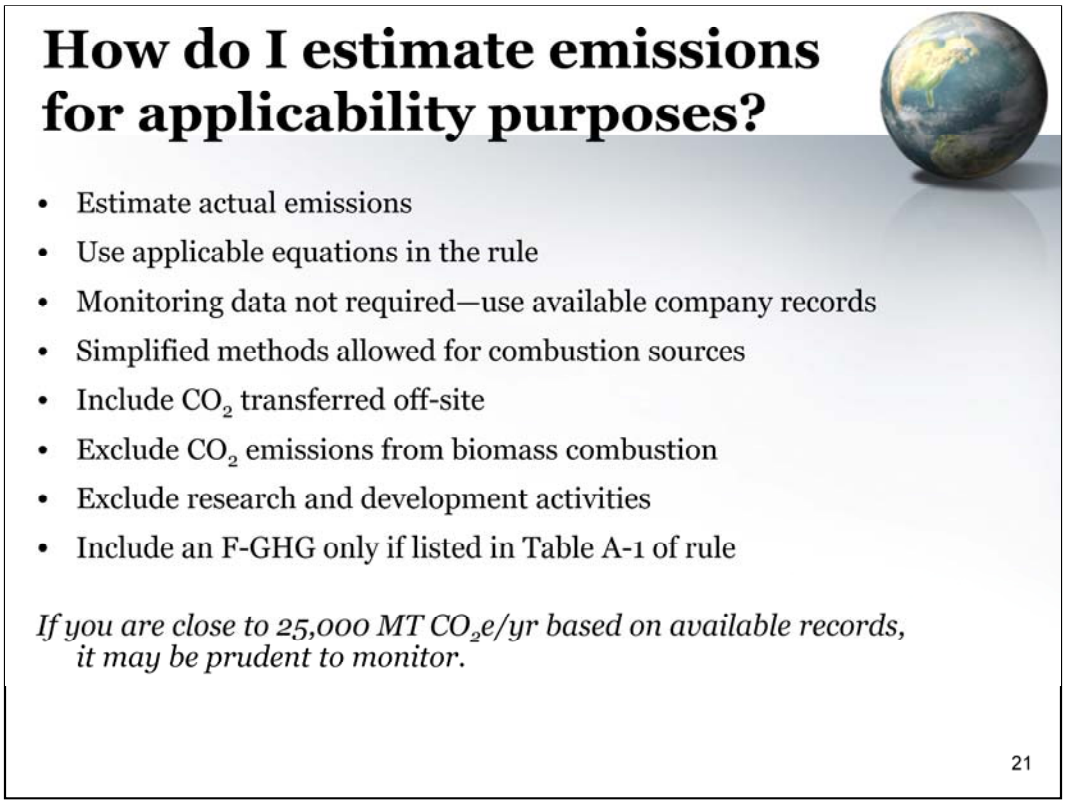
This table gives you an idea of the range of unit sizes that can emit 25,000 metric tons per year of CO_2e.

The design capacity shown in the second column is very conservative, because it assumes full capacity utilization and operation at 8,760 hours per year. So, facilities that contain combustion units that in aggregate are of this capacity or less (and are burning the fuels shown) would not be subject to the rule.

The third column shows annual fuel use, which is probably a better applicability gauge because it shows the actual amount of fuel that would need to be burned to emit 25,000 metric tons per year of CO_2e.



For facilities that are subject to the 25,000 metric tons per year threshold, the rule has specific instructions in subpart A for how to calculate emissions to determine applicability. Keep the following points in mind:

Applicability is based on actual emissions, not potential to emit. Therefore, for processes that are not operated at full capacity, you estimate emissions from the actual operation of the unit during the reporting year.

To estimate emissions for applicability purposes, you must use the emission calculation equations in each applicable subpart. But to provide the emission inputs to the equations, you are not required to monitor—instead, you can use available company records and the likely operating scenario for the reporting year that would lead to the highest greenhouse gas emissions estimate.

Examples of company records include production goals from the company's business plan, process knowledge, engineering estimates, and vendor data.

The rule allows simplified methods of estimating emissions from stationary fuel combustion sources. You can use any of four calculation methodologies specified in subpart C of the rule. The simplest of the four methods, "tier 1," is based on annual fuel use and a default emission factor provided in the rule.

If you capture carbon dioxide for transfer off-site, you must include this CO_2 in your estimate.

You may exclude carbon dioxide from biomass combustion to determine applicability, but you must include emissions of methane and nitrous oxide.

You should refer to the definition of "research and development" in subpart A, to see if any of your equipment qualifies for this exemption. For equipment associated with geologic sequestration of carbon dioxide, additional provisions in subpart RR apply.

For applicability purposes, you need to include only those fluorinated greenhouse gases listed in Table A-1 of the rule.

For most facilities, emissions calculated using available company records are likely to be either significantly above or below the 25,000 metric tons CO_2e per year threshold. However, if you estimate emissions close to the threshold, it would be prudent for you to monitor because, if your actual emissions exceed the threshold during the year, you are legally obligated to submit an annual GHG report.

You do not need to notify EPA if you determine that you are not subject to the rule. In addition, there is no specific recordkeeping requirement for documenting non-applicability, but you might want to keep documentation in case you are audited. Also, remember that if not subject to the rule, you need to reassess applicability every year if there are changes in your processes that increase emissions.

To help you with the applicability determination process, EPA has prepared a web-based applicability tool.

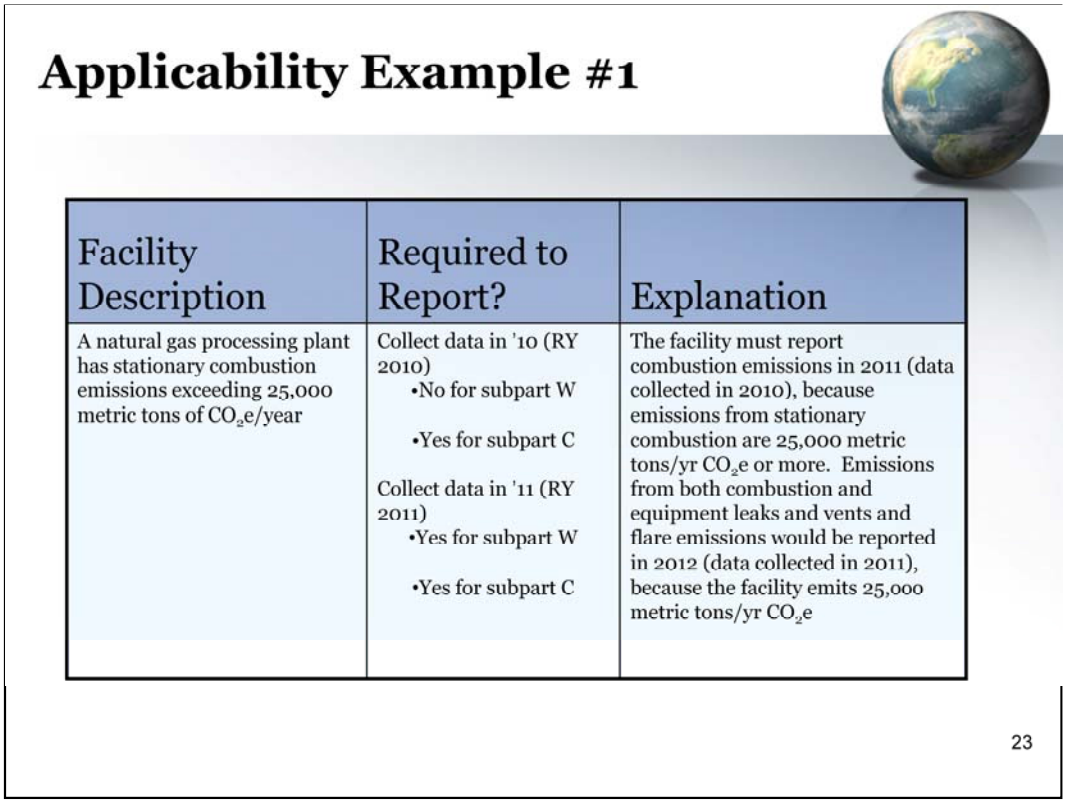
To use this applicability tool, you first select the reporting year and then check-off source categories that are used at the facility. The tool will sort out the all-in versus threshold sources for you, and it has a built-in emission calculator for combustion, a methane generation calculator for municipal landfills, and links to downloadable calculators for some additional source categories (for example, electronics manufacturing, and petroleum and natural gas production).

Based on the information that you provide, the tool will tell you whether your facility is subject to the rule, and if so, which source categories you must report.

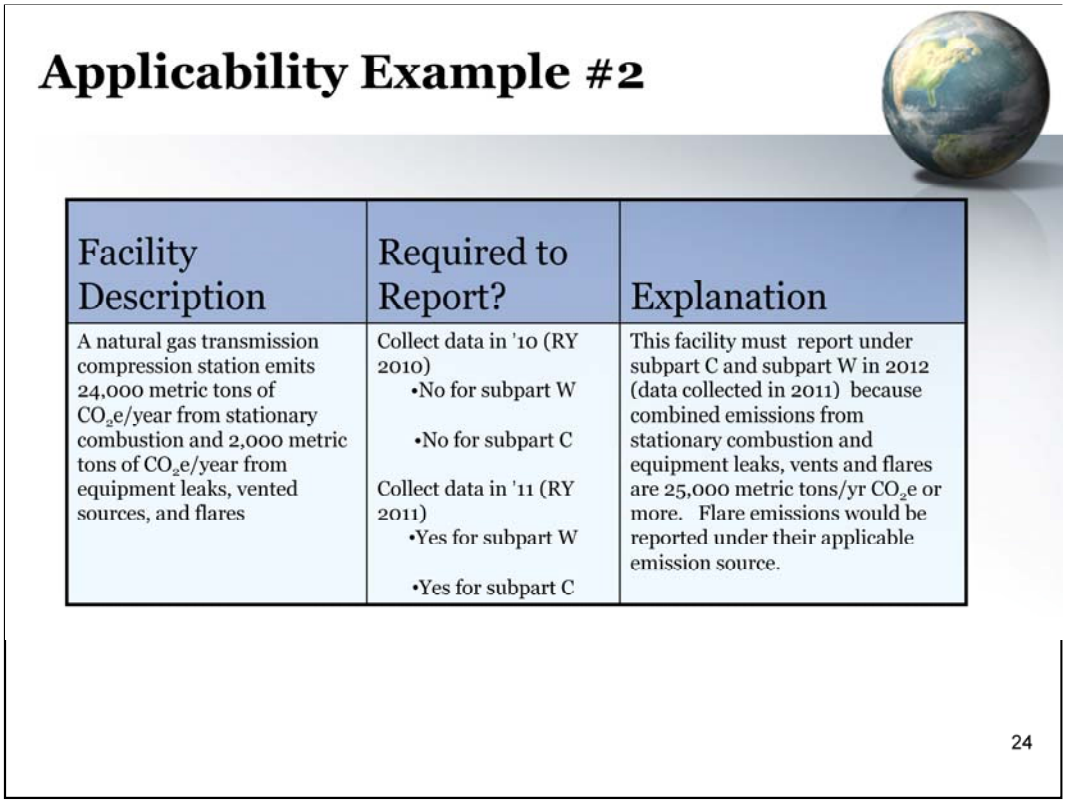
The tool generates a results page that you can retain on file as documentation of your applicability assessment. You can also run the tool to assess how a planned future change to your facility might affect applicability.

In general, the calculators in the tool can provide conservatively high estimates of emissions for some facilities. However, this tool is provided as a guide only, and is not legally binding. It will not provide accurate estimates under all operating conditions. Facilities that are subject to the emissions threshold have the obligation to report if actual emissions are 25,000 metric tons CO_2e or more in any reporting year.

The tool can be found at the web address listed on the slide.

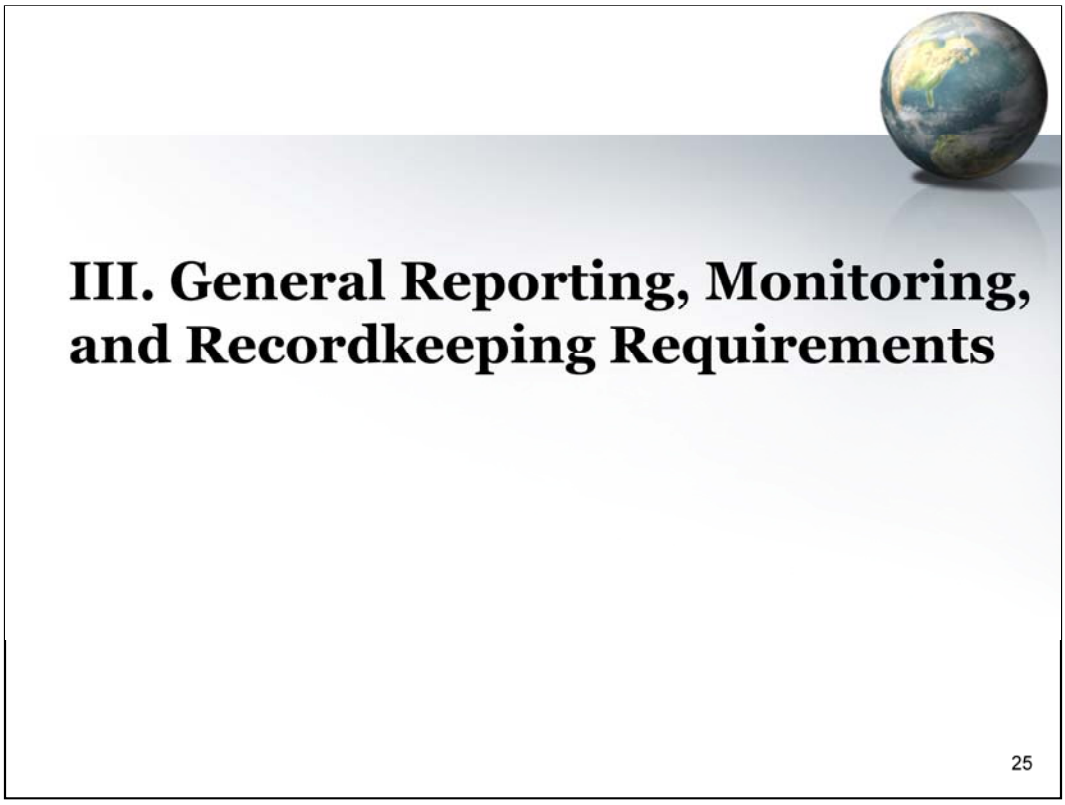


This slide shows an example of Applicability. Under the Greenhouse Gas Reporting Rule, beginning in 2010, a natural gas processing plant with stationary combustion emissions exceeding 25,000 metric tons of CO_2e per year was required to collect their stationary combustion emissions data under subpart C - referred to as reporting year 2010 data or RY 2010 data – and report that data in 2011. This facility would not report under subpart W for reporting year 2010, because subpart W did not apply in 2010. Beginning in 2011, they were required to collect both equipment leak, vented, and flare emissions data under Subpart W and their combustion emissions data under Subpart C – referred to as reporting year 2011 data or RY 2011 data – and to report that data in 2012.



In this example covering emissions from a natural gas transmission station, I would like to stress the point that the emissions threshold applies at the facility level, not to individual source categories or industry segments.

For example, this facility would not need to report reporting year 2010 data, because subpart W did not apply in 2010, and emissions from fuel combustion were less than the 25,000 metric ton/yr CO2e threshold. For reporting year 2011 data, the facility would report under both subpart W and subpart C, because the combined emissions from equipment leaks, vented sources, and stationary combustion sources exceed the emissions threshold. For reporting year 2011 data, the transmission station will report its 2,000 metric tons CO_2e from equipment leak, vented sources and flares under Subpart W and its 24,000 metric tons CO_2e from stationary combustion sources under Subpart C. They will report that data in 2012.



This section covers the general reporting, monitoring, and recordkeeping requirements of the rule.

When you go to part 98, you will find that it has 41 subparts.

Subpart A of part 98 contains general reporting and recordkeeping requirements that apply to all facilities and suppliers subject to the rule. It also spells out the applicability provisions, the reporting schedule, and definitions. The general items that everyone must report and the definitions of subpart A are not repeated in the individual source category sections of the rule, so it is important to look at subpart A as well as at the individual source category subparts.

Subpart A also contains other overarching requirements. For example, there are flow-meter accuracy and calibration provisions in subpart A that apply when specified by an applicable subpart. But the specific types of monitoring equipment needed are defined in the source category subparts.

Subparts C through UU contain specific requirements for each of the source categories covered by the rule. You must follow all of the subparts that pertain to your facility. For example, if your facility produces adipic acid and has fuel combustion sources, you need to read subpart C, general stationary fuel combustion sources, and subpart E, adipic acid production.

Each subpart defines the specific source category it covers and contains the monitoring methods, equations to calculate emissions, and specific data elements to be reported or recorded for that source category.

This slide summarizes the contents of the annual report that apply to all facilities. For details, see section 98.3(c) of subpart A of the rule and the reporting sections of the other subparts that apply to your facility.

Subpart A requires you to report total facility greenhouse gas emissions in units of metric tons of CO_2 equivalent. CO_2 from biomass combustion is reported separately.

You must also report emissions of each gas broken out for each source category at the facility. So, if you have multiple source categories at a facility, you need to report greenhouse gas emissions broken out for each of the categories separately. If a source category emits multiple gases, you report metric tons per year of each gas.

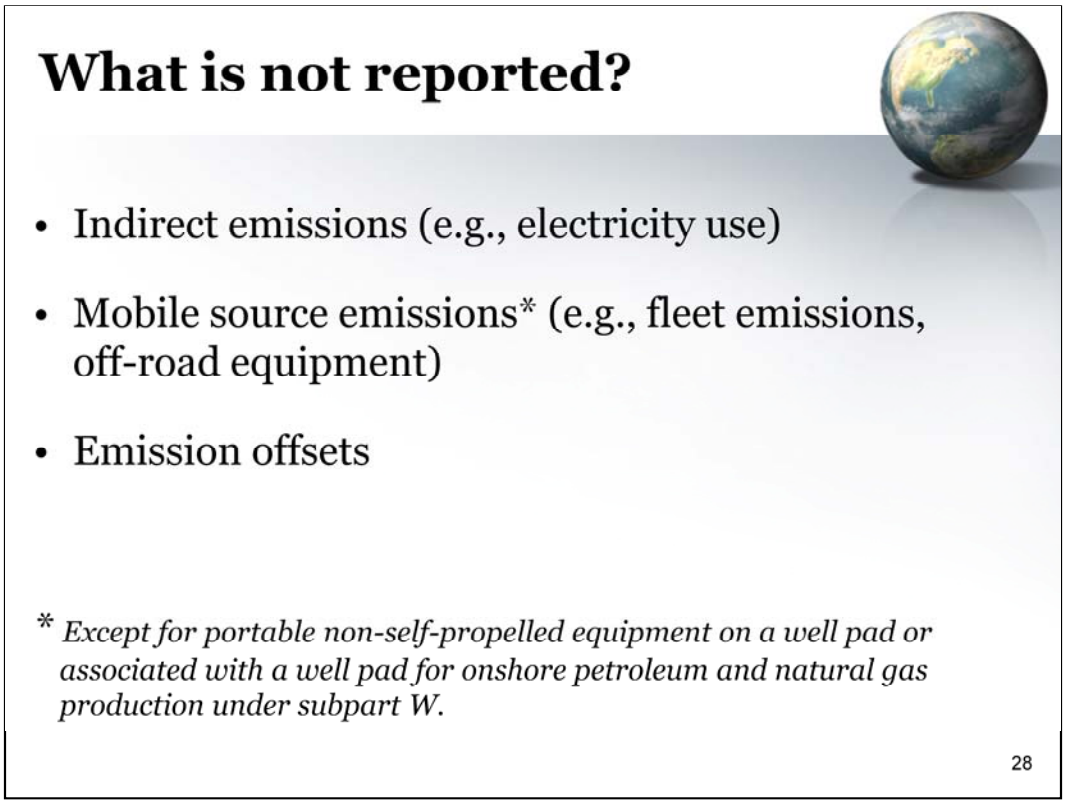
You also report more detailed emissions information—for example, by individual process unit or process line—if required by the applicable subparts. For example, subpart C generally requires you to report stationary combustion emissions for each combustion unit, such as each boiler, but has provisions that will allow many facilities to report combined emissions for groups of combustion units. So, you need to look carefully at the individual source category subparts to understand the specific emission reporting requirements and breakouts for your facility.

Similarly, all reporters must report data needed for emissions verification. The specific data elements to be reported are listed in each subpart. However, EPA has deferred reporting of inputs to emissions equations for a limited period of time, as is explained later.

The bullet referring to a description of best available monitoring methods applies only to the years in which use of best available monitoring methods is allowed by the relevant subpart.

Regarding the bullet on missing data: Because reporting is in total metric tons per year, you need to account for the entire period of operation, even if some data are missing (for example, because a monitor was not working correctly). Each subpart has procedures for estimating emissions during missing data episodes. The annual report needs to identify any data elements for which missing data procedures were used and the total hours the missing data procedures were used.

As noted at the bottom of the slide, if you assess applicability and find you are not subject to the rule,

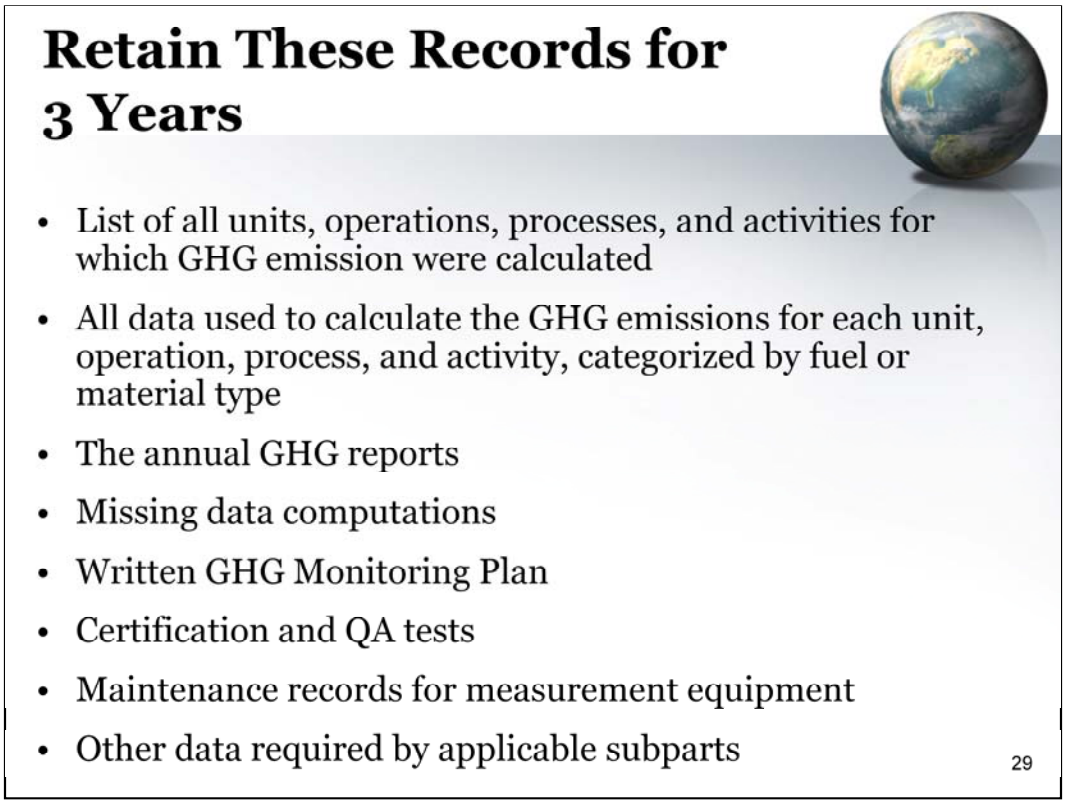


This slide provides some examples of items that might be reported under some other greenhouse gas programs but are not required by this rule.

First, the EPA greenhouse gas reporting rule focuses only on actual emissions released from each facility. Therefore, it does not include indirect emissions. For example, industrial facilities that purchase electricity from the grid do not report on indirect emissions from the generation of the electricity at a utility plant.

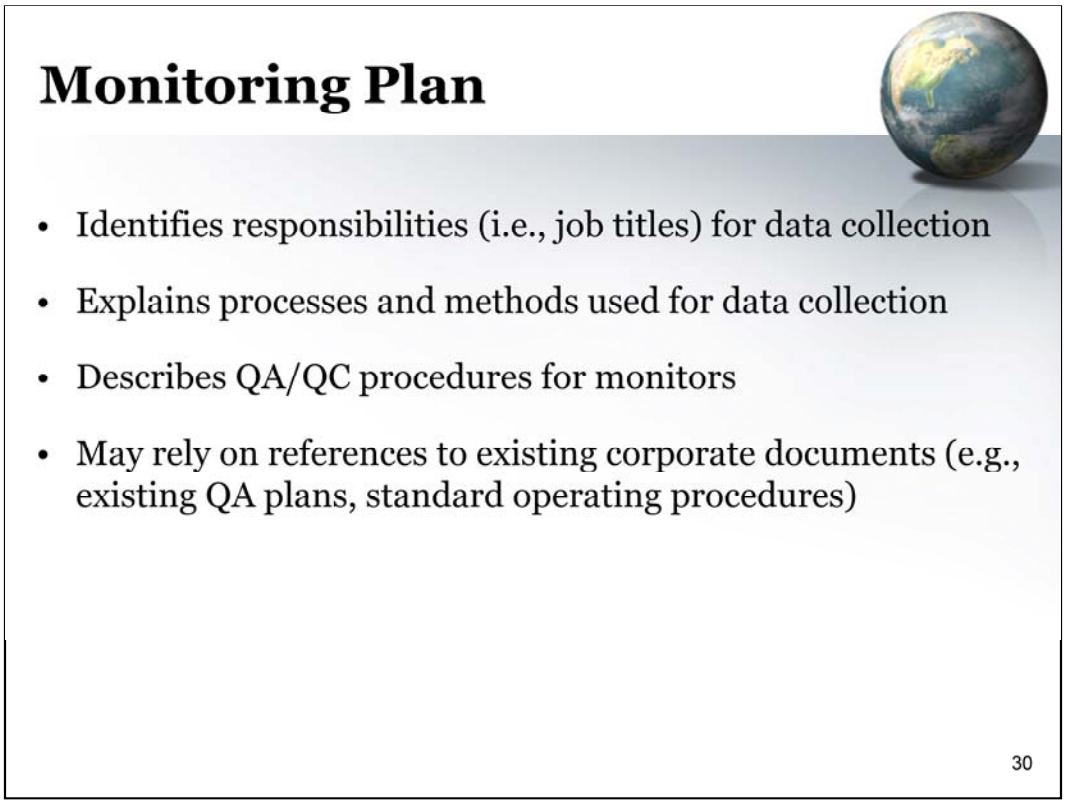
Similarly, facilities do not report emissions from their vehicle fleets. Mobile source emissions are addressed through reporting by fuel producers and by motor vehicle and engine manufacturers. The only exception is that subpart W requires onshore petroleum and natural gas production facilities to report greenhouse gas emissions from portable non-self-propelled equipment associated with a well pad.

Also, if you have offset projects, you do not report them or deduct them from your facility emissions.



This slide lists the types of records all reporters must keep, as specified in subpart A. Additional source category-specific records are contained in subparts C through UU. You are required to keep these records for 3 years.

You can keep records in either hard copy or electronic format, either on site or off site, as long as the records can be quickly made available to EPA if EPA requests them for inspection and review.

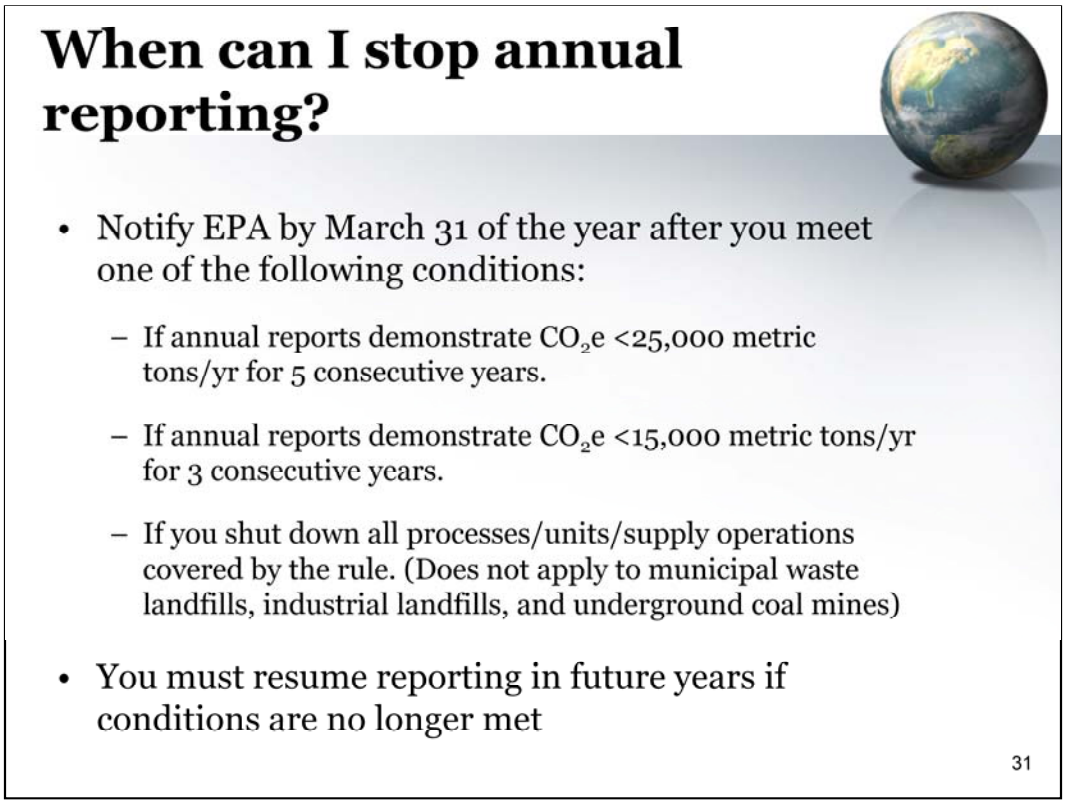


One of the recordkeeping requirements is a monitoring plan. Each facility or supplier must prepare a written plan describing the processes and methods you are using to collect the data elements required by the rule and who is responsible for data collection. You keep the monitoring plan as a record, and it does not need to be submitted unless EPA requests it for inspection.

The monitoring plan includes the first three items listed on this slide, which are described in a little more detail in section 98.3(g) of subpart A of the rule.

The plan can refer to and rely on existing documents that many facilities already have, such as standard operating procedures, documents, or existing QA plans that contain the required information. This reduces the effort to prepare the plan and avoids duplicative documents for your facility.

Also note that if you change or improve your monitoring and QA/QC procedures over time, you need to update your monitoring plan accordingly. For example, if you use best available monitoring methods, the Monitoring Plan must document these methods and then be revised when you comply with the monitoring requirements of the applicable subparts.



Once you have started to report under the rule, there are three “exit ramps” that allow you to stop reporting. These provisions to stop reporting apply to all facilities and suppliers, regardless of whether applicability was triggered by a threshold or “all-in” source category.

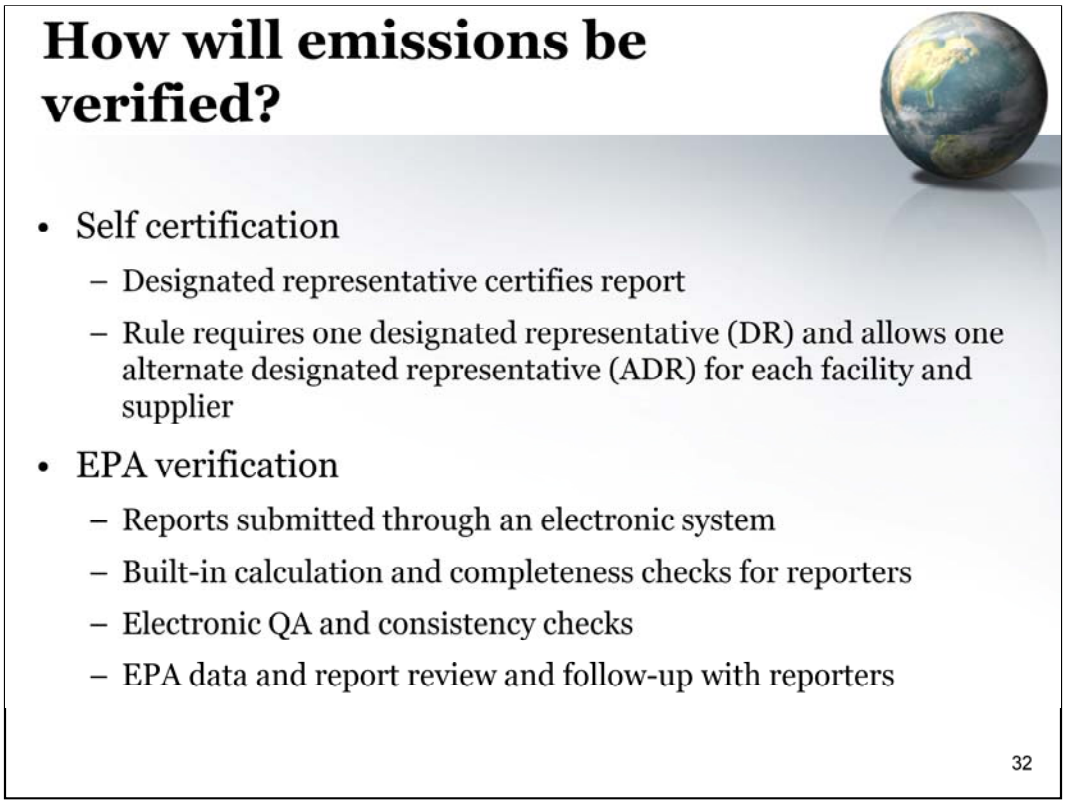
To stop reporting, you must meet one of the three conditions listed here, and you must also notify EPA that you intend to stop reporting.

The first way to stop reporting is if the annual reports you submitted under the rule show that emissions were less than 25,000 metric tons of CO_2 equivalent per year for 5 years. In this case, you need to keep records of emissions for each of the 5 years (rather than the normal 3-year record retention).

Second, you can stop reporting if you emit less than 15,000 metric tons of CO_2 equivalent per year for 3 years.

Third, you can stop reporting if you close all of the processes covered by the rule. However, this third provision does not apply to municipal solid waste landfills, industrial waste landfills, or underground coal mines because these sources continue to emit methane for many years after they close.

If you reopen closed processes or start emitting more than 25,000 metric tons of CO_2 equivalent per year in a future year, you must resume reporting.

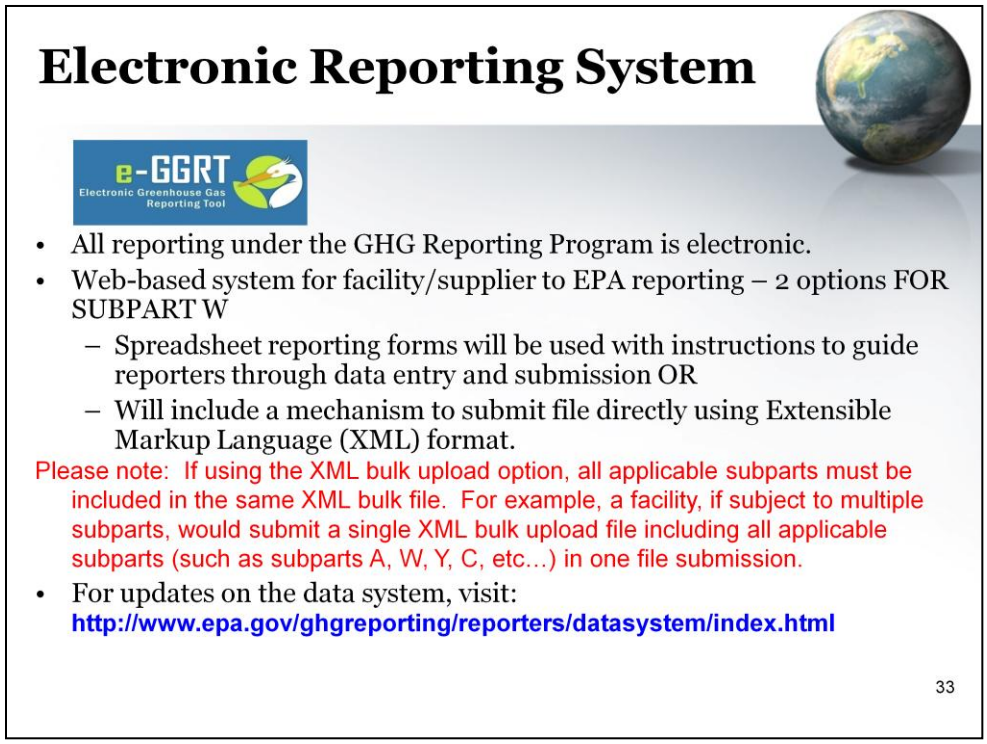


Emissions reports are verified through self-certification by the reporter and EPA verification.

Each facility or supplier must have one and only one designated representative who certifies the report. Each can also have one alternate designated representative. While the designated representative does not need to be an employee at the reporting facility, the DR must be appointed by the owners and operators of the facility by a legally binding agreement.

The data that are reported will be used by EPA to verify the emissions, using a combination of electronic data quality assurance checks, and review of individual reports. The electronic reporting system—described on the next couple slides—will have built-in range checks and completeness checks at the point of data entry by the reporter. EPA will also conduct validation using algorithms and statistical analysis to identify potential errors and will review individual reports.

EPA intends to communicate with the reporter if it finds probable errors in reviewing the reports. If the report is determined to contain a “substantive error,” the reporter would then follow the procedures in the rule to correct and resubmit the report.



All reporting under the GHG Reporting Program will be electronic, and reporters will be required to use EPA's Electronic Greenhouse Gas Reporting Tool (e-GGRT)

E-GGRT Is a Web-based system for submitting reports:

e-GGRT will handle user and facility registration for GHGRP .

Subpart W reporters will have 2 options for submitting annual reports to EPA:

1) Microsoft Excel spreadsheets (the spreadsheets have instructions embedded within them that will guide reporters through data entry process).

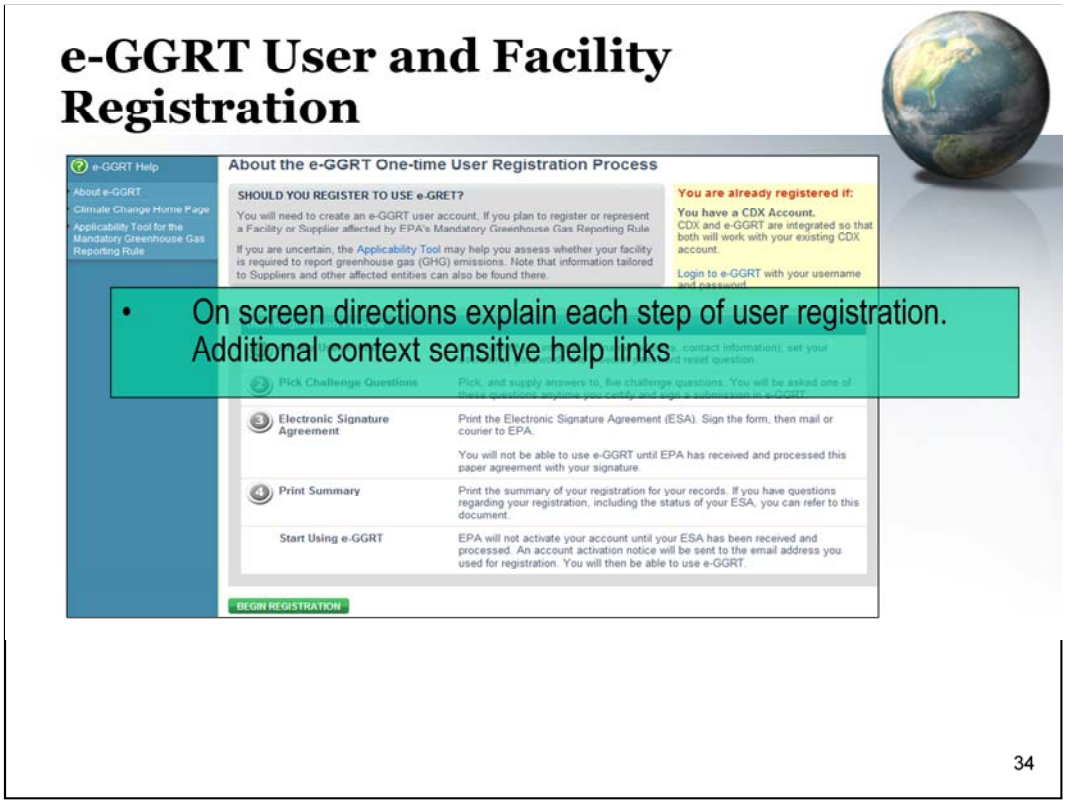
OR

2) Reporters can submit XML file directly to e-GGRT.

Reporters would download XML schema from EPA website, use schema to design data export from in-house data system, then upload completed XML file into e-GGRT.

Please note: If using the XML bulk upload option, all applicable subparts must be included in the same XML bulk file. For example, a facility, if subject to multiple subparts, would submit a single XML bulk upload file including all applicable subparts (such as subparts A, W, Y, C, etc) in one file submission.

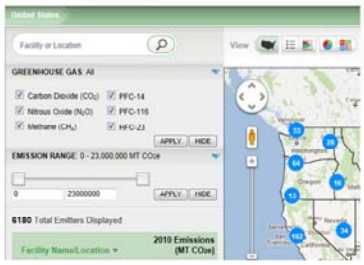
For updates on the data system, reporters should refer to the website listed on this page



You must also use e-GGRT to register your facility or supplier and the designated representative prior to the first reporting date. e-GGRT contains on-screen directions and additional context-sensitive help links to assist first-time users. The registration deadline for new subpart W reporters is July 30, 2012.

GHG Data Publication

- The data reported to the GHGRP is available on the website. (See EPA's GHG data website at http://ghgdata.epa.gov.)
- EPA will publish only data that is not CBI
  - CBI data would only be published in aggregated form to shield sensitive information
- The GHGRP data publication tool will
  - Display facilities on a map
  - Create charts, graphs, and lists
  - Download data
  - Leverage social media



EPA GHG data website landing page.

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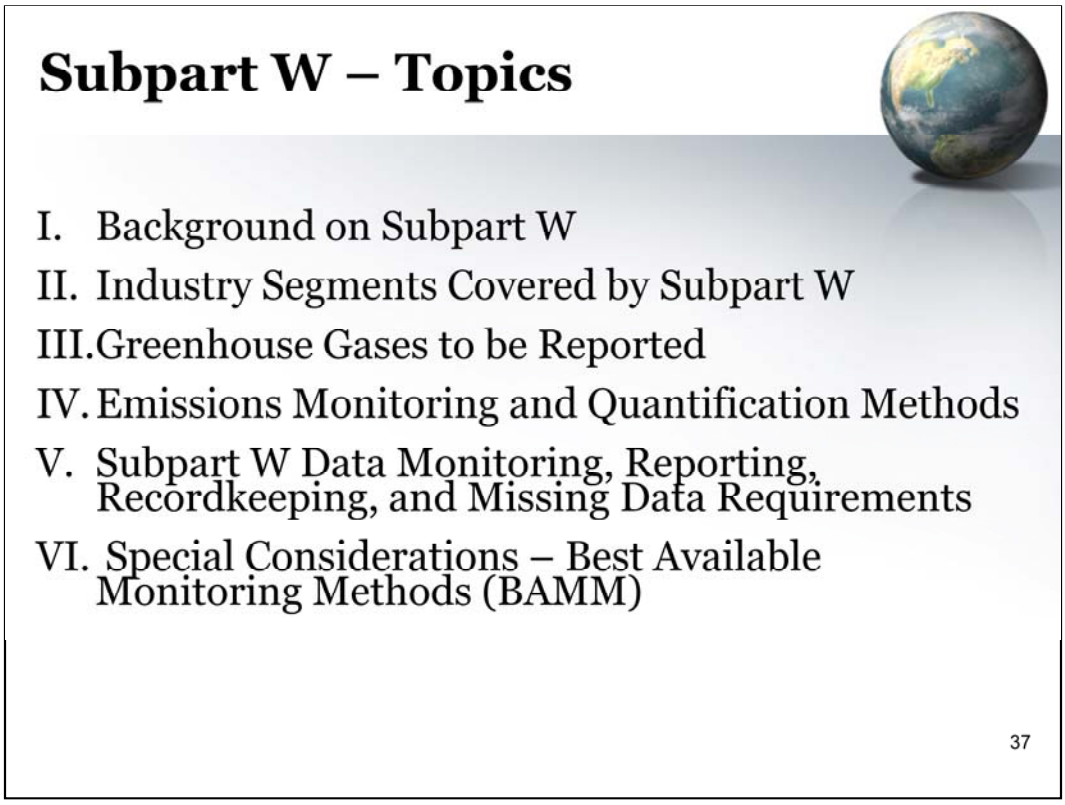
EPA will publish all GHG emissions data collected through the Greenhouse Gas Reporting Program that is not Confidential Business Information (CBI) on the web. CBI data would only be published in aggregated form to shield sensitive information.

EPA's GHGRP data publication tool, which can be accessed through the home page of the GHGRP website, will display reporting facilities on national or regional maps and will allow users to search and download data. Also, the system is being designed to leverage social media.

This concludes the section of the presentation on the Background of the GHGRP and General Rule Requirements. Next, we will discuss Subpart W.

Subpart W
Petroleum and Natural Gas Systems



This slide shows you the topics that we will cover in the subpart W section of this training session.

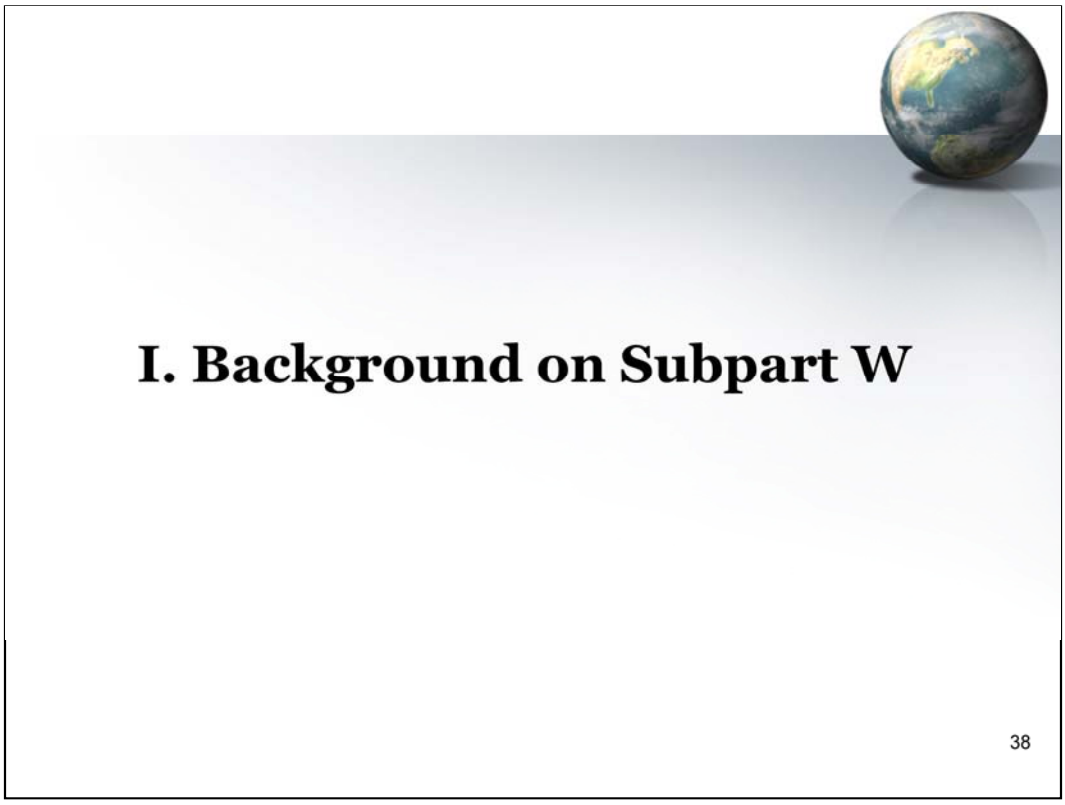
-First we will go over background information on Subpart W.

-Followed by a review of the industry segments covered under subpart W

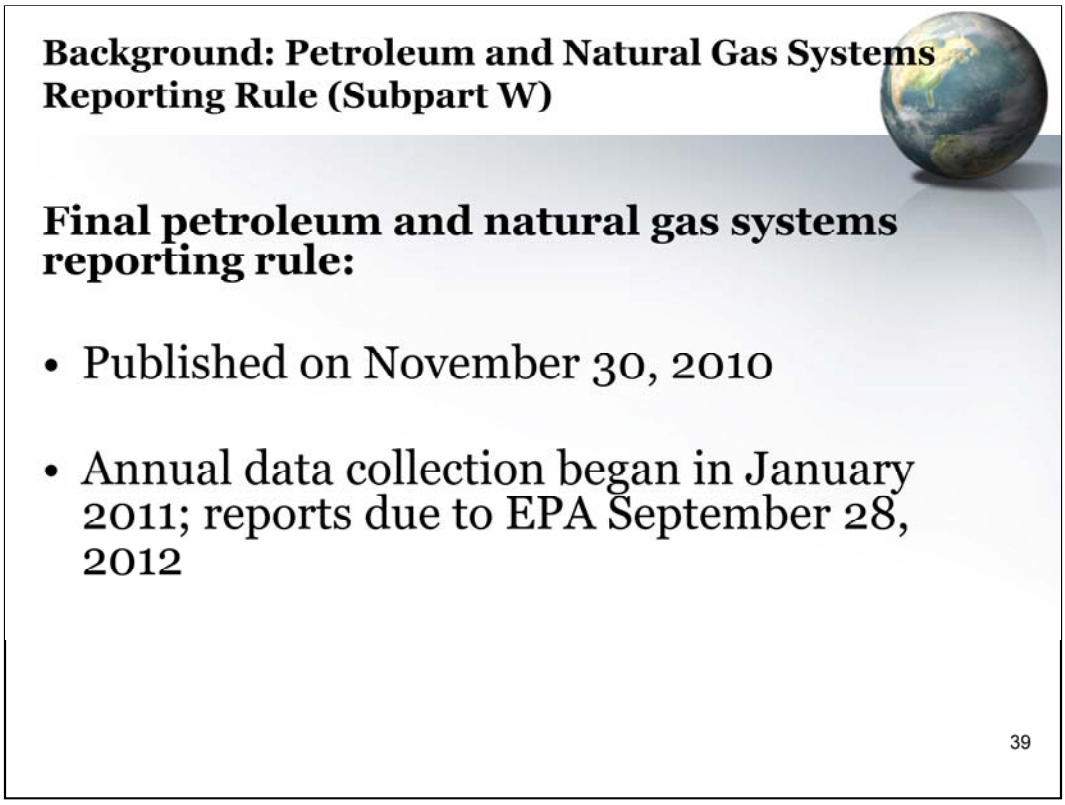
- A review of the greenhouse gases to be reported

-The data monitoring, reporting, recordkeeping, and missing data requirements,

-Special considerations – Best Available Monitoring Methods (BAMM)



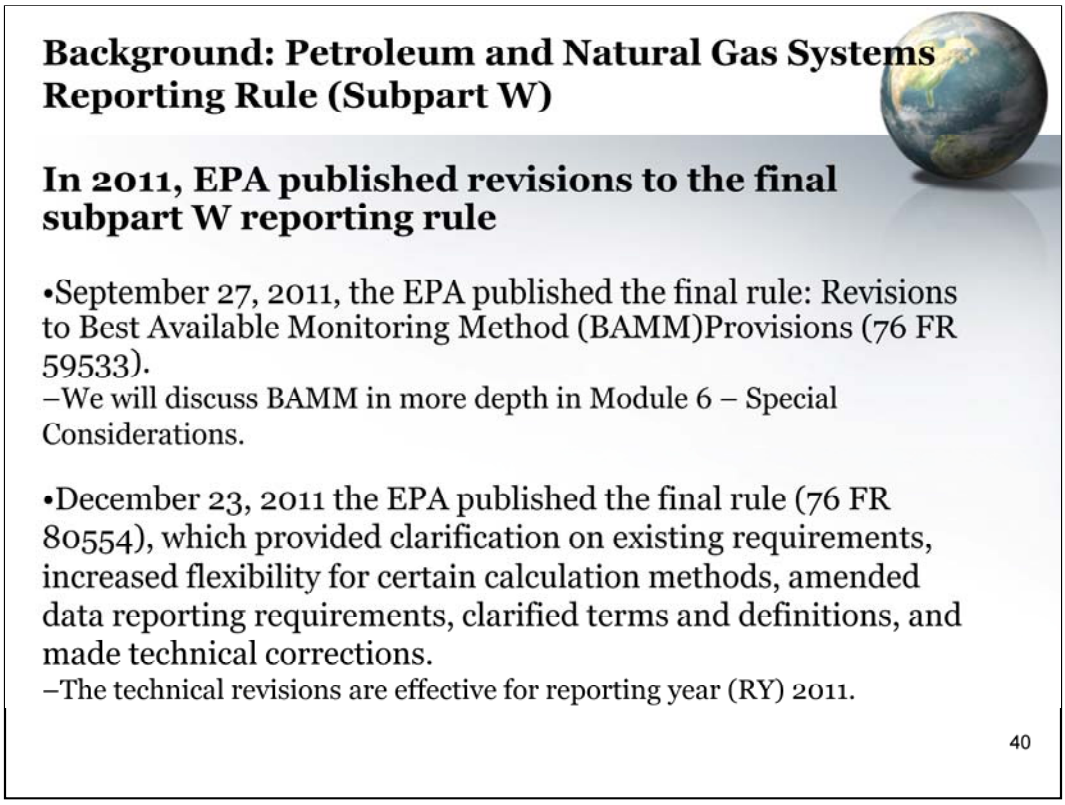
The first topic to discuss will be the Background on Subpart W.



Background Information

The final rule for subpart W was signed on November 8, 2010 and published in the Federal Register November 30, 2010.

The annual data collection for subpart W began January 1, 2011, with the first reports due to EPA by September 28, 2012.



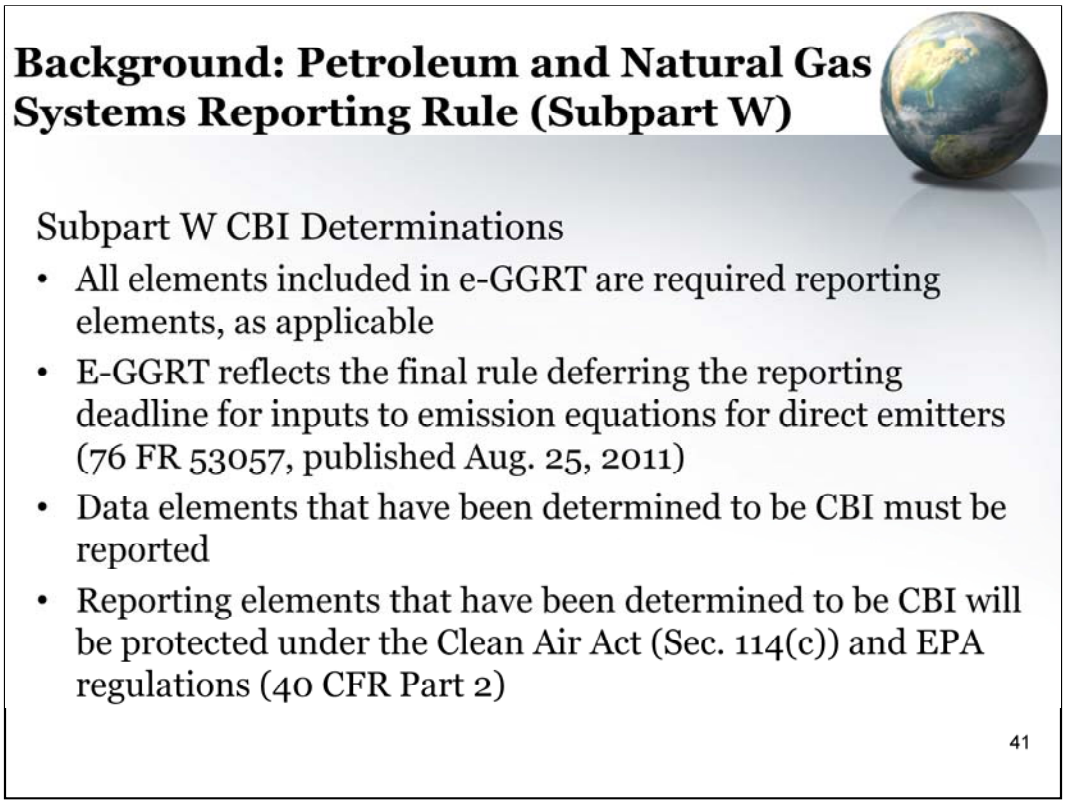
On September 27, 2011, the EPA published the final rule: Revisions to Best Available Monitoring Method (BAMM)Provisions (76 FR 59533).
We will discuss BAMM in more depth when we discuss the 6th Subpart W topic – Special Considerations.

On December 23, 2011, EPA also issued a final rule that amended specific provisions in subparts A and W to correct technical and editorial errors and address issues identified as a result of questions or concerns received from reporters.

These amendments do not change the overall requirements, but improve clarity and consistency across the calculation, monitoring and data reporting requirements.

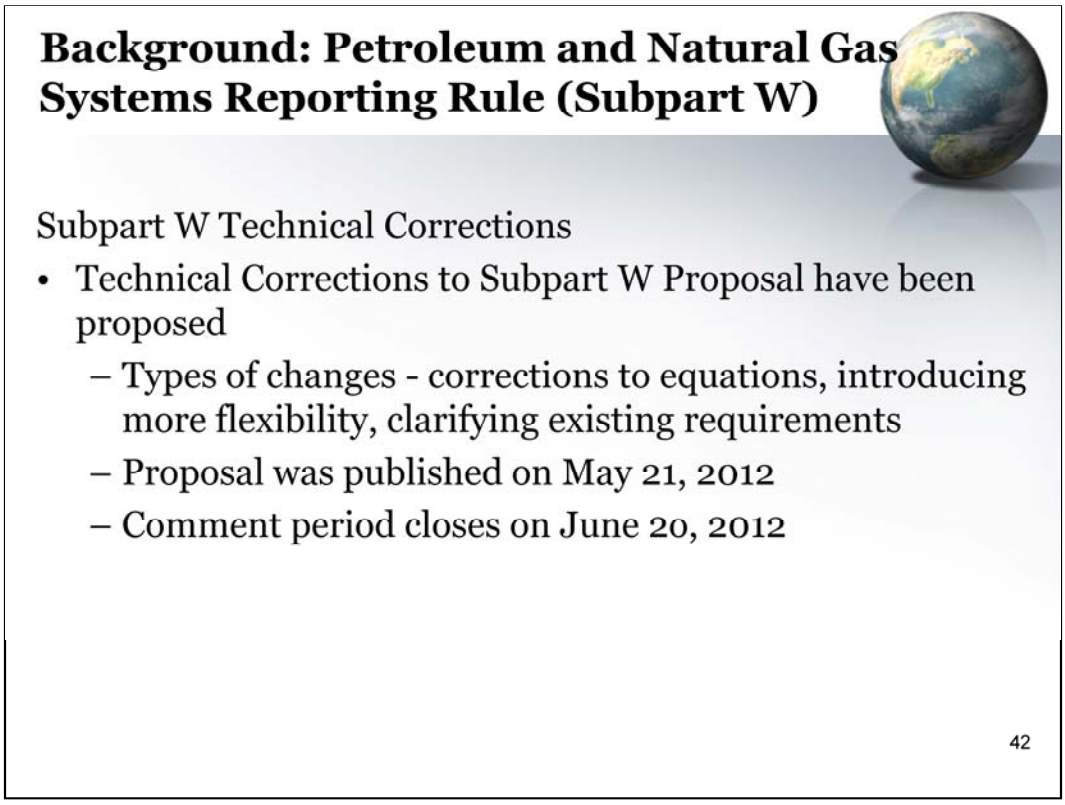
These amendments will assist facilities with meeting reporting requirements, and provide greater specificity on applicability and reporting thresholds. They maintain the accuracy of the data while, in some cases, reduce the burden for those entities that report under these subparts.

The technical revisions are effective for reporting year 2011, because they provided additional clarification and did not change the type of information collected or materially affect how emissions are calculated.



EPA has finalized a rule that defers the deadline for most data elements used as inputs to emissions equations in subpart W. See 76 FR 53057 (published August 25, 2011). In accordance with the rule, e-GGRT is not currently collecting these inputs to emissions equations. EPA has proposed to defer the remaining data elements used as inputs to emission equations in subpart W. See 77 FR 11039 (published February 24, 2012).

E-GGRT currently reflects the proposed rule deferring the deadline for reporting the remaining inputs to emission equations for subpart W so that you would be able to visually see how those proposed changes affect the current data reporting requirements, should they be finalized as proposed. E-GGRT will be updated to reflect the final rule once the proposal if finalized.



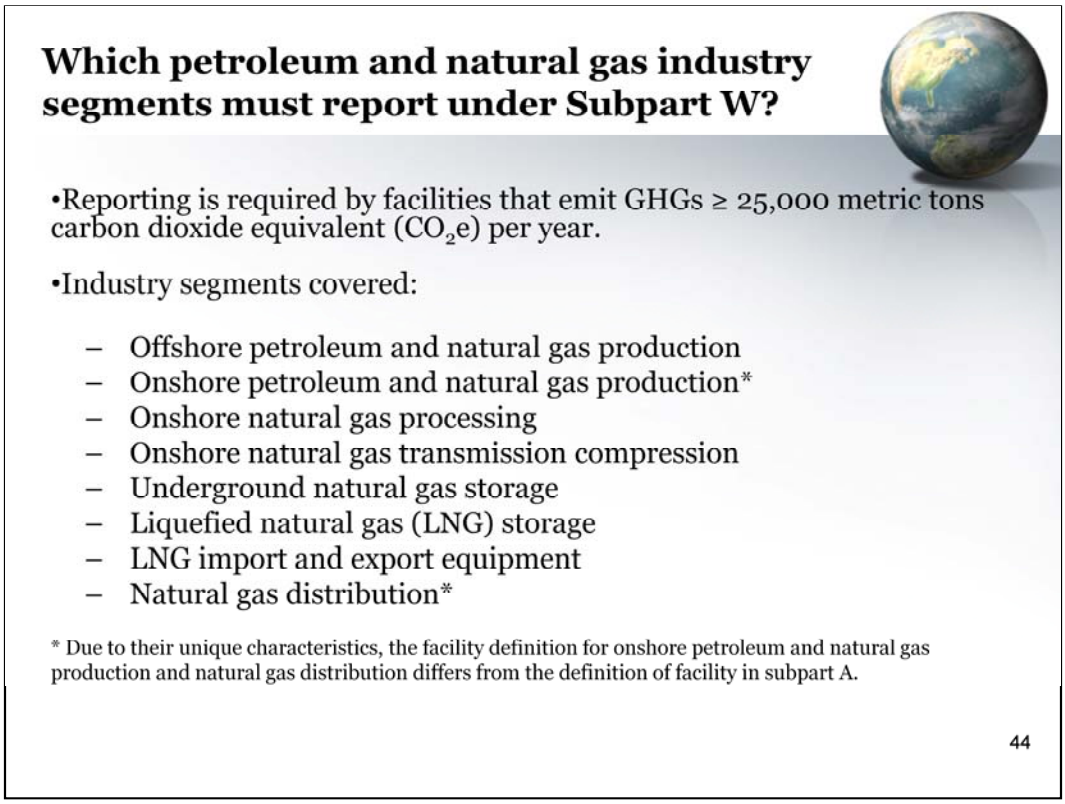
EPA identified technical corrections, and a Technical Corrections Proposal has been published.

The types of changes are: corrections to equations, introducing more flexibility, and clarifying existing requirements

Proposal was published on May 21, 2012.

Comment period closes on June 20, 2012.

Our next topic to discuss will be the industry segments that are covered by Subpart W.



The petroleum and natural gas source category of Part 98 is broken up into 8 key industry segments under which facilities would be required to report to EPA, if in any calendar year they exceed the combined 25,000 metric ton threshold of carbon dioxide equivalent as outlined in 98.2(a)(2) of the general provisions. The segments are as follows:

-Offshore petroleum and natural gas production (sometimes referred to as “offshore production” in this training)

-Onshore petroleum and natural gas production (sometimes referred to as “onshore production” in this training)

-Onshore natural gas processing

-Onshore natural gas transmission compression

-Underground natural gas storage

-Liquefied natural gas storage – also known as LNG storage

-LNG import and export equipment

-Natural gas distribution facilities owned or operated by Local Distribution Companies (LDCs)

As noted earlier, the onshore petroleum and natural gas production industry segment and the natural gas distribution industry segment each have a definition of facility that differs from how the term facility is defined in the general provisions. And we will cover that in the upcoming slides.

Offshore Petroleum and Natural Gas Production

Offshore Petroleum and Natural Gas Production: Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

Offshore production facilities under BOEM jurisdiction shall report the same annual emissions as calculated and reported by BOEM in data collection and emissions estimation study published by BOEM reference in 30 CFR 250.302 through 304 (GOADS).

Offshore production facilities that are not under BOEM jurisdiction shall use the monitoring methods and calculation methodologies published by BOEM referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

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The first industry segment covered under subpart W is offshore petroleum and natural gas production. As you can see from this slide, we clipped the industry segment definition from the rule, in section 98.230. This industry segment is defined with the following key points in mind:
a)The facility includes the primary platform structure plus any “secondary platform structures connected” to the primary platform; all are cumulatively considered one facility
b)Offshore facilities in both State and Federal waters are covered under this industry segment
c)This industry segment does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

Offshore reporters can be broadly grouped into two types;
The first type includes facilities in the Federal Gulf of Mexico that already report to the Bureau of Ocean Energy Management (also known as BOEM) under the Gulfwide Offshore Activity Data System (also known as GOADS) program. These facilities will report emissions from their “most recent BOEM reported emissions data”

The second type includes facilities that are not already reporting to the BOEM GOADS program. These facilities “shall use monitoring methods and calculation methodologies published by BOEM“

For the 2011 reporting year (RY2011), offshore reporters – both GOADS and non-GOADS – will use the 2008 GOADS study as the latest published study for reporting emissions to EPA.

Onshore Petroleum and Natural Gas Production

***Onshore Petroleum and Natural Gas Production*:** Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO_2 or natural gas injection, and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

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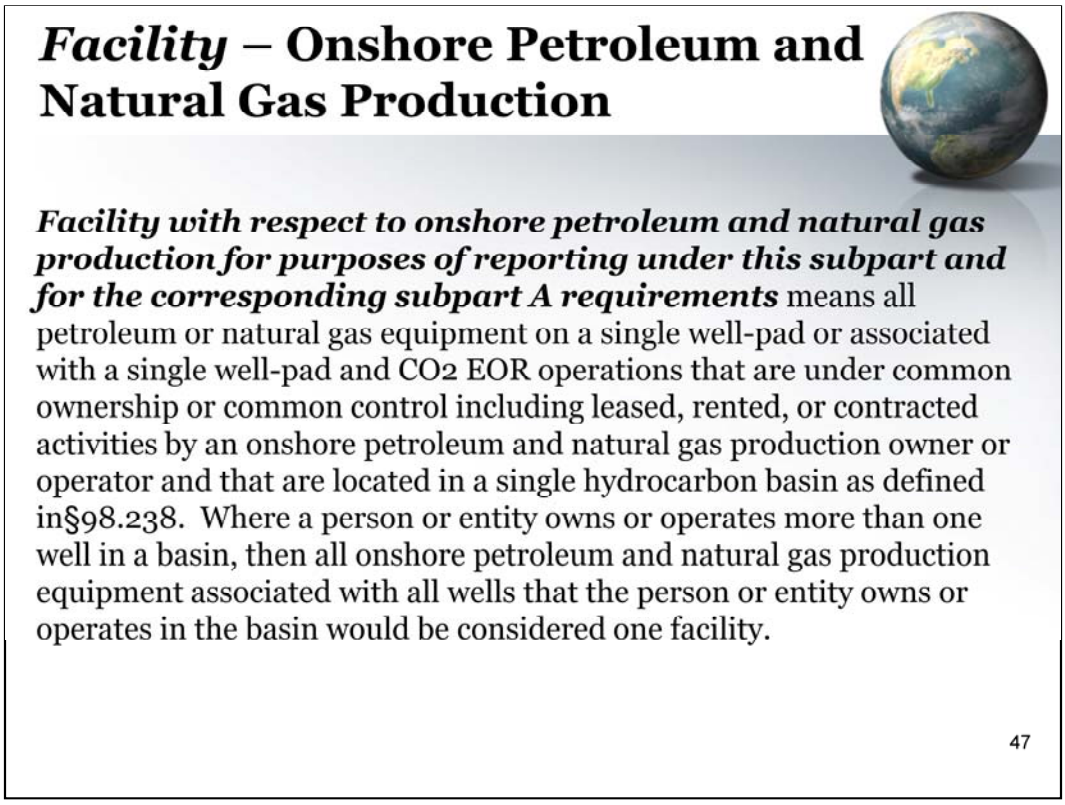
The second industry segment covered under subpart W is the onshore production industry segment. This slide includes a clippet from the rule text in 98.230 which defines this industry segment. A few points to consider are;
a)The Onshore Production facility includes “equipment on a single well pad or associated with a single well pad”
b)activity associated with leased, rented, or contracted equipment are covered under this industry segment

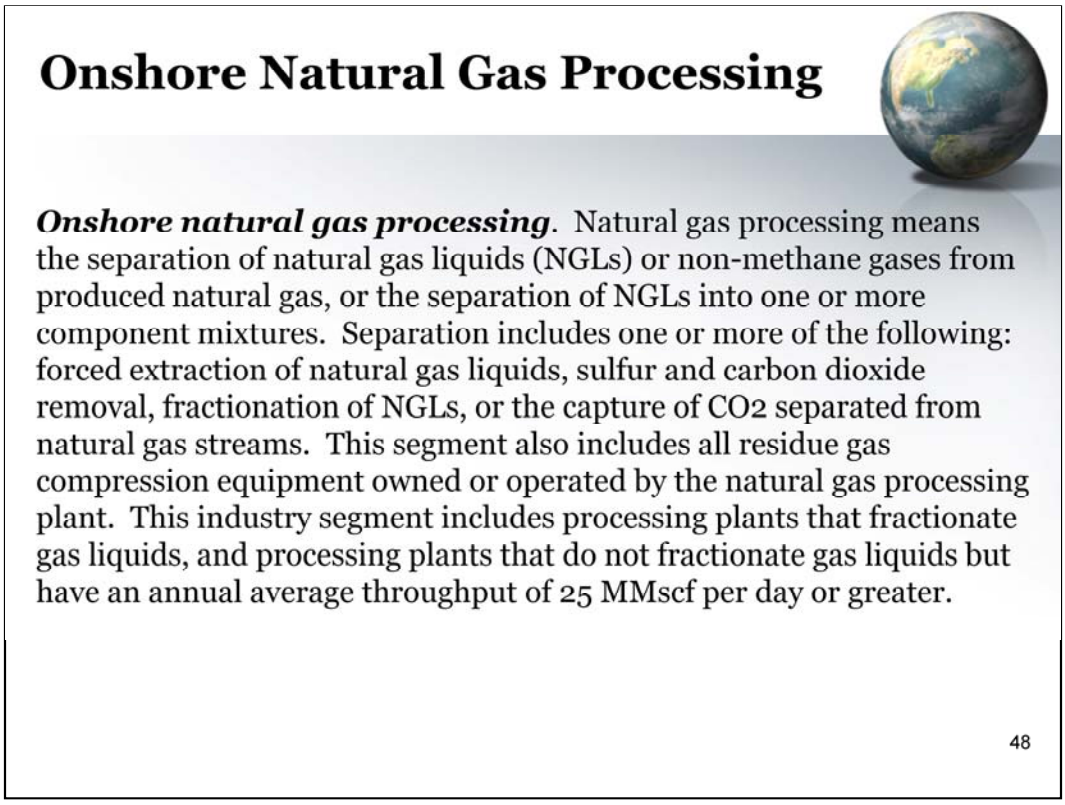
One item of note is that subpart W defines a facility differently than the General provisions of Part 98 for the onshore production industry segment due to its unique characteristics. And we will cover that definition in the next slide.



As noted earlier in this training, the Onshore Petroleum and Natural Gas Industry Segment has a definition of "facility" that differs from the subpart A definition. This was done in order to ensure that the reporting delineation was clear, to avoid double counting, and ensure appropriate emissions coverage.

The facility here is defined as being all petroleum or natural gas equipment on a single well pad or associated with a single well pad and CO_2 enhanced oil recovery (EOR) operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

For the purposes of applicability determination Onshore production facilities must consider only those emissions sources listed in 98.232(c) in the rule when determining whether they meet the threshold.



The third industry segment covered under subpart W is onshore natural gas processing.

Please note: This industry segment consists of all processing facilities that fractionate, and all processing facilities that do not fractionate that have a throughput of 25 MMscf (million standard cubic feet) per day or greater.

Onshore Natural Gas Transmission Compression

Onshore natural gas transmission compression. Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

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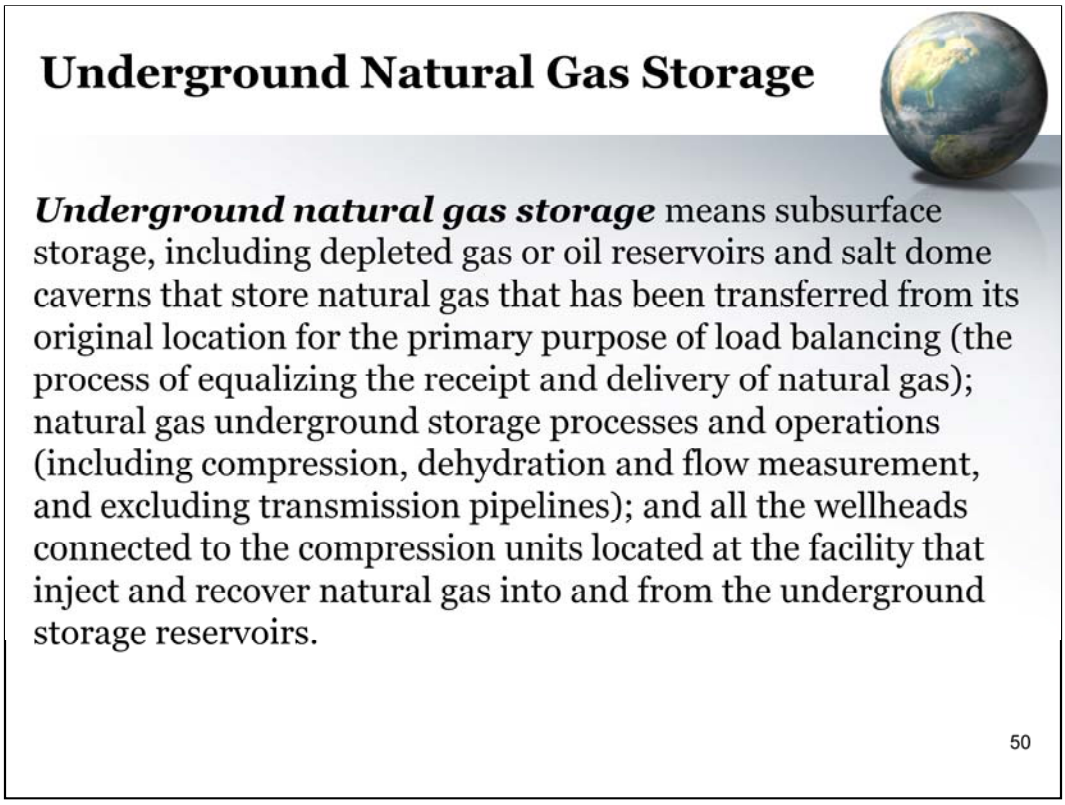
The fourth industry segment covered under subpart W is the natural gas transmission compression industry segment. This industry segment is comprised of facilities that compress gas to move it along transmission pipelines. A few items to keep in mind about this particular industry segment are that:

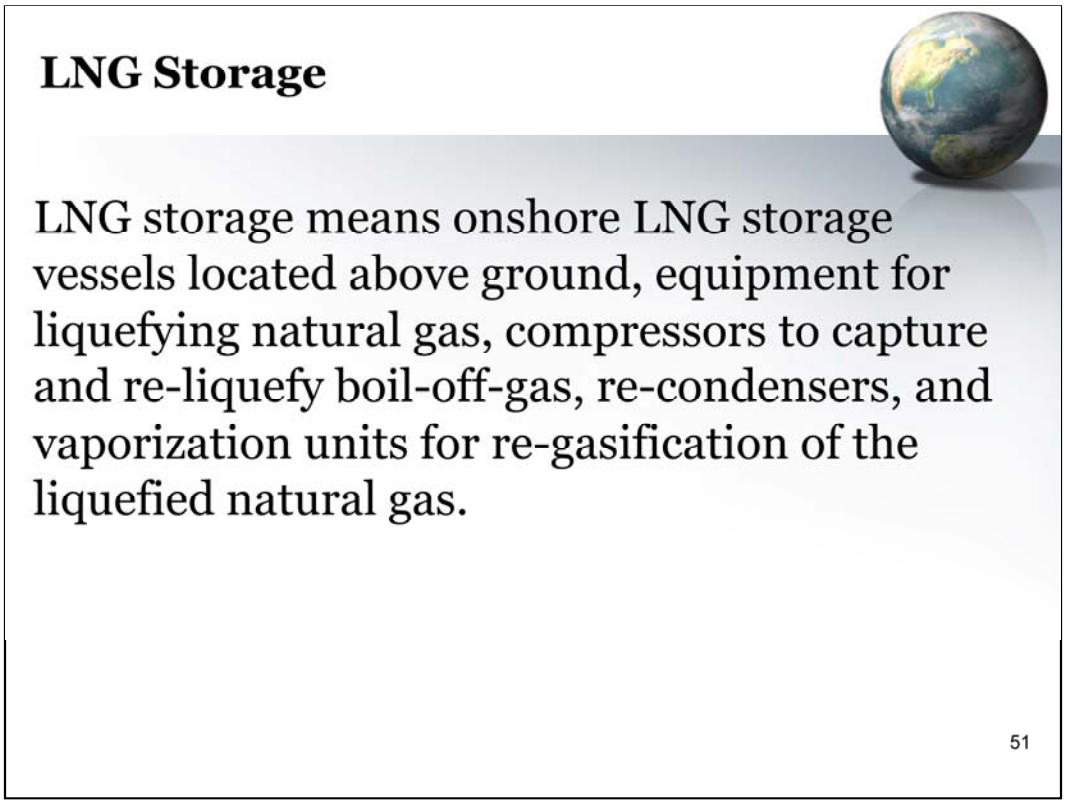
-All compression equipment, liquid separation equipment, dehydration equipment, and storage tanks are considered part of the facility.

-This segment does not include processing facility residue gas compression equipment or gathering lines or boosting stations.

-Residue gas compression that is located at onshore natural gas processing plants are included in that segment and are not part of the transmission compression industry segment.

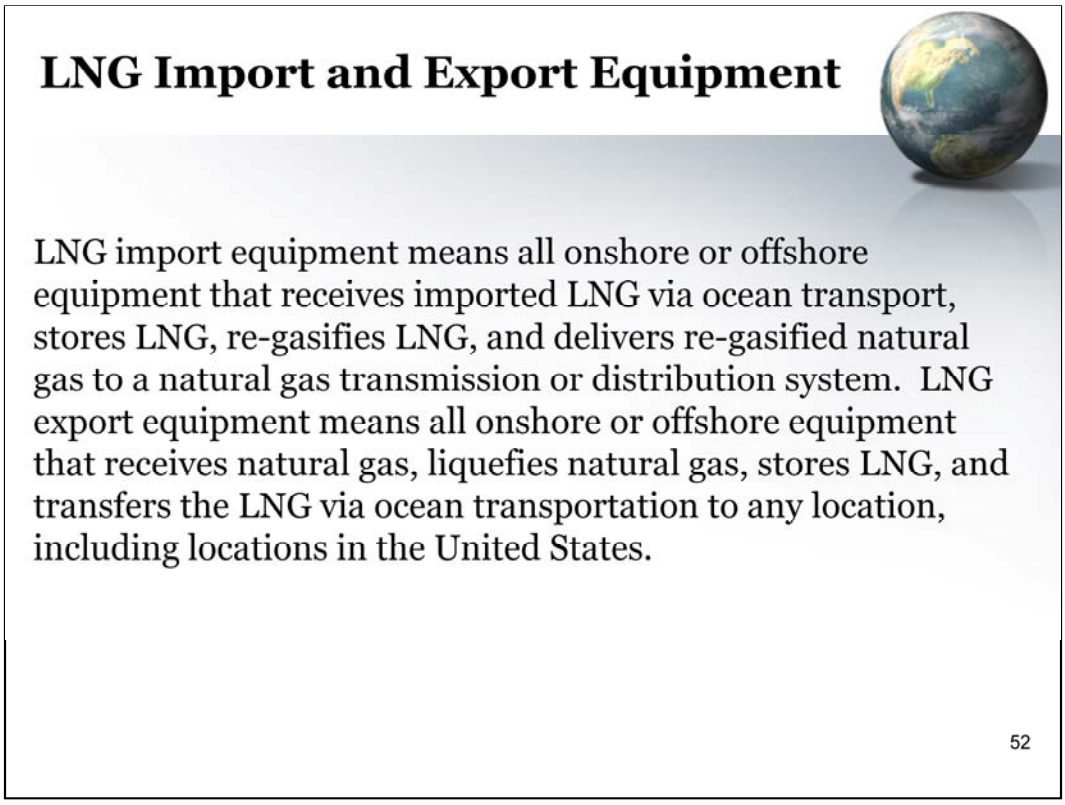


Underground storage facilities, which is the fifth industry segment under W, cover processes and operations used to store and load balance natural gas in subsurface storage locations. This industry segment also includes any wellheads that inject and recover natural gas and are connected to the facility.



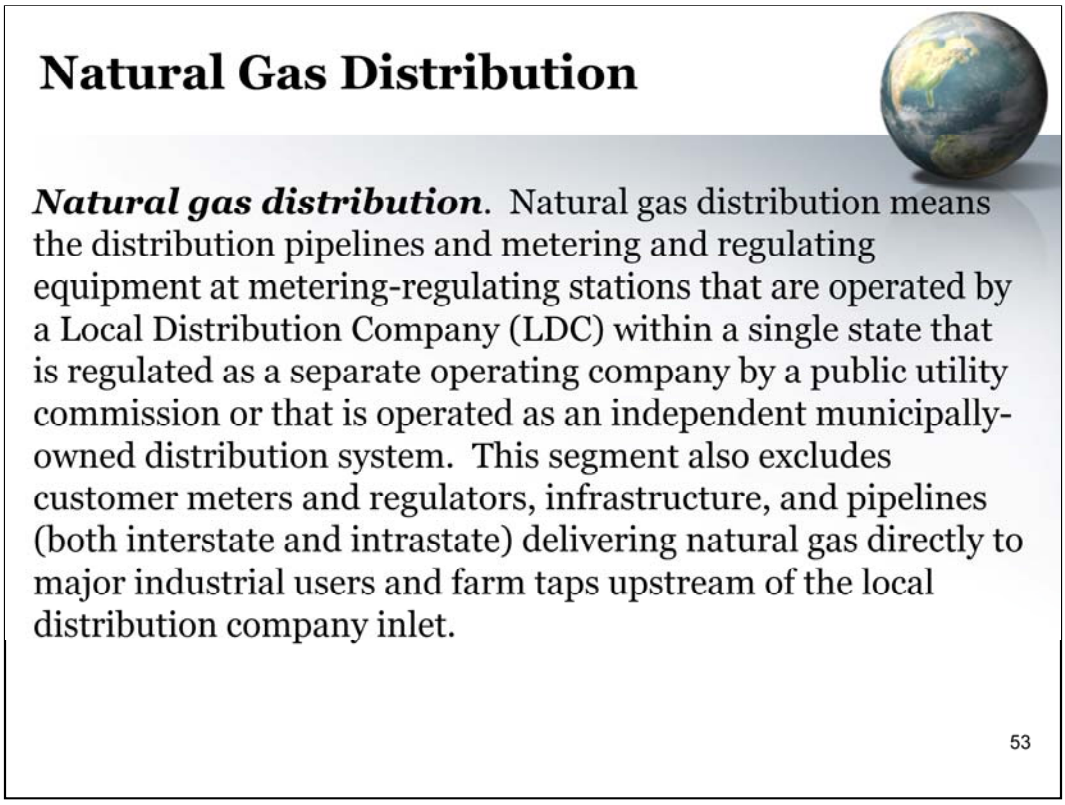
The sixth industry segments under subpart W – LNG storage. The LNG storage industry segment covers processes that store and liquefy natural gas in above ground storage tanks.

1. Liquefied natural gas (LNG) storage facility means an above ground onshore LNG storage vessel and all associated equipment.
2. Equipment subject to reporting by LNG storage facilities includes equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquid natural gas.



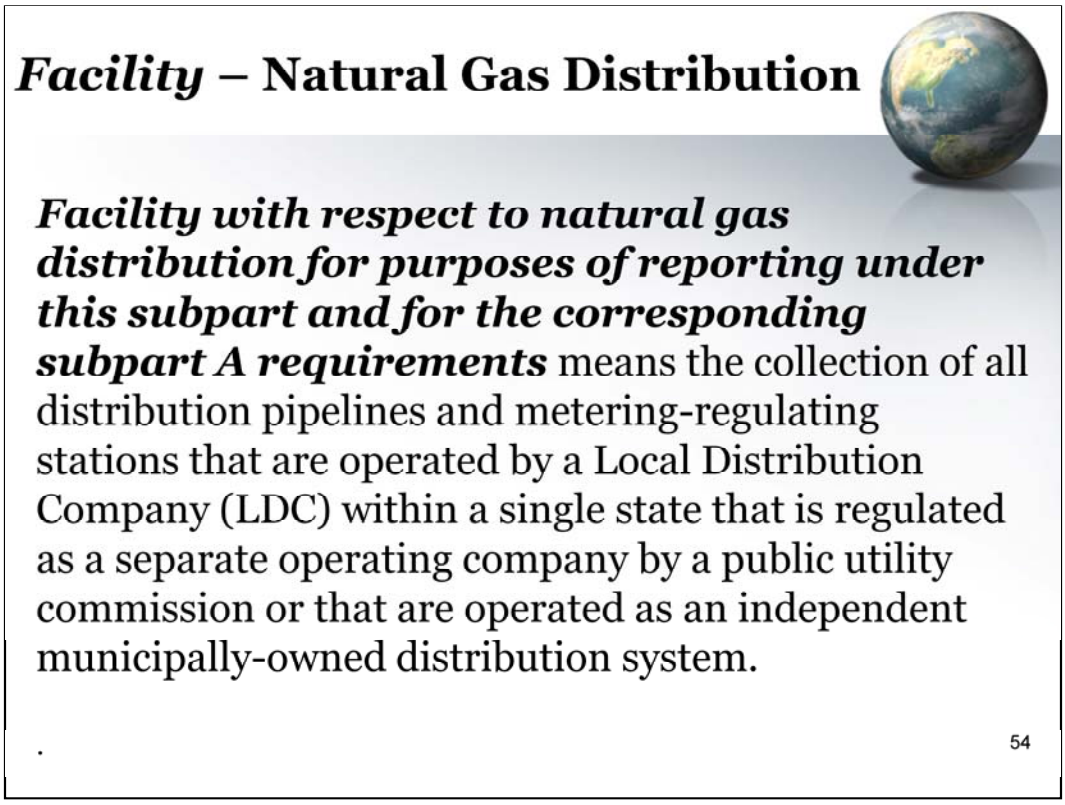
The seventh industry segment under subpart W is LNG import and/or export equipment. The LNG import/export industry segment covers equipment that receive imported LNG via ocean transport, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to natural gas transmission or distribution systems.

1. LNG import/export equipment means all onshore or offshore equipment that receives or delivers LNG from or to foreign and United States locations via ocean transportation.
2. Equipment subject to reporting includes storage of LNG, re-gasification of LNG and liquefaction of natural gas.



The eighth industry segment covered under subpart W is the natural gas distribution industry segment. A key point to keep in mind in regards to this industry segment is:

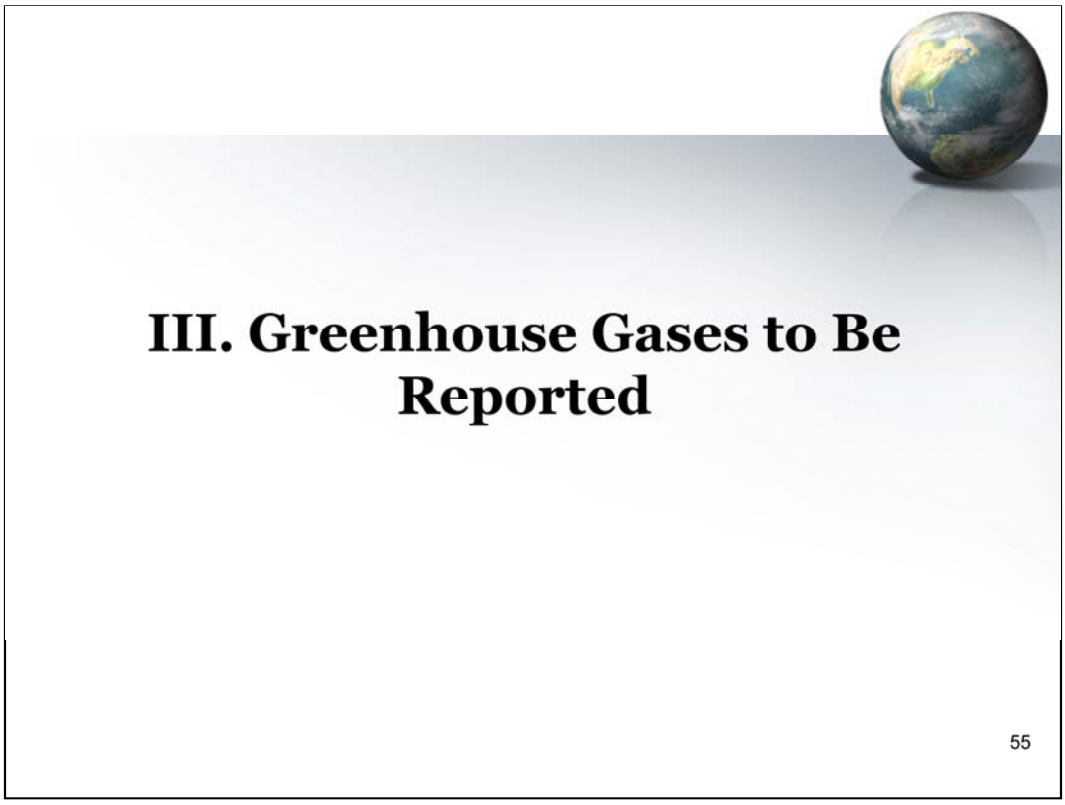
1. Equipment operated by an LDC that is not subject to reporting includes, in addition to all customer meters; all pipelines, both interstate and intrastate pipelines delivering natural gas directly to major industrial users; and all “farm taps” upstream of LDC inlet.



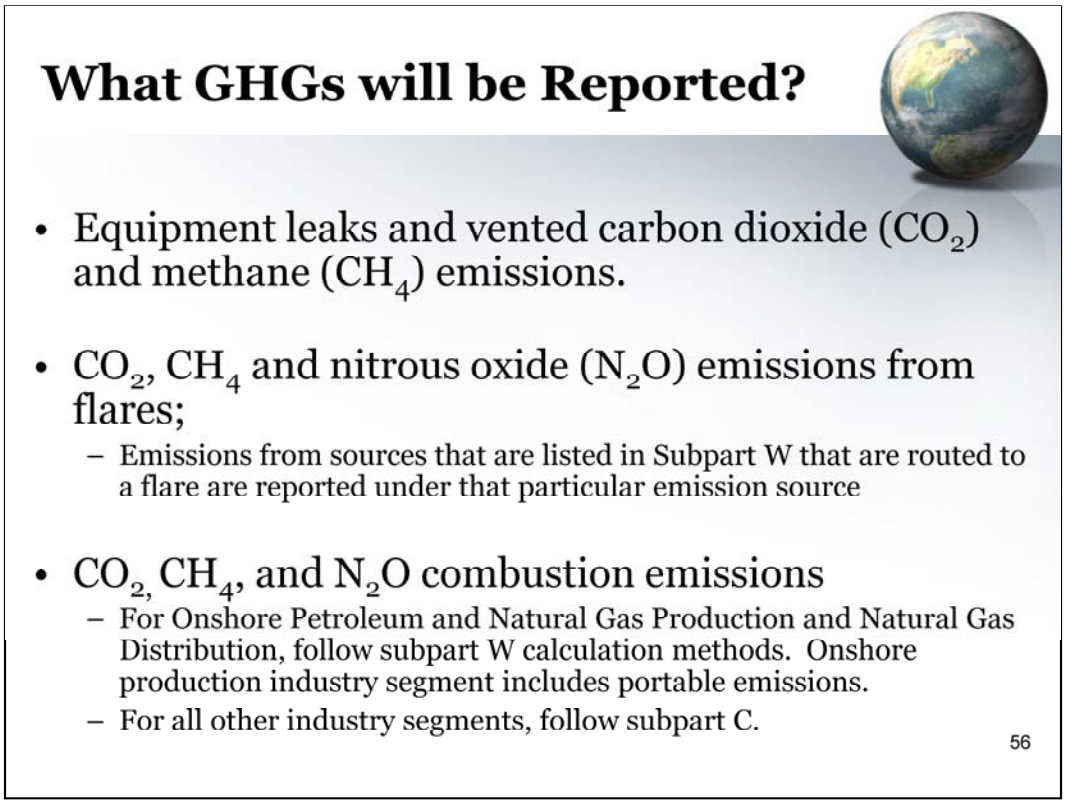
As noted earlier in this training, similar to the Onshore Production Industry Segment, the Natural Gas Distribution Industry Segment has a definition of "facility" that differs from the subpart A definition. This was done in order to ensure that the reporting delineation was clear, to avoid double counting, and ensure appropriate emissions coverage.

The facility here is defined as being the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single site that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

For the purposes of applicability determination Natural gas distribution facilities consider only those emissions sources listed in 98.232(i) in the rule when determining whether they meet the threshold.



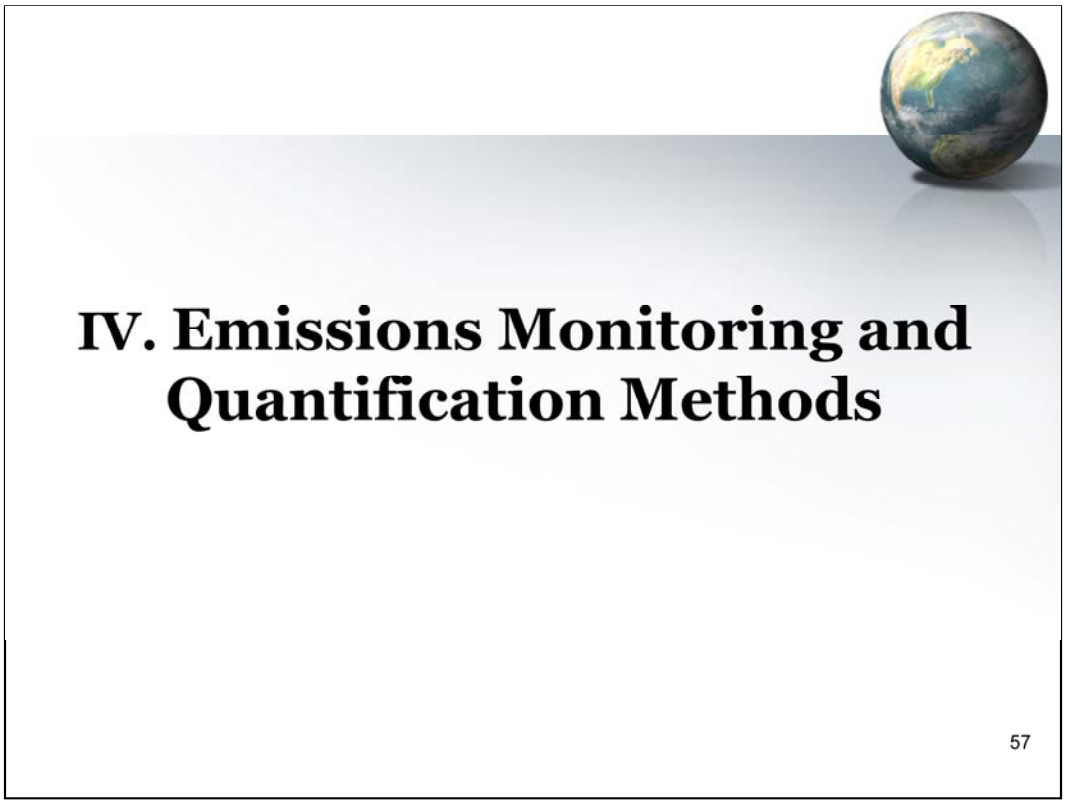
Now we review the greenhouse gases to be reported under subpart W.



Under subpart W, facilities must report annual methane and carbon dioxide emissions from equipment leaks and venting.

In addition, facilities must report emissions of carbon dioxide, methane and nitrous oxide from flaring. Please note that there are certain emissions sources in subpart W that require reporting of flare emissions under that source. For example, for the transmission storage tank emissions source in subpart W, the annual GHG emissions from these tanks are calculated using methods that include the estimation of emissions that were sent to flares.

Finally, both the onshore production and natural gas distribution industry segment will report their carbon dioxide, methane, and nitrous oxide combustion emissions under subpart W. Other industry segments report stationary combustion emissions under subpart C.



At this stage in the training we will cover emissions monitoring and quantification methods as prescribed under subpart W.

How will emissions be calculated?

Calculations may have a choice of methods or a combination of the listed methods

Source Type	Engineering Estimates	Direct Measurement	Leak Detection and Leaker Emission Factor	Equipment Count and Population Emission Factor
Natural gas pneumatic device venting				X
Natural gas driven pneumatic pump venting				X
Well venting for liquids unloading	X	X		
Gas well venting during completions without hydraulic fracturing	X			
Gas well venting during completions with hydraulic fracturing	X	X		
Gas well venting during workovers without hydraulic fracturing	X			
Gas well venting during workovers with hydraulic fracturing	X	X		
Onshore production storage tanks	X			X
Transmission storage tanks		X		

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This table lays out the monitoring methods for each emissions source covered under subpart W. For some sources there are multiple methods that can be used to determine annual GHG emissions. Appendix A of this slide set has a table which outlines the emissions source that are to be reported under a given industry segment.

1)Pneumatic devices are to be monitored using population emissions factors and device counts. In the case of the onshore production industry segment, EPA has allowed for counting of pneumatic devices over a three year period.

2)Emissions from Pneumatic pumps are calculated using component counts together with population emissions factors which are given in the associate tables in subpart W.

3)Emissions from well venting for liquids unloading are calculated using one of three calculation methodologies in the rule. And these three methodologies involve the use of engineering estimates and direct measurement for quantifying emissions.

4)Emissions from gas well venting during well completions without hydraulic fracturing (and this is also the same for Gas well venting during well workovers without hydraulic fracturing) are determined using an engineering equation.

5)Emissions resulting from gas well venting during completions and workovers with hydraulic fracturing are calculated using an engineering estimate to determine the annual GHG emissions, and direct measurement to determine the gas flow rate for venting which is an input to the engineering equation.

6)For the onshore production storage tanks, emissions are determined using any of 5 calculation methodologies outlined in the rule. These calculation methodologies include the use of a software program or standard method to estimate emissions or using analysis or default compositions of the oil and estimate emissions assuming all the CH_4 and CO_2 are vented emissions. Population counts and an emission factor may be used if production is less than 10 barrels per day.

7)Emissions resulting from compressor scrubber dump valve leakage at transmissions storage tanks are calculated using direct measurement.

How will emissions be calculated?

Calculations may have a choice of methods or a combination of the listed methods

Source Type	Engineering Estimates	Direct Measurement	Leak Detection and Leaker Emission Factor	Equipment Count and Population Emission Factor
Reciprocating compressor venting	X	X		X
Well testing venting and flaring	X			
Associated gas venting and flaring	X			
Dehydrator vent stacks	X			X
EOR injection pump blowdown	X			
Acid gas removal vent stack	X	X		
EOR hydrocarbon liquids dissolved CO_2		X		
Centrifugal compressor venting	X	X		X
Other emissions from equipment leaks			X [2,3,4,5,6,7]	X [1,4,5,6,7]

Note: Applicable only to the industry segments enumerated as follows: 1. Production 2. Processing 3. Transmission Compression 4. Underground storage 5. LNG storage 6. LNG Import and Export 7. Distribution. Sources with multiple methods indicate options for monitoring.

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1) Emissions from reciprocating compressor rod packing venting are calculated using direct measurement and engineering equations. Annual measurements must be conducted for each reciprocating compressor in the mode in which it is found during the annual measurement except for those reciprocating compressors that fall under the onshore production industry segment. The onshore production segment will determine emissions from reciprocating compressors using population emissions factor as outlined in the rule.
2) Emissions resulting from well testing venting and flaring are calculated using an engineering equation.
3) Associated gas venting and flaring, emissions are calculated using an engineering equation also. To note, for both the well testing venting and flaring emissions source and the associated gas venting and flaring emissions source, the gas to oil ratio of the hydrocarbon production for each well can be determined using available data.
4) For dehydrator vent stacks, emissions are calculated using either engineering equations or software simulation program that meets the qualifications outlined in the rule. For dehydrator vent stacks, EPA has provided an equipment threshold of 0.4 million standard cubic feet per day throughput (mmscf/day). Any dehydrator with a throughput less than the equipment threshold requires the use of emissions factor to estimate emissions; units with throughput greater than the equipment threshold require the use of process simulation to estimate emissions.
5) Emissions from EOR pump blowdowns are estimated using the number of blowdowns during a year, the volume of blowdown equipment chambers and the fraction of CO2 in the injection gas.
6) Acid gas removal vent emissions are calculated using one of four methods. Those methods include using an engineering equation or direct measurement such as the use of CEMS, vent stack monitoring, or mass balance approaches to determine emissions.
7) Enhanced Oil Recovery or EOR hydrocarbon liquids dissolved carbon dioxide emissions are determined using direct measurement, and in this case, annual samples.
8) Emissions from centrifugal compressor venting are conducted by taking an annual measurement of each compressor in the mode in which the compressor is found during that annual measurement. However, a measurement must be conducted of each compressor in the not operating, depressurized mode at least once every three calendar years. For the onshore production industry segment, emissions are calculated using standard emission factors and a count of compressors.
9) Emissions from other equipment leaks are to be monitored using either population emissions factors or leak detection and leaker emissions factor as appropriate. Please see section 98.233 (q) and (r) of the rule for further details.

How will emissions be calculated?

Calculations may have a choice of methods or a combination of the listed methods

Source Type	Engineering Estimates	Direct Measurement	Leak Detection and Leaker Emission Factor	Equipment Count and Population Emission Factor
Blowdown vent stacks	X			
Flare stacks emissions	X	X		
Onshore petroleum, natural gas production, and natural gas distribution combustion emissions	X	X		
Above ground M-R station and T-D transfer station equipment leaks			X	X
Below ground MR station and T-D transfer station equipment leaks				X
Pipeline main equipment leaks				X
Service line equipment leaks				X

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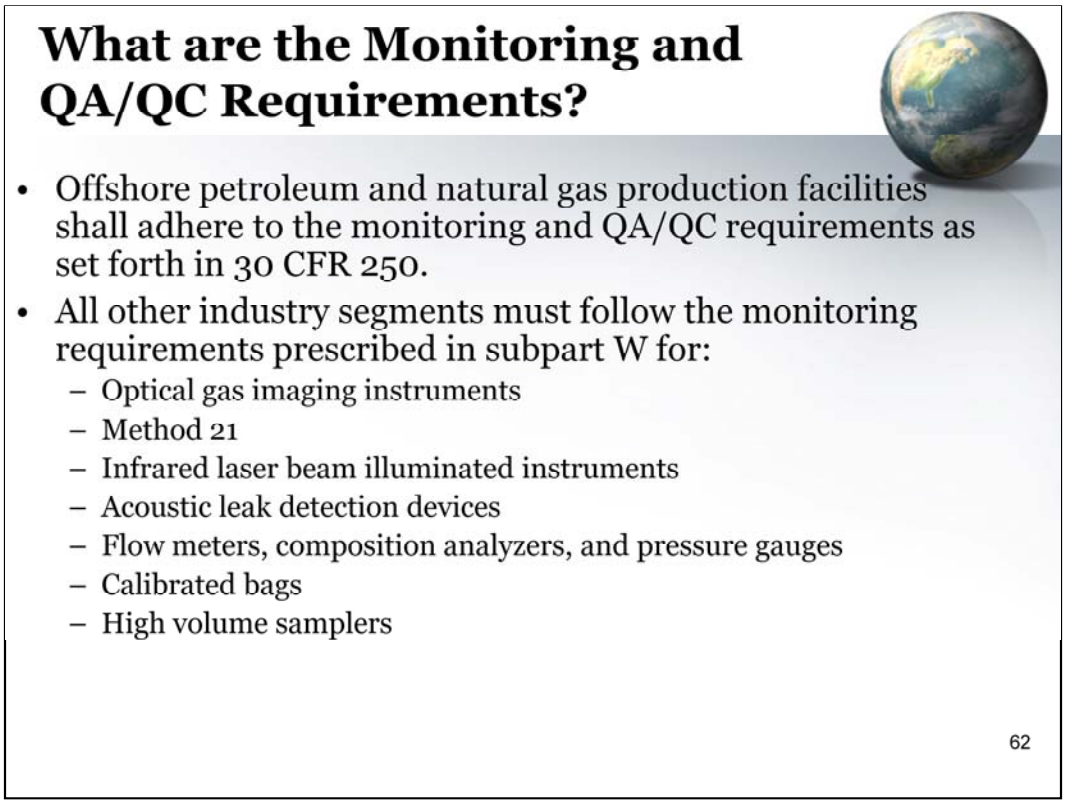
1) Blowdown vent stack emissions are calculated by using an engineering equation. The equation uses the number of blowdowns and the physical volume of blowdown equipment chambers between isolation valves.
2) Flare stack emissions are determined using engineering equations and direct measurement.
3) Combustion emissions are determined using direct measurement and engineering equations. Stationary combustion emissions for all industry segments covered under subpart W except for the onshore production and natural gas distribution segments are to be reported under subpart C. Onshore production and natural gas distribution industry segments will monitor and report combustion emissions under subpart W. Portable combustion emissions are to be reported from the onshore production segment only.
4) Emissions resulting from equipment leaks at above ground meter-regulating and transfer distribution stations are determined using a calculated emission factor based on leak detection and leaker emission factors, and the count of meter/regulator runs at MR and TD stations.
5) Below ground meter and regulator station, pipeline mains, and service line equipment leaks are determined using population emissions factors.

Now we will cover the data monitoring, reporting, recordkeeping, and missing data requirements covered under subpart W.



Facilities under the offshore production industry segment must follow the requirements as set forth in the GOADS program conducted by BOEM.

Other segments of the industry shall conduct monitoring and QA/QC of all equipment used for leak detection and leak measurement as required in section 98.234 of the rule.

The monitoring and QA/QC requirements of subpart W are outlined in the rule and apply to the following :

•optical gas imaging instruments

•method 21

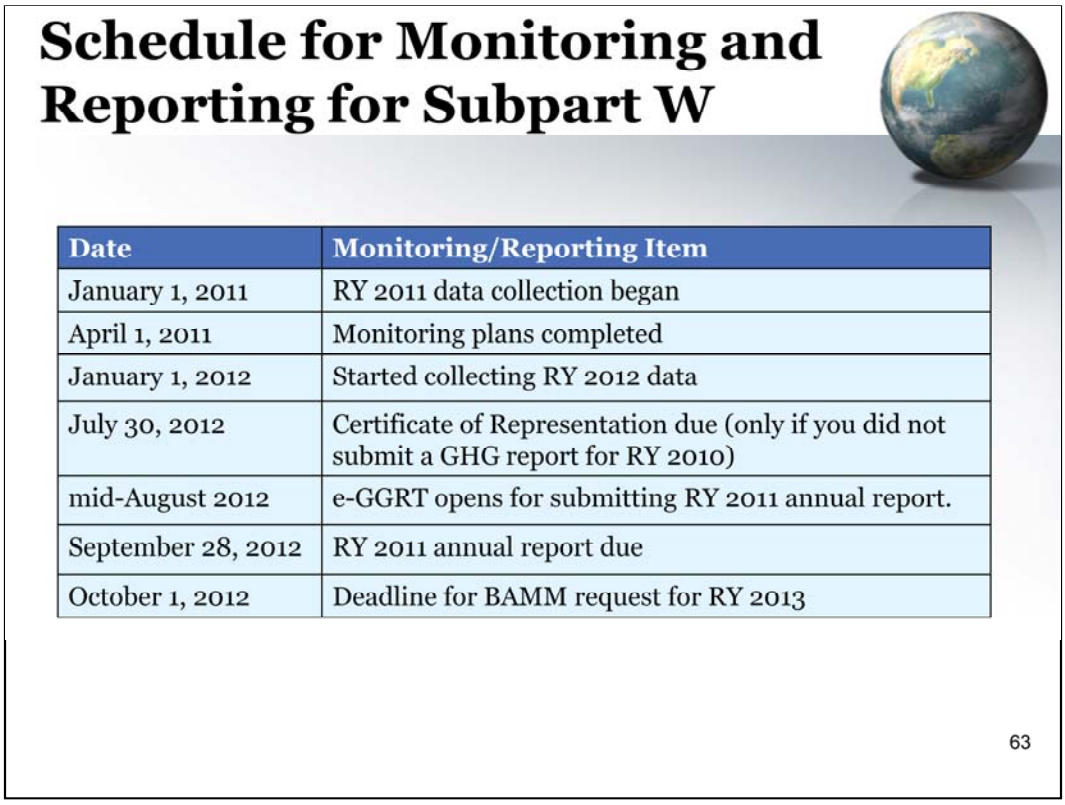
•Infrared laser beam illuminated instruments

•Acoustic leak detection devices

•Flow meters, composition analyzers, and pressure gauges

•Calibrated bags

•High volume samplers



The following dates are important for those facilities covered under subpart W:

1.January 1, 2011, data collection began.

2.April 1, 2011 monitoring plans were to be completed.

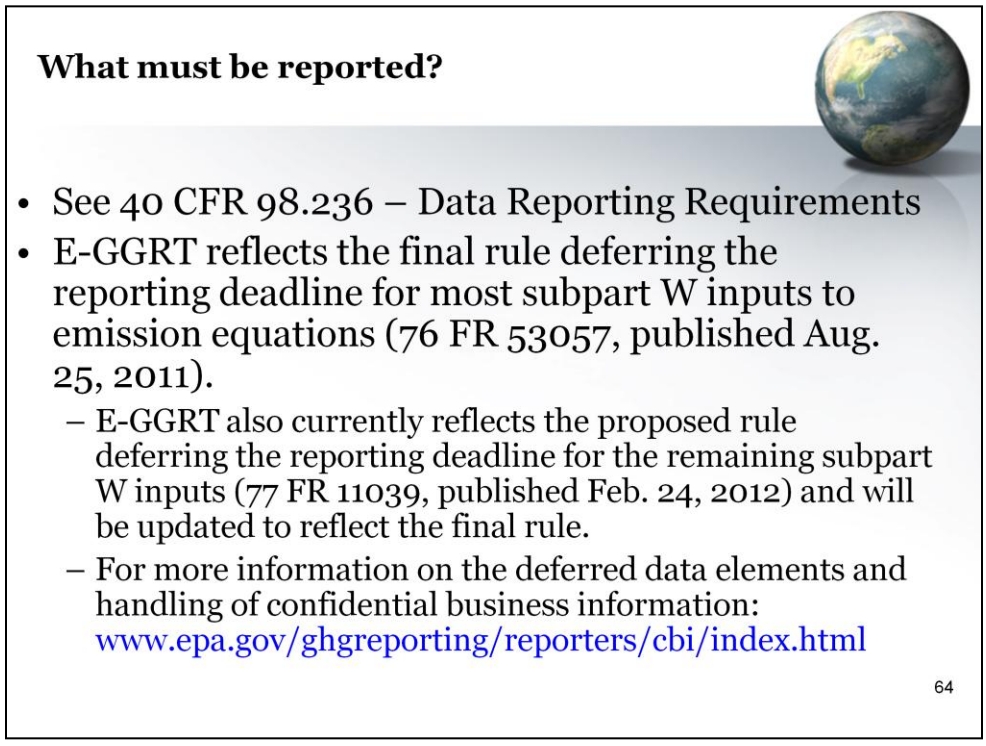
3. January 1, 2012, reporters started collecting 2012 data.

4.July 30, 2012 is when the certificate of representation is due to EPA. However. if you submitted a report for your 2010 emissions, you do not need to register again unless you want to modify your certificate of representation.

5. Mid-August 2012, e-GGRT opens for submitting RY2011 annual report.

6.September 28, 2012 is the deadline for which annual reports are to be submitted to EPA for RY2011 data.

7.October 1, 2012 is the deadline for requesting BAMM for RY 2013.

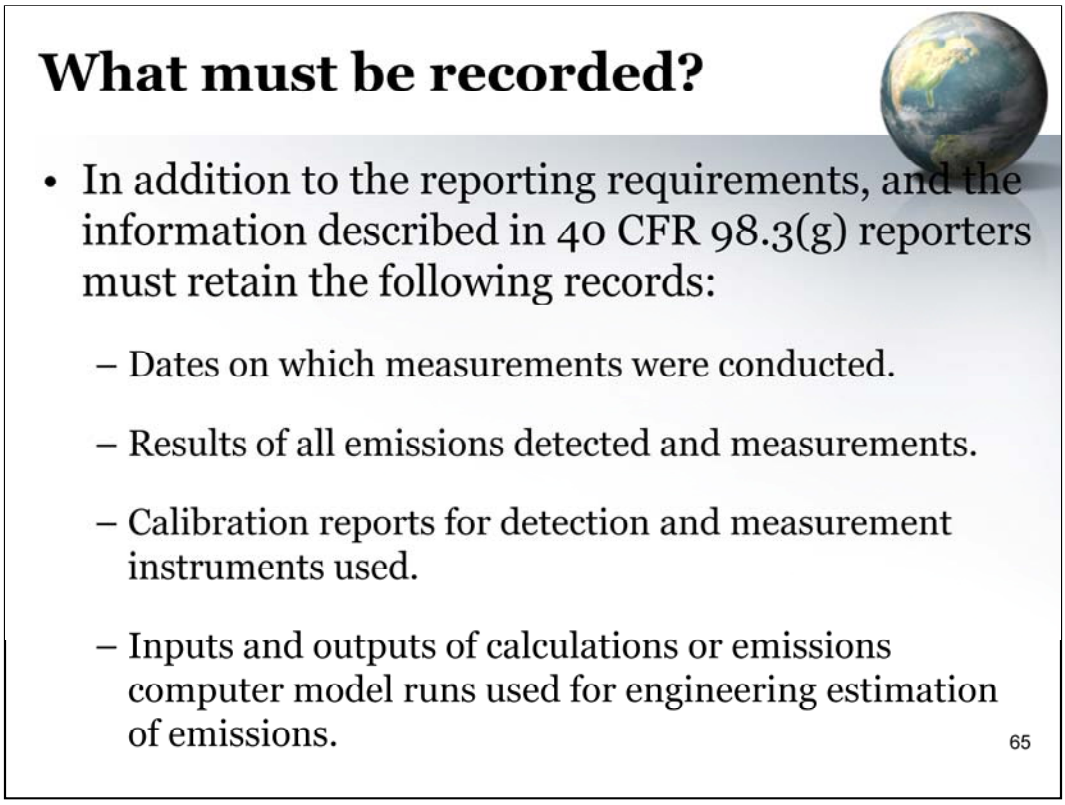


Section 98.236 of the rule provides a detailed listing of data reporting requirements for individual emissions sources and individual industry segments.

However, EPA is deferring the deadline for reporting inputs to emissions equations.

The inputs to emission equations for subpart W. are listed in the Table A-7, and are not required to be reported until 2015.

Facilities affected by this deferral will still need to report their reporting year 2011 emissions by September 28, 2012, but are not required to report the data elements listed in Table A-7 of subpart A.
For more information on the deferred data elements and handling of confidential business information, go to the CBI tab on the GHGRP web site.



In addition to the reporting requirements, reporters are required to retain additional information on their monitoring activity. For example, reporters must retain documentation on the dates on which measurements were conducted, results of emissions detected and associated measurements, calibration reports, along with inputs and outputs of engineering equations and estimations.

Missing Data Requirements

- If data are lost during annual emissions estimation or measurements, reporter must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting is obtained (data used to substitute for missing data cannot be used for that subsequent year's emissions estimation)
- For procedures used for obtaining missing data for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection
- For missing data which are continuously monitored or measured, reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

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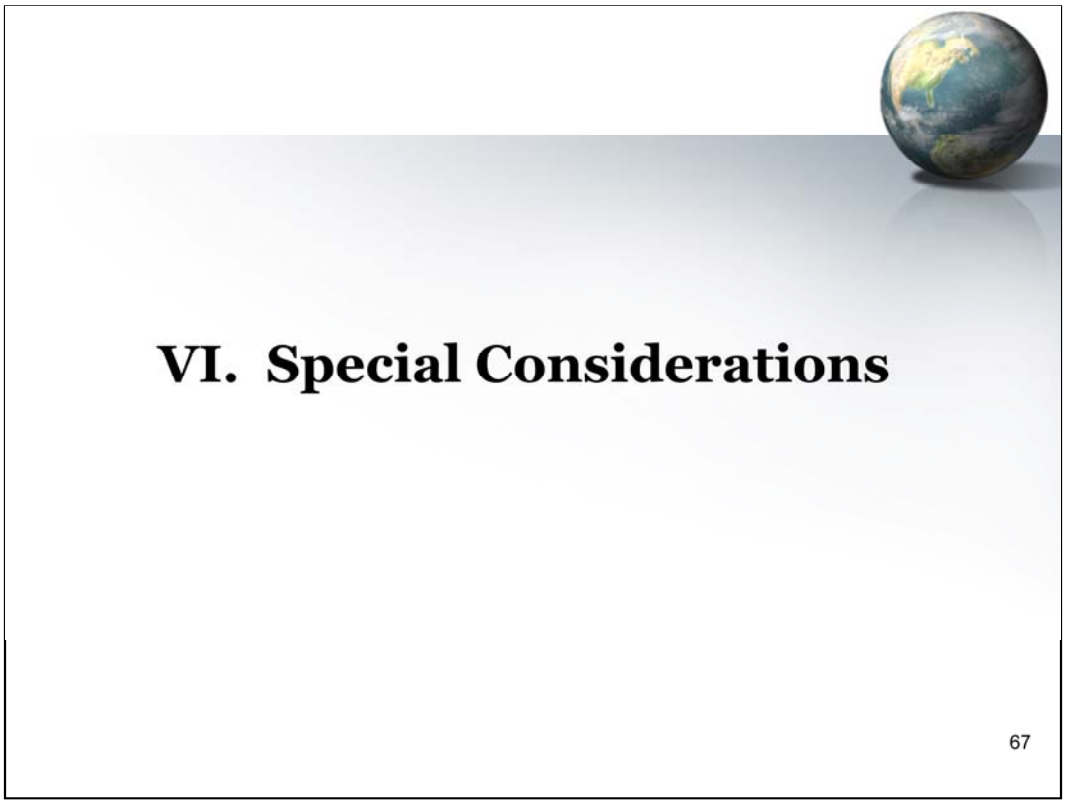
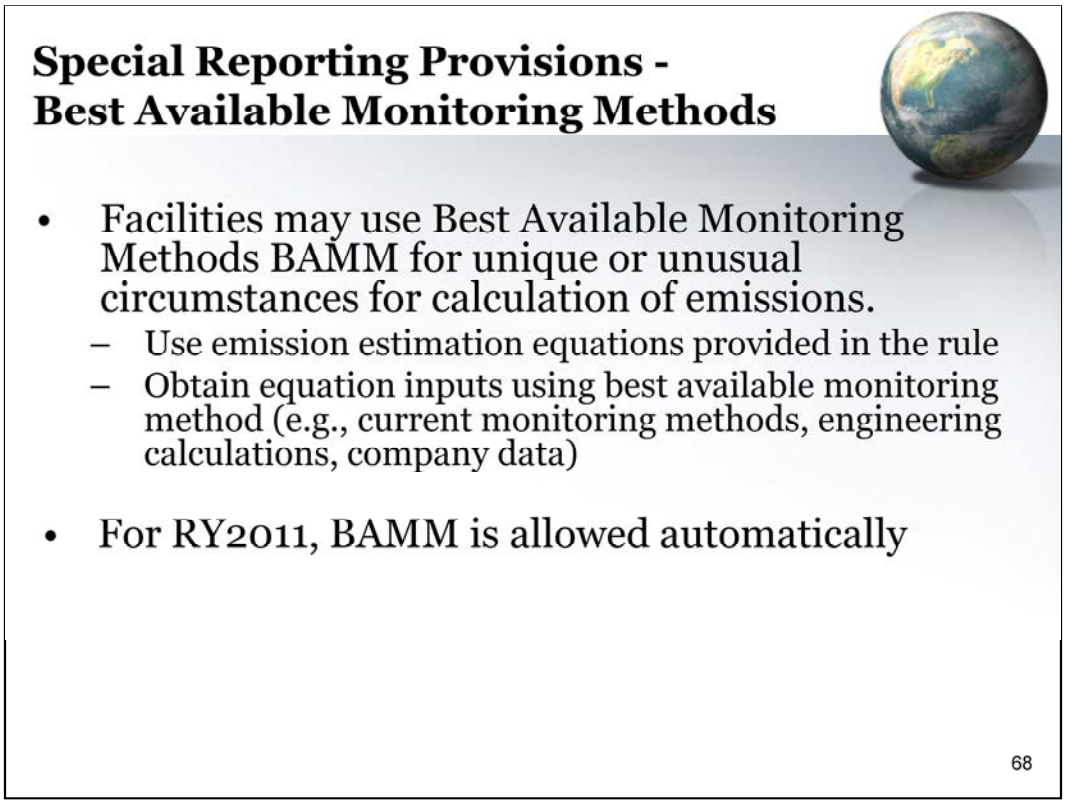


We will now take a look at the special considerations applicable to subpart W.

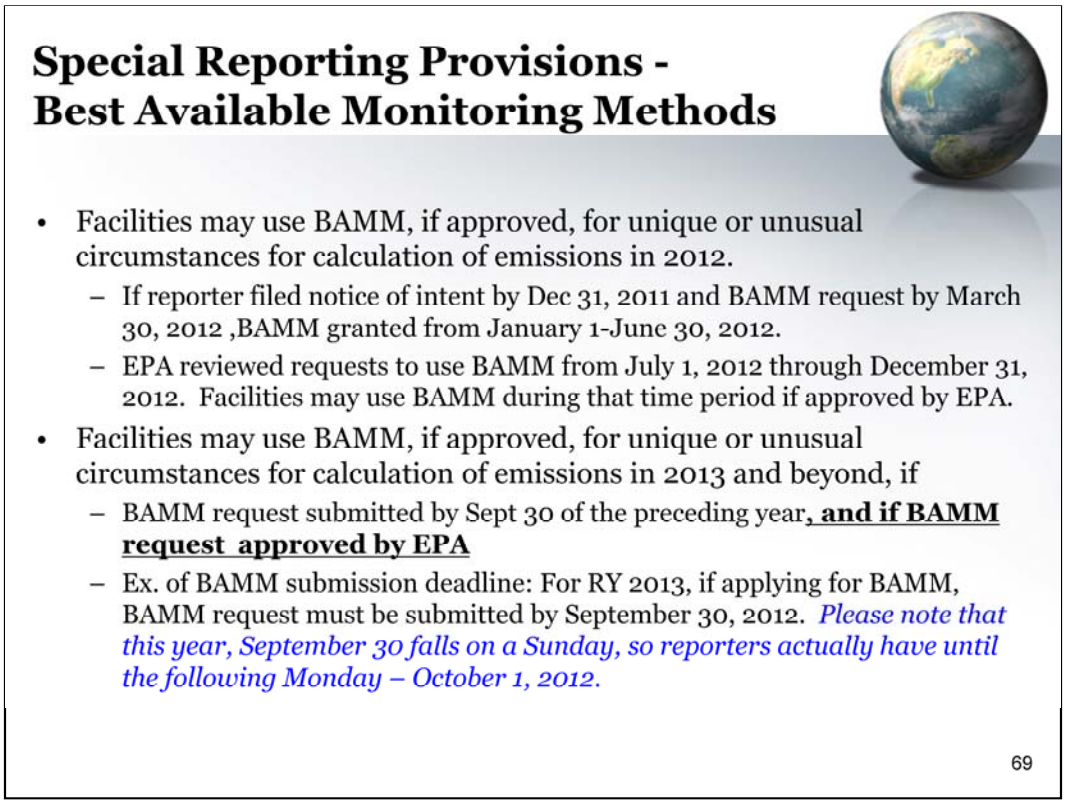


Facilities may use Best Available Monitoring Methods BAMM for unique or unusual circumstances based on provisions in the rule.

Reporters still must use emission estimation equations provided in the rule

Reporters then obtain equation inputs using best available monitoring method (e.g., current monitoring methods, engineering calculations, company data)

Please note, for RY2011, BAMM is allowed automatically



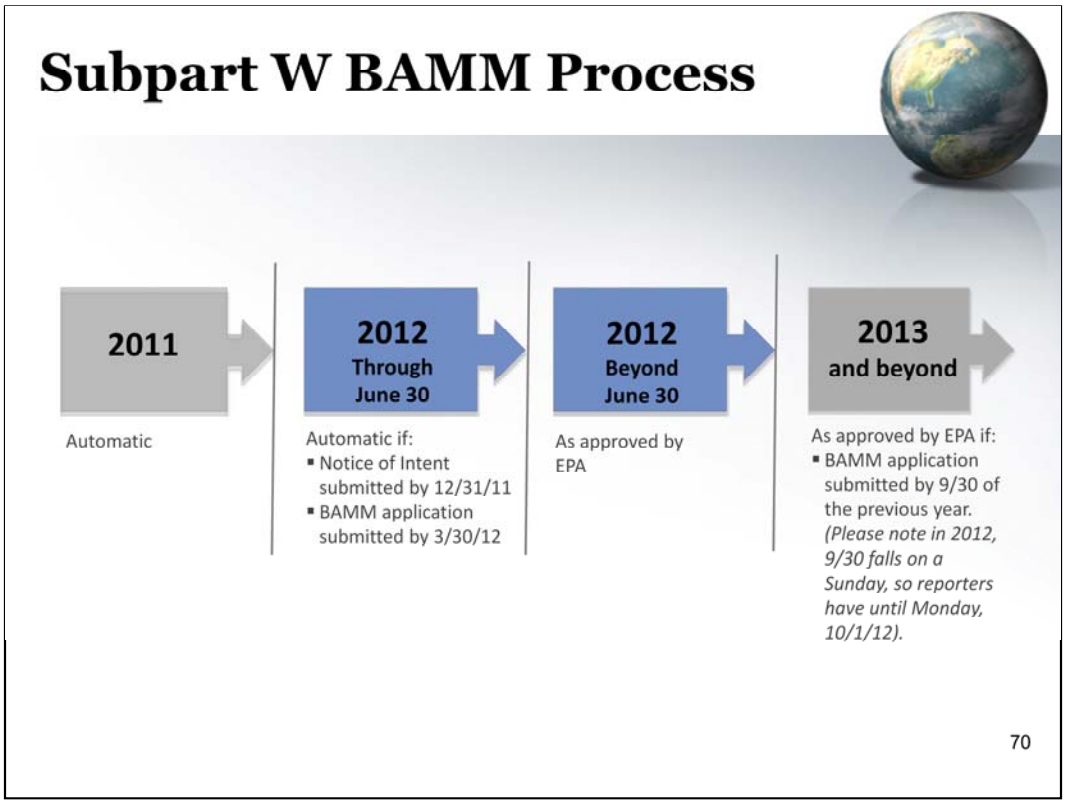
For RY2012, facilities may use BAMM, if approved, for unique or unusual circumstances for calculation of emissions in 2012.

If reporter filed notice of intent by Dec 31, 2011 and BAMM request by March 30, 2012 , BAMM automatically granted thru June 30, 2012.
EPA is reviewing requests to use BAMM beyond from July 1, 2012 through December 31, 2012. Facilities may use BAMM during that time period if approved by EPA.

For RY2013 and beyond, facilities may use BAMM, if approved, for unique or unusual circumstances for calculation of emissions in 2013 and beyond, if BAMM request submitted by Sept 30 of the preceding year, and if BAMM request approved by EPA.
Example of BAMM submission deadline: For RY 2013, if applying for BAMM, BAMM request must be submitted by September 30, 2012

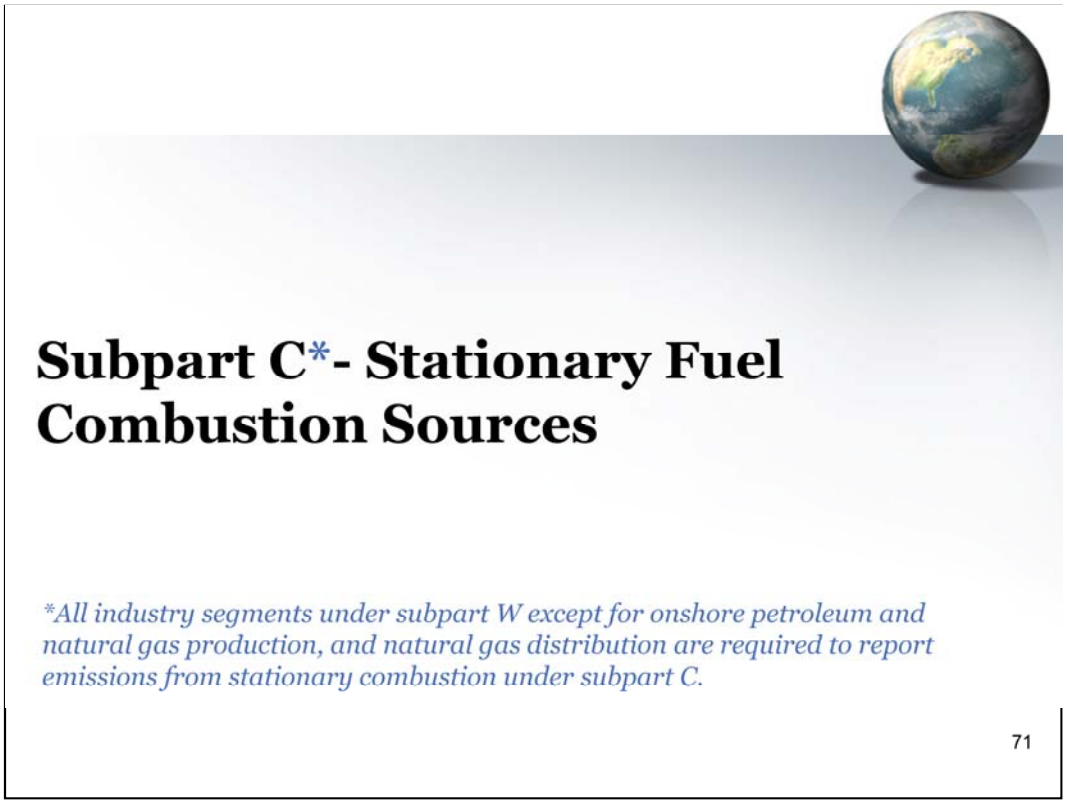
Even though slide has the September 30, 2012 date, that date this year falls on a Sunday so reporters actually have until the following Monday – October 1, 2012.

The use of BAMM will granted for durations no longer than the end of the data collection year. BAMM will be granted for a maximum of one year.



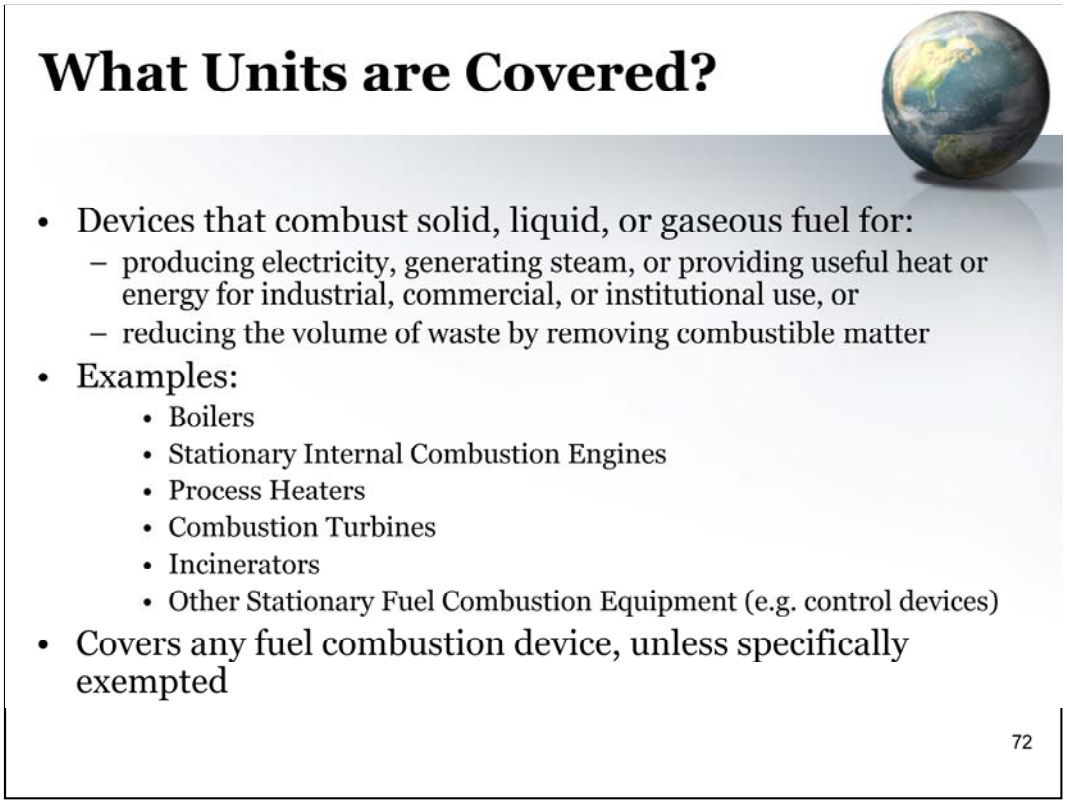
This slide shows a graphic of the BAMM timeline.

Even though slide shows the September 30 deadline for RY2013 and beyond, please note that this year, that date falls on a Sunday - so reporters actually have until the following Monday – October 1, 2012.



Next we will talk about the Stationary Fuel Combustion Sources category in the Greenhouse Gas Reporting Rule.

Please note that all industry segments under subpart W except for onshore petroleum and natural gas production, and natural gas distribution are required to report emissions from stationary combustion under subpart C.



The stationary combustion units covered under Subpart C include:

Devices that combust solid, liquid, or gaseous fuel on site for producing electricity, generating steam, or providing useful heat or energy or for reducing the volume of waste by removing combustible matter

Examples of such devices include

Boilers

Stationary Internal Combustion Engines

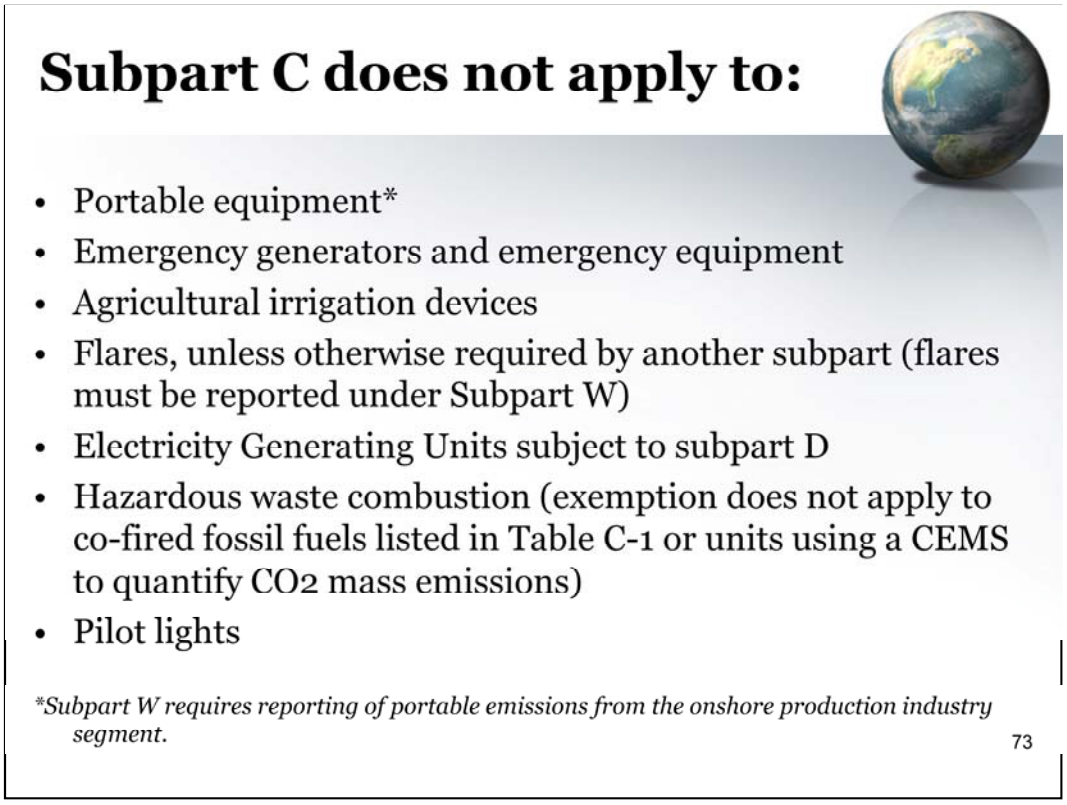
Process Heaters

Combustion Turbines

Incinerators

Other Stationary Fuel Combustion Equipment (e.g. control devices)

It covers any fuel combustion device, unless specifically exempted



Subpart C does not apply to:

Portable equipment

Emergency generators and emergency equipment

Agricultural irrigation devices

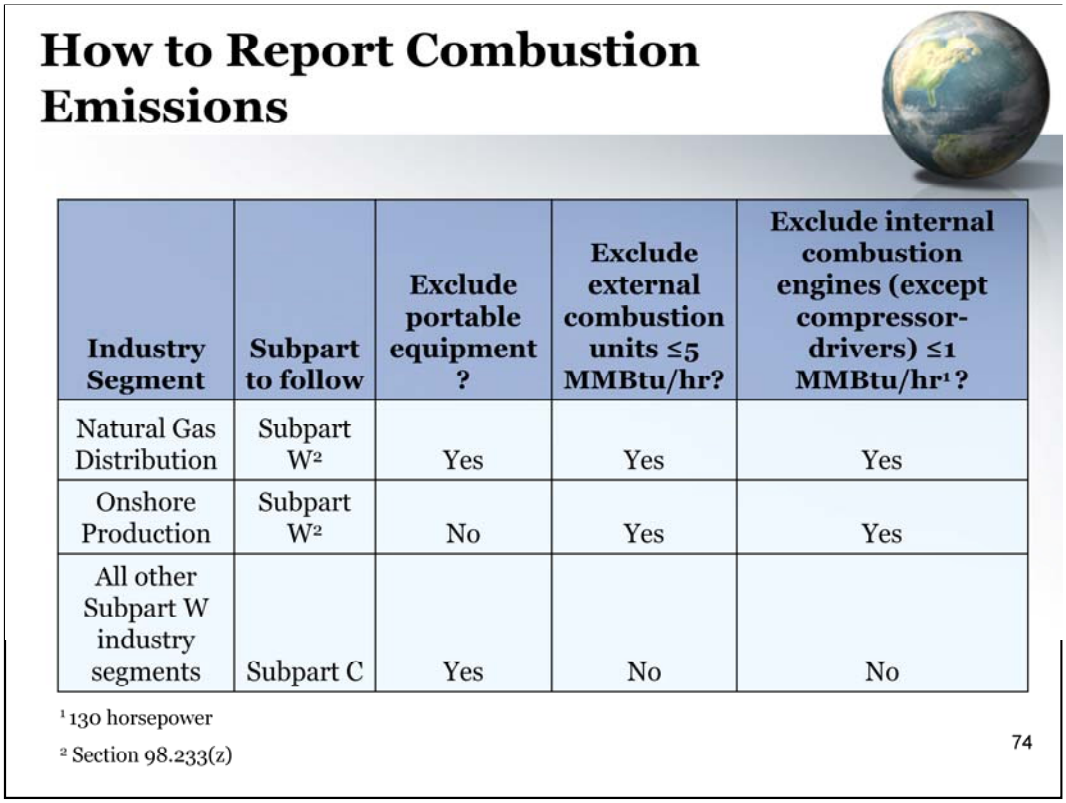
Flares, unless otherwise required by another subpart

(Flares must be reported under Subpart W)

Electricity Generating Units subject to subpart D

Hazardous waste combustion (exemption does not apply to co-fired fossil fuels listed in Table C-1 or units using a CEMS to quantify CO2 mass emissions)

Pilot lights



How to Report Combustion Emissions

Industry Segment	Subpart to follow	Exclude portable equipment ?	Exclude external combustion units ≤5 MMBtu/hr?	Exclude internal combustion engines (except compressor-drivers) ≤1 MMBtu/hr[1] ?
Natural Gas Distribution	Subpart W[2]	Yes	Yes	Yes
Onshore Production	Subpart W[2]	No	Yes	Yes
All other Subpart W industry segments	Subpart C	Yes	No	No

[1] 130 horsepower

[2] Section 98.233(z)

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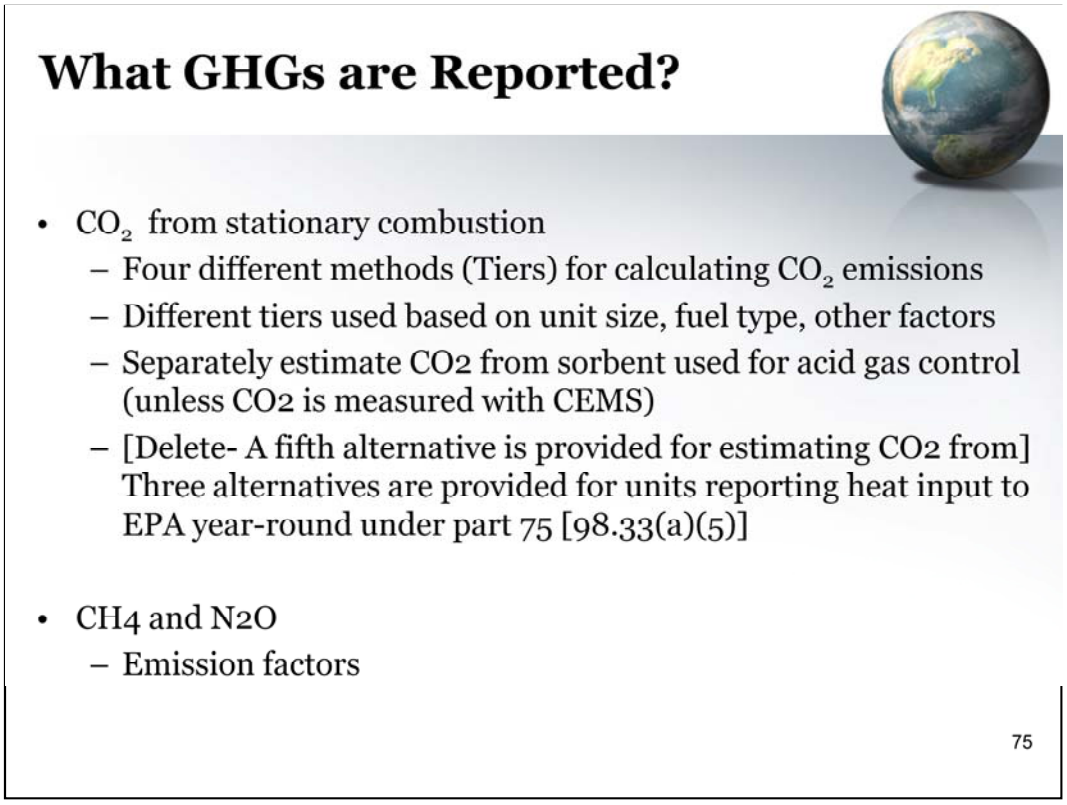
This slide outlines the requirements for combustion sources.

The second column – “Subpart to follow” – indicates the subpart under which combustion emissions will be reported

The third column – “Include portable equipment” – indicates whether or not one of the industry segments listed will report emissions from portable equipment. Where there is a “yes” in this column, that industry segment, in this case Onshore Production, will report emissions from portable equipment under subpart W and not under subpart C.

The fourth column – “Report emissions from external combustion units ≤ 5 MMBTU/hr” indicates whether or not a particular industry segment will report emissions on external combustion units that fall below the 5 MMBtu cutoff.

In the case of the natural gas distribution and onshore production industry segments, annual emissions are not reported for internal combustion units (except compressor-drivers) equal to or below 1 MMBtu/hr rated heat capacity limit. But the type and number of each unit must be reported.



The rule requires reporting of three greenhouse gases—carbon dioxide, methane, and nitrous oxide—from combustion of fossil fuel and biomass. The rule specifies four methods for calculating CO_2 emissions, referred to as calculation "tiers" by the rule. You may be able to choose among two or more of the tiers, depending on unit size, fuel type, and other factors.

If you have a fluidized bed unit or flue gas desulfurization unit, the rule also requires reporting of carbon dioxide from sorbent use, if you are not using a continuous emission monitoring system.

For methane and nitrous oxide, there are several equations provided in the rule. The method that you use depends on which CO_2 tier you use, and the equations generally use the same data that you collect for estimating CO_2 emissions.

CH4 and N2O are based on simple emission factors

CO_2 Emission Calculation Tiers

Tier	For this fuel...	Measure these parameters...	And use a default factor for...
1	60 fuels[1]	Annual fuel use	HHV CO_2 emission factor
2	60 fuels[1]	Annual fuel use HHV	CO_2 emission factor
	MSW	Steam generation	CO_2 emission factor
3	Solid/liquid	Annual fuel use Carbon content	--
	Gas	Annual fuel use Carbon content Molecular weight	
4	All	CO_2	--

[1]Any of the fuels listed in Table C-1 of subpart C, except MSW units that generate steam.

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Chart shows the parameters that you measure for the 4 Tier methods.

Tiers 1-3 provide equations that you plug different measured parameters into and tier 4 is CEMS.

Tier 1- Use for any of 60 fuels in Table C-1 of the rule. Measure only fuel use. Use an emission factor and default HHV by fuel

Tier 2- Measure fuel use and HHV

Tier 3- Measure fuel use and carbon content and for gaseous fuel also MWt.

Lower tiers measure less / higher tiers measure more but provide a more precise emission estimate.

Different tiers can used based on unit size, fuel type, and other factors. Generally, tiers 1 and 2 are for small sources <250 MBH, and Tiers 3 and 4 are for larger sources.

Tier 4 (CEMS) is required only if you already are required to use a CEMS and if certain other conditions are met.

CH4 and N2O Calculation Methods

If you use this Tier for CO2	Measure these parameters[1]	And use a default factor for
Tier 1 or Tier 3	Annual fuel use[2] (Eqs.C-8, C-8a, C-8b)	HHV (Eq. C-8 only) CH4 emission factor N2O emission factor
Tier 2 Fuel Option	Annual fuel use HHV (Eq. C-9a)	CH4 emission factor N2O emission factor
Tier 2 Steam Option	Annual steam generation MMBtu/lb steam output (Eq.C-9b)	CH4 emission factor N2O emission factor
Tier 4	Annual heat input (Eq.C-10)	CH4 emission factor N2O emission factor

[1]Use same values as used for CO_2 calculations

[2] Measured for Eq. C-8; obtained from billing records for Eqs. C-8a, C-8b

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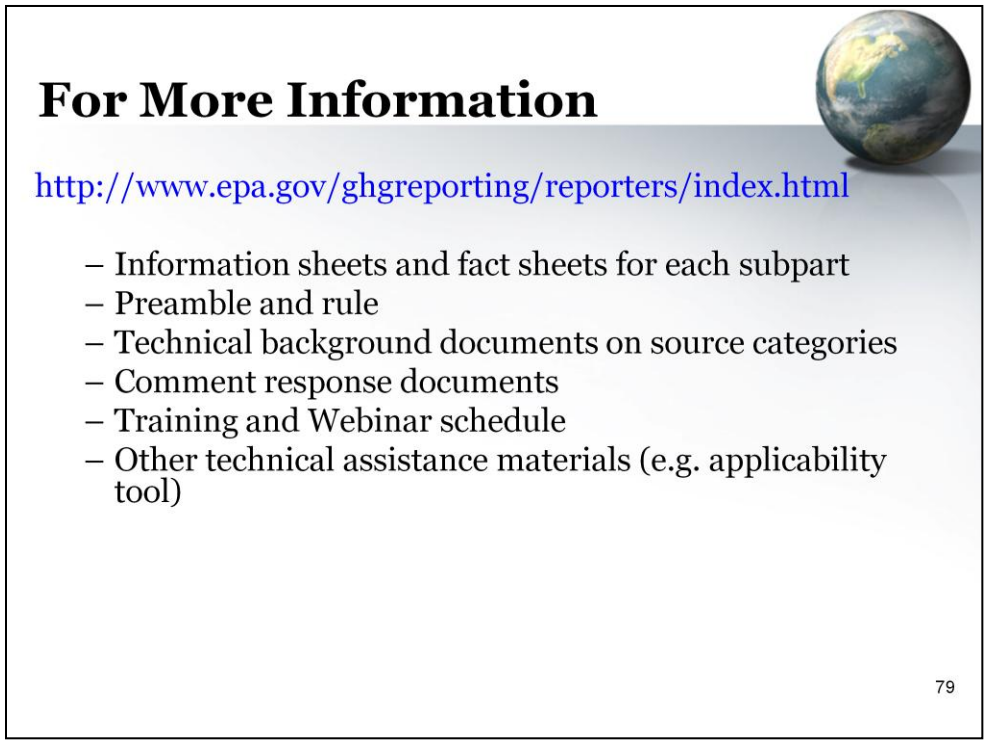
For these combustion units required to report, in addition to CO2 emissions, emissions of CH4 and N2O also need to be estimated.

This slide shows the methods for making these estimates, for each of the 4 reporting tiers.

The method that you use depends on the Tier method used for CO2…. the concept being that whatever you measure for estimating CO2, you use the same parameters to estimate CH4 and N2O.

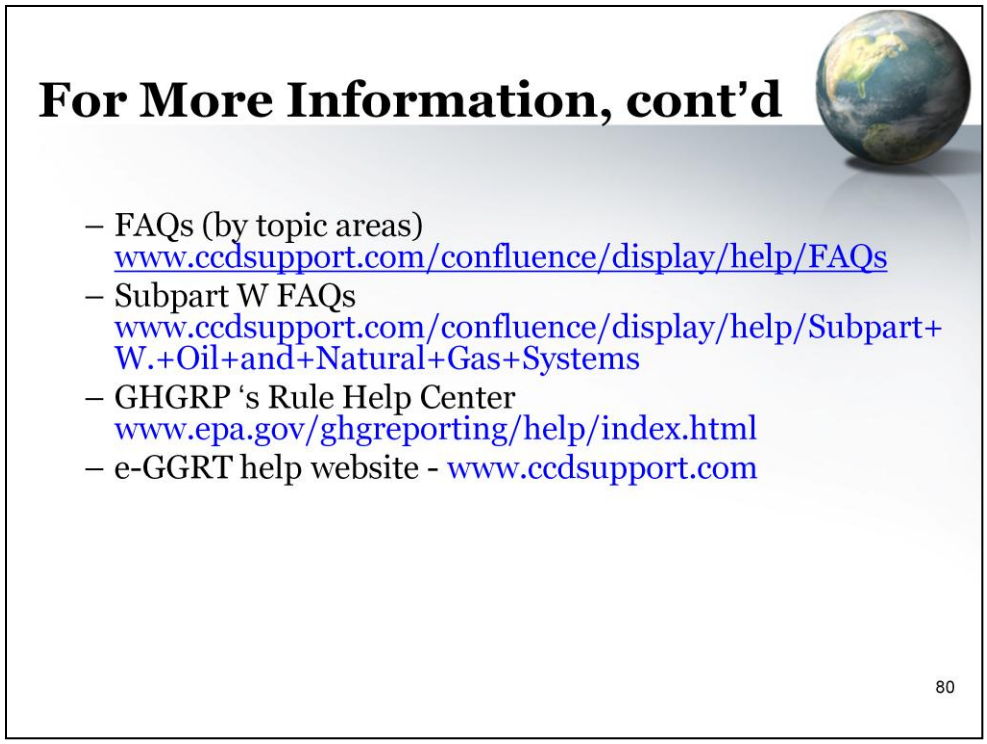
Finally, we will talk about where reporters can get more information



A very important website to keep checking is the GHGRP's main website. You can find this web site by navigating to the address shown on the slide.

From this website you can navigate to a tab for each subpart and find information such as fact sheets, subpart information sheets, the preamble and rules, technical background documents, and comment response documents.

You can also find the training and webinar schedule and other technical assistance documents such as the applicability tool and Frequently asked questions, by topic area.



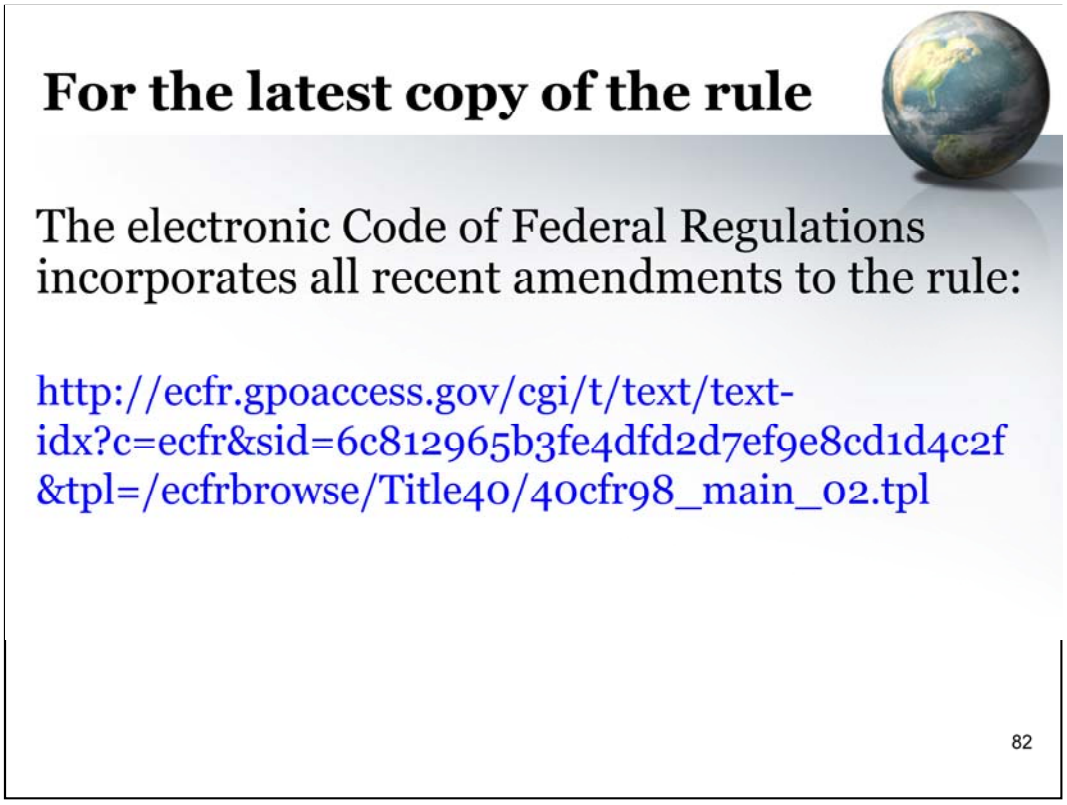
1. You can also find responses to Frequently Asked Questions or FAQs. Here the FAQ link.
2. Under that is the link for just the subpart W FAQs.
3. We also have a GHG Reporting Program Help Center. This website has a number of tools and documents to assist in understanding and complying with the Greenhouse Gas Reporting Program, and also includes links to the applicability tool, FAQs, and the Help Desk. The third bullet show the link for that.
4. There is also a an e-GGRT data reporting system website. This web page includes reporting instructions, tutorials and other helpful content on e-GGRT as well as the GHG Reporting Program. The link is shown for that website.

Finally, if you still have questions, you can contact the GHG reporting program help desk to get answers to any questions that may arise as you complete the user and facility registration process.

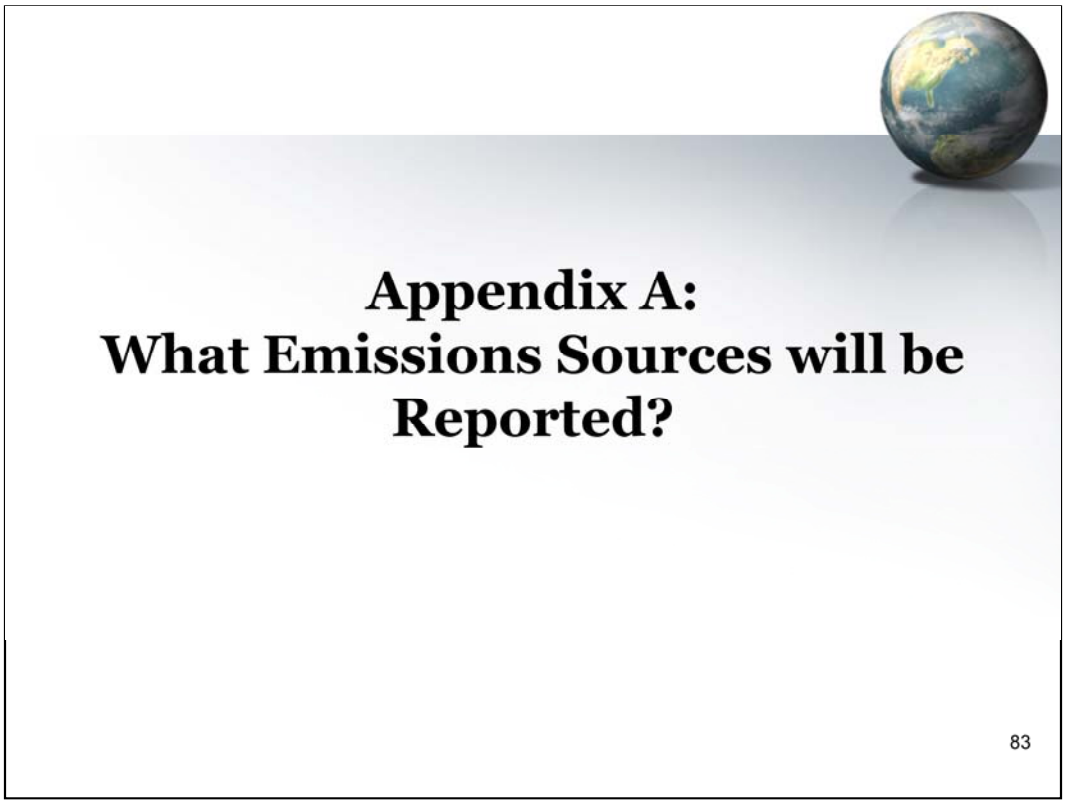
This help desk will operate during regular business hours.

e-GGRT related questions – answered quickly

Subpart W-related questions – may take more time – Please note that we can't answer questions that are currently the subject of ongoing litigation. Also please note that for reporting year 2011, BAMM provisions are available to calculate emissions; please refer to 40 CFR 98.234 (f) for further details. However, if your question is not on an issue of ongoing litigation, please submit it to the Help Desk. It may seem like it takes a lot of time, but the Help Desk questions and responses are vetted for technical and legal accuracy. And know that once your question has been submitted, it is being worked on.



The EPA web site contains a copy of all proposed and final rule revisions for subpart W, but to find a copy of the currently applicable rule that incorporates all rule amendments, visit the electronic code of federal regulations at the address shown on the slide.



Appendix A includes a listing of the Emission Sources that will be reported under subpart W.

What emission sources will be reported?

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Underground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
Natural gas pneumatic device venting		X		X	X			
Natural gas driven pneumatic pump venting		X						
Acid gas removal vent stack		X	X					
Dehydrator vent stacks		X	X					
Well venting for liquids unloading		X						
Gas well venting during well completions and workovers with hydraulic fracturing		X						

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What emissions sources will be reported? (cont'd)

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Underground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
Gas well venting during well completions and workovers without hydraulic fracturing		X						
Blowdown vent stacks			X	X			X	
Onshore production storage tanks		X						
Transmission storage tanks				X				
Well testing venting and flaring		X						
Associated gas venting and flaring		X						
Flare stacks		X	X					

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What emissions sources will be reported? (cont'd)

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Underground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
Centrifugal compressor venting		X	X	X	X	X	X	
Reciprocating compressor rod packing venting		X	X	X	X	X	X	
Other emissions from equipment leaks		X	X	X	X	X	X	X
Population Count and Emissions Factor		X			X	X	X	X
Vented, Equipment Leaks and Flare Emissions Identified in BOEM GOADS Study	X							

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What emissions sources will be reported? (cont'd)

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Underground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
Enhanced Oil Recovery hydrocarbon liquids dissolved CO_2		X						
Enhanced Oil Recovery injection pump blowdown		X						
Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions		X						X

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