MEMORANDUM

FROM: Akachi Imegwu, U.S. EPA, Climate Change Division

TO: Docket EPA-HQ-OAR-2011-0512, Mandatory Reporting of Greenhouse Gases: Technical Revisions to the Electronics Manufacturing and the Petroleum and Natural Gas Systems Categories of the Greenhouse Gas Reporting Rule

DATE: August 17, 2011

SUBJECT: Summary of questions raised on subpart W of the final Mandatory Reporting of Greenhouse Gases Rule (40 CFR Part 98) after promulgation that are addressed in the proposed action: 2011 Technical Revisions to the Electronics Manufacturing and the Petroleum and Natural Gas Systems Categories of the Greenhouse Gas Reporting Rule

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1.0 INTRODUCTION

The 2010 final rule for Subpart W of the Greenhouse Gas Reporting Rule (Subpart W) was signed by EPA Administrator Lisa Jackson on November 8, 2010 and published in the Federal Register on November 30, 2010 (75 FR 74458). The 2010 final rule, which became effective on December 31, 2010, included reporting of GHGs from facilities containing petroleum and natural gas systems. The rule does not require control of GHGs, rather it only requires that facilities containing petroleum and natural gas systems with emissions sources above certain threshold levels monitor and report emissions and other related data.

Since promulgation of the final rule in November 2010, EPA has received several questions from reporters and trade associations. In addition, the Administrator has identified within subpart W a number of technical issues that need to be revised and specific provisions that need to be clarified. EPA is proposing to amend specific provisions in Subpart W to make technical and editorial revisions that have been identified since promulgation and to propose clarifying or other amendments to certain provisions that have been the subject of questions from reporting entities.

The purpose of this memorandum is to describe the extent of EPA's outreach efforts for Part 98, subpart W, and to summarize the questions that have been raised during EPA's outreach activities that are being addressed by some of the proposed amendments.

2.0 SUMMARY OF EPA OUTREACH ACTIVITIES ON THE GREENHOUSE GAS PROGRAM

EPA has conducted an extensive outreach program for the Greenhouse Gas Program, including meetings with trade associations and individual businesses, on-line web-based seminars (webinars), and training sessions for EPA Regional Offices. A subset of those meetings were specifically targeted for subpart W reporters. The following table lists those meetings and webinars that EPA has conducted to date, along with the month and year of the activity. When available, the table also includes the approximate attendance for the meeting or webinar. In addition, the meetings and webinars that were specifically targeted to subpart W reporters are in yellow highlighted text.

POST-SIGNATURE MEETINGS AND WEBINARS

Month and Year of Information Meeting or Webinar Organization or Location (estimated attendance, if available)
Sept 2009
EPA Regional Offices Briefing (100)
Agriculture community teleconference (100)
State and Local Agencies teleconference (100)
Clean Energy Group Meeting (about 40)
State of Washington (2)
Business Council (73)
Call with Massachusetts on data system (2)
Overview webinar (293)
US Climate Action Partnership (20)
Overview webinar (284)
National Cooperative Refinery Association, and Van Arsdall & Associates
Oct 2009
Oil and Gas Compact (30)
Portland Cement Assoc. (20)
CENSARA(50)
Overview webinar (217)
Applicability Tool Demonstration (84)
National Lime Assoc. (3)
Detailed webinar (252)
EEI (80)
NACAA (75)
Nitric Acid and Ammonia Assoc.(30)
TFI, AISI, SMA
Overview webinar (176)
Detailed webinar (208)
Air Program Managers and staff (25)
Detailed webinar (206)
Aluminum Industry
Steel Manufacturers Assoc.
Natural Gas Star
Overview webinar (133)
Carolina Air Pollution Control Assoc. (400)
Applicability Tool Demonstration (238)
Waste Management and Equipment Companies (25)
Ohio Manure Storage
Overview webinar (251)
Corporate Climate Regulation, Chicago, IL
Midwest Transportation & Air Quality Conference
Detailed webinar (333)
TCR/CAA (90)
Environmental Groups (10)
API

POST-SIGNATURE MEETINGS AND WEBINARS

Month and Year of Information Meeting or Webinar **Organization or Location (estimated attendance, if available)**
NOV 2009
Misc. Meetings with Industries (Refineries, Pulp and Paper, Cement) (100)
Northeast Gas Assoc.
Ecology and Environment, Inc. (2)
Detailed webinar (253)
TCR
Tribal Air Coordinators (50)
GHG data exchange discussion with New Mexico (8)
API (20)
ABA (100)
Training for three regional cap and trade programs – DC (70)
State-EPA Dialogue - DC (80)
Treated Wood Council (60)
Detailed webinar (172)
MAPI (Manufacturing Alliance) (15)
Environmental Services Corporation (150)
Western Climate Initiative partner meeting – Santa Fe (50)
Detailed webinar (171)
Regional Climate sub-leads (40)
Air Products (5)
Waste Management and others (10)
Detailed webinar (96)
DEC 2009
AWMA-EPA- RTP (100)
Envirosys (4)
Detailed webinar (50)
ACC (5)
National Grid
Detailed webinar (91)
Utilitpoint and Allegro (115)
CARB
NPRA and API
Golder and Associates
Anadarko (10)
Kinder Morgan
EEI
SWANA- LFGTE
Thermo Fisher Scientific
EPA Region 4 Training (100)
Waste Management and others (8)
Air Products (5)
The Fertilizer Institute
ADM (8)

POST-SIGNATURE MEETINGS AND WEBINARS

Month and Year of Information Meeting or Webinar Organization or Location (estimated attendance, if available)
JAN 2010
Detailed webinar (83)
Air Products
National Emissions Inventory (30)
OECA- Regional offices (30)
National Grid
Alliance of Automobile Manufacturers (9)
Detailed webinar (100)
NRPA (300)
Feb 2010
Dedicated webinar for American Colleges and Universities (220)
EPA Regional Inventory, Enforcement (23)
University Challenge
State webinar (200)
Webinar (182)
Iowa Landfill operators (125), Asphalt Paving Association of Iowa (70), and the Iowa Chapter of AMWA (60).
Mar 2010
Inst. Of Clean Air Companies (23)
SWANA (200)
EPA AFS Compliance Meeting
Second Nature (Colleges/Universities) Panel (20)
ECOS (50)
PCA
Training- EPA Regions 5 and 7 (180)
Iowa Landfills (50)
April 2010
Arkansas Environmental Federation, Little Rock (160)
NACAA Emissions and Modeling Committee (30)
Webinar (75)
Central TX AWMA (50)
Chicago Exchange Meeting
Exchange Network National Meeting (50)
EPA Air Division Directors (20)
National Assoc. of Clean Water Agencies
Pepsico-Frito Lay (150)
Pacific NW Legislative Energy Horizon Inst./AGA (35)
May 2010
LA, Boise, Portland Training (150, 100, 70, respectively)
ESC Users Group (150)
NCASI
EPRI CEMUG (150)
June 2010
Webinar: Q&A Session (54)
October 2010
e-GGRT Training (748)

POST-SIGNATURE MEETINGS AND WEBINARS

Month and Year of Information Meeting or Webinar Organization or Location (estimated attendance, if available)
e-GGRT Training (566)
November 2010
e-GGRT Training (521)
Webinar: Subpart FF (44)
General Stakeholder Call: Subparts RR and UU (88)
December 2010
EPA Regional Offices Briefing
NACAA
Webinar: Subpart I (71)
Webinar: Subpart W (481)
Webinar: Subparts RR and UU (77)
Webinar: e-GGRT and OTAQREG Training (386)
Webinar: Subpart W (130)
January 2011
Webinar: Subpart W (138)
Webinar: e-GGRT Training (512)
February 2011
Webinar: Overview (98)
EEI: Subpart RR
May 2011
Webinar: Overview
Webinar: Subpart OO
June 2011
Webinar: Overview

3.0 SUMMARY OF QUESTIONS FROM THE EPA HELPLINE AND TRADE ASSOCIATIONS BEING ADDRESSED BY PROPOSED AMENDMENTS

EPA has maintained a web-based helpline that allows individuals to submit questions about subpart W. So far, EPA has resolved over 300 inquiries submitted on subpart W, since publication of the final rule in 2010. Most of those inquiries have been resolved by providing further guidance to reporting entities through a web-based list of answers to frequently asked questions. However, several additional questions would be resolved through the proposed amendments to subpart W.

The EPA has also held meetings with several trade associations representing industries affected by Part 98, and many questions were presented by those trade associations that would be resolved through the proposed amendments to subpart W.

For a summary of the questions that have been submitted through the EPA helpline along with questions and issues raised by trade associations on subpart W which are being addressed by the proposed technical revisions, please see Appendix A, "Summary of Questions and Issues from the EPA Helpline and Trade Associations Being Resolved By the Proposed Technical Corrections and Other Amendments." Not all of the technical revisions and other amendments correspond directly to questions that were raised by reporters. The need for some corrections and other amendments were identified as a result of internal EPA review stemming from reporter questions and may not be reflected in Appendix A. Any specific identifying information from the incoming questions has not been included in Appendix A.

4.0 SUMMARY OF ISSUES FROM INTERNAL REVIEW BEING ADDRESSED BY PROPOSED AMENDMENTS

As mentioned above, not all of the corrections and other amendments correspond directly to questions that were raised by reporters. The need for some corrections and other amendments were identified as a result of internal EPA review. For a summary of the issues that have been raised from the EPA's review of Subpart W of Part 98 which are being addressed by the proposed 2011 revisions package, please see Appendix B, "Summary of Issues From Internal Review Being Addressed by Proposed Amendments".

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Summary Of Questions And Issues From The EPA Helpline And Trade Associations Being Resolved By The Proposed Technical Corrections And Other Amendments

Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
Subpart W – Petroleum and Natural Gas			
1. Clarifying the equipment associated with onshore petroleum and natural gas production.	Is everything upstream of the gathering line covered by Onshore Production segment?	At least 4 individuals	Helpline
	Does Onshore Production portable equipment include only well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters located on a well pad?		Helpline
	Are Tank Vapor Recovery (TVR) and Casing Vapor Recovery (CVR) gas compressors included in Onshore Production segment?		Helpline
	Are dehydrators located at wellpads (on shore natural gas production facilities) considered processing equipment under onshore natural gas processing as defined in 98.230- Subpart W Petroleum and Natural Gas Facilities?		Helpline
2. Clarify that the onshore natural gas processing industry segment includes the separation of natural gas liquids into its components and that separation is forced extraction.	Under Subpart W of Part 98, the definition of Natural Gas Processing provides an unclear explanation of fractionation, additionally, fractionation is not defined within the rule. The definition is as follows: Natural gas processing separates and recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO2separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing facility, whether inside or outside the processing facility fence. This source category does not include reporting of emissions from gathering lines and boosting stations. This	At least 2 individual	Helpline

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	source category includes: (i) All processing facilities that fractionate. (ii) All processing facilities that do not fractionate with throughput of 25 MMscf per day or greater. The confusion lies as to what is actually meant by fractionation. Under the NSPS Subpart KKK, fractionation is the separating of natural gas liquids into natural gas products. However, under the description of processing as provided above, it includes "separation of natural gas liquids" and "fractionate" as part of what processing plants do. The main concern is if a plant that do not fractionate NGLs (as defined in Subpart KKK of the NSPS) is processes less than 25 MMscf/day but still separates out NGLs from the gas stream if they still meet the definition of "processing" or if they are then brought into "production" under the definition of a facility. Some clarification on this matter would be greatly appreciated.		
	1. 25 mmscf/day is design capacity for a processing plant or the actual in the following definition in 98.230(a)(3): Onshore natural gas processing. Natural gas processing separates and recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing facility, whether inside or outside		Helpline

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	the processing facility fence. This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes: (i) All processing facilities that fractionate. (ii) All processing facilities that do not fractionate with throughput of 25 MMscf per day or greater. 2. Per this definition, we understand that if a booster processes 25 or more mmscf/day gas and generates condensate or produced water, it is considered Natural gas processing per this quoted definition. Please verify. Please note even this booster site does not generate J. T. Liquid or/and NGL.		
	Some facilities are designed solely to fractionate natural gas liquid streams. These facilities receive an inlet stream of natural gas liquids (not a gaseous form of natural gas) which does not contain methane. The facilities are designed to fractionate the liquids into individual products (ethane, propane, etc.) and do not produce a methane stream. The definition of Onshore Natural Gas Processing [98.230(a)(3)] states that this segment "separates and recovers NGLs and/or other non-methane gases and liquids from a stream of produced natural gas ". The definition of natural gas [according to 98.6] refers to "gases" – i.e., streams in a gaseous form ("hydrocarbon and non-hydrocarbon gases [...] field production gas, process gas, and fuel gas"). Natural gas liquids are defined separately, and are not mentioned as the stream being processed in the definition of Onshore Natural Gas Processing. Therefore, please confirm that facilities designed to fractionate natural gas liquid streams are not included in the definition of Onshore Natural Gas Processing and are therefore not required to report under Subpart W.		Helpline

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	My environmental consulting firm works with a natural gas midstream company. This company does not own offshore or onshore production, underground natural gas storage, LNG storage, LNG import and export equipment, or natural gas distribution. They do own facilities that are potentially part of the onshore natural gas processing and onshore natural gas transmission compression industry segments. The specific definitions of these industry segments are as follows: "Onshore natural gas processing. Natural gas processing separates and recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing facility, whether inside or outside the processing facility fence. This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes: i. All processing facilities that fractionate. ii. All processing facilities that do not fractionate with throughput of 25 MMscf per day or greater." [98.230(a)(3)] "Onshore natural gas transmission compression. Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon		Helpline

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	liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include reporting of emissions from gathering lines and boosting stations – these sources are currently not covered by subpart W." [98.230(a)(4)] They own three natural gas processing facilities that do not fractionate. All three of these facilities have actual and potential natural gas throughputs below 25 MMscf per day; therefore, they are not included in the definition of the onshore natural gas processing industry segment. The determinations of if they are included in the onshore natural gas transmission compression industry segment are as follows. • Gas Plant A does not have compression. This facility does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Gas Plant B does have compression. The facility receives gas from production and delivers gas to an interstate transmission pipeline. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Gas Plant C does have compression. The compression receives gas from production and discharges it to the inlet of the processing, and there is no residue (sales) gas compression at this facility. The plant outlet delivers gas to a distribution company. Because the compression moves gas to the inlet of the processing plant and not to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W.		

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	This company also owns multiple natural gas compression facilities. All of these facilities do not fractionate and have actual natural gas throughputs below 25 MMscf per day; therefore, they are not included in the definition of the onshore natural gas processing industry segment. The determinations of if they are included in the onshore natural gas transmission compression industry segment are as follows. • Compressor Station 1: This station is on a pipeline system that receives gas from an interstate pipeline and delivers gas to a distribution company and end users upstream of a distribution company. Because the compression does not move gas from production or processing, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 2: This station is on a pipeline system that receives gas from production and delivers gas to an interstate pipeline, a distribution company, and end users upstream of a distribution company. Therefore, it does meet the definition of the onshore natural gas transmission compression industry segment. • Compressor Station 3: This station is on a pipeline system that receives gas from production and delivers gas to an interstate pipeline. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 4: This station is on a pipeline system that receives gas from production and delivers gas to a processing facility. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 5: This station is on a pipeline system that receives gas from production and delivers gas to a distribution company. Therefore, it does meet the definition of the onshore natural gas transmission		

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	compression industry segment. • Compressor Station 6: This station is on a pipeline system that receives gas from production or another gathering pipeline and delivers gas to a processing facility. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 7: This station is on a pipeline system that receives gas from production and delivers gas to a processing facility. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 8: This station is on a pipeline system that receives gas from production and delivers gas to an interstate pipeline. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 9: This station is on a pipeline system that receives gas from production and delivers gas to a processing facility. Because the compression does not move gas to a distribution pipeline or into storage, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. • Compressor Station 10: This station is on a pipeline system that receives gas from an interstate pipeline and delivers gas to a distribution company and end users upstream of a distribution company. Because the compression does not move gas from production or processing, it does not meet the definition of the onshore natural gas transmission compression industry segment and is not subject to Subpart W. The three facilities that are on pipeline systems that deliver gas to end		

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	users, Compressor Stations 1, 2, and 10, are not included in the definition of the natural gas distribution industry segment. The definition of this industry segment includes the statement, "This segment excludes customer meters and infrastructure and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and "farm taps" upstream of the local distribution company inlet." [98.230(a)(8)] The deliveries to end users on these systems are upstream of the local distribution company. Compressor Stations 2 and 5 are required to report under Subpart W of the GHG reporting rule if their combined actual emissions from stationary fuel combustion units and Subpart W emissions sources exceed the 25,000 MT CO2e threshold. Are these applicability determinations based on appropriate interpretations of the rule, and are the applicability determinations accurate?		
	Facility Definition: Subpart W defines onshore natural gas processing as "facilities that separate and recover natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO2 separated from natural gas streams.....This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes: (1) all processing facilities that fractionate and (2) those that do not fractionate with throughput of 25 MMscf per day or greater." Would a compressor station that moves natural gas to transmission or distribution pipelines that has a dehydration unit for water removal (but does not recover NGLs) be considered a processing facility based on this definition?		Helpline

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	If the answer to the question above is "NO", then presumably this facility would fall under the definition of transmission compression. As such, would GHG emissions from the dehydrator vent be required to be included in the reporting for the station since this source type is not indicated under the natural gas transmission compression sector category?		
3. Clarify that onshore natural gas processing includes residue gas compression equipment that is owned or operated by the plant.	Do compressors at the processing facility that push the natural gas at elevated pressure into the transmission lines fall under "processing" or "transmission"?	At least 2 individual	Helpline
	Facility Definition: Subpart W defines onshore natural gas processing as "facilities that separate and recover natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO2 separated from natural gas streams.....This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes: (1) all processing facilities that fractionate and (2) those that do not fractionate with throughput of 25 MMscf per day or greater." Would a compressor station that moves natural gas to transmission or distribution pipelines that has a dehydration unit for water removal (but does not recover NGLs) be considered a processing facility based on this definition? If the answer to the question above is "NO", then presumably this facility would fall under the definition of transmission compression. As such, would GHG emissions from the dehydrator vent be required to be included in the reporting for the station since this source type is not indicated under		Helpline

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	the natural gas transmission compression sector category?		
	Onshore Natural Gas Processing Industry Segment Definition. CEC/AXPC asserted that "[a]s presently drafted, the unclear and inconsistent final provisions render the rule arbitrary and capricious and contrary to law." CEC/AXPC further stated concerns with the definition for onshore natural gas processing industry segment definition and where the segment differs from onshore natural gas transmission industry segment, and from gathering lines and boosting stations.		Trade Association Materials
4. Clarify in 98.232 (k) that stationary fuel combustion emission from onshore petroleum and natural gas production and natural gas distribution are not reported in Subpart C.	Will the combustion operations not covered by Subpart W have to report under Subpart C?	At least 1 individual	Helpline
5. Addition of parameter *T* in Equation W-1 to account for the total time the pumps are operational.	Pneumatic devices. I suggest that EPA add a size threshold for intermittent natural gas pneumatic devices that will be required to report under 98.233(a). The gas well sites that we visited were very simple sites. One of the typical configurations included a well-head with plunger which fed to a 10 foot tall by 2.5 foot diameter high pressure separator (or to a high pressure and then low pressure separator). The separator feeds liquids to a 400 barrel hydrocarbon liquid tank and a 400 barrel water tank. The gas is sent to the sales line. Because there is no electrical supply to these well pads, natural gas pneumatics are used on the control boxes for equipment with moving parts. These pneumatic devices range from tiny (approximately 5" in diameter and 7" tall) to slightly larger disc-shaped devices (approximately 12" in diameter). I can provide photos if those would be helpful. Each 3-phase separator has 2 pneumatic devices to control the liquid level dump switches. Each 2-phase separator has 1	At least 1 individual	Helpline

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	pneumatic valve on the liquid level dump. Each plunger device has two pneumatic devices, and each well-head has one emergency shut-off pneumatic device. For all of these tiny devices, the venting time is very short and the vented volume is very small. The pumper estimated approximately a half cubic foot of gas might be released on the separator level dump, and this may only happen once every few days. (He demonstrated the actuation of the device and the pneumatic made a short whoosh and was done.) The plunger may operate several times per day but the pneumatic is very small and will vent for approximately 5 seconds. The emergency shut-off devices rarely operate. For all of these types of intermittent pneumatic devices, the provided emission factor 17.4 scf/hour/device will grossly over-estimate emissions, especially given the equation requires application of the emission factor to 8,760 hours per year. Are these small devices meant to be included in the pneumatic device counts? There are also pneumatic pumps that are used very rarely to pump out the tank bottom contents. These are only used occasionally and the application of the provided emission factor of 13.3 scf/hour/pump over the entire year will grossly overestimate the emissions from these devices that operate possibly only once per year. Are these pumps meant to be included in the pneumatic pump counts?		
6. Clarify the definition of *Count* in Equation W-1.	In equation W-1 in 98.233.a, Count is defined as determined in (a)(1) of this section. I believe EPA intended to include (a)(2) in that definition of count. Is that correct?	At least 1 individual	Helpline
7. Clarify in 98.233 (a) that all applicable industry segments can determine the type of pneumatic	Pneumatic Devices. CEC/AXPC asserted that "EPA has not given sufficient consideration to the burden imposed by requiring that the bleed rate of each device be determined in order to count and classify the devices."	At least 2 individuals	Trade Association Material

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device using engineering estimate.	API asserted that “[a]lthough EPA has provided emission factors in Table W-1A that apply to continuous high-bleed, continuous low-bleed, and intermittent bleed pneumatic devices, EPA has not provided guidance on how to classify pneumatic devices according to these three categories.”		Trade Association Materials
8. Addition of parameter *T* in Equation W-2 to account for the total time the pumps are operational.	Under §98.233(c), how are pneumatic pumps that operate only part of the year assessed? [We] believes it unfair to blankly apply the emission factors in Table W-1A to pumps that do not operate all year. Can the "24*365" component of Equation W-2 be modified by the reporter to more accurately reflect operating conditions?	At least 1 individual	Helpline
	Pneumatic devices. I suggest that EPA add a size threshold for intermittent natural gas pneumatic devices that will be required to report under 98.233(a). The gas well sites that we visited were very simple sites. One of the typical configurations included a well-head with plunger which fed to a 10 foot tall by 2.5 foot diameter high pressure separator (or to a high pressure and then low pressure separator). The separator feeds liquids to a 400 barrel hydrocarbon liquid tank and a 400 barrel water tank. The gas is sent to the sales line. Because there is no electrical supply to these well pads, natural gas pneumatics are used on the control boxes for equipment with moving parts. These pneumatic devices range from tiny (approximately 5" in diameter and 7" tall) to slightly larger disc-shaped devices (approximately 12" in diameter). I can provide photos if those would be helpful. Each 3-phase separator has 2 pneumatic devices to control the liquid level dump switches. Each 2-phase separator has 1 pneumatic valve on the liquid level dump. Each plunger device has two pneumatic devices, and each well-head has one emergency shut-off pneumatic device. For all of these tiny devices, the venting time is very short and the vented volume is very small. The pumper estimated approximately a half cubic foot of gas might be released on the separator		

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	level dump, and this may only happen once every few days. (He demonstrated the actuation of the device and the pneumatic made a short whoosh and was done.) The plunger may operate several times per day but the pneumatic is very small and will vent for approximately 5 seconds. The emergency shut-off devices rarely operate. For all of these types of intermittent pneumatic devices, the provided emission factor 17.4 scf/hour/device will grossly over-estimate emissions, especially given the equation requires application of the emission factor to 8,760 hours per year. Are these small devices meant to be included in the pneumatic device counts? There are also pneumatic pumps that are used very rarely to pump out the tank bottom contents. These are only used occasionally and the application of the provided emission factor of 13.3 scf/hour/pump over the entire year will grossly overestimate the emissions from these devices that operate possibly only once per year. Are these pumps meant to be included in the pneumatic pump counts?		

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9. Amend Equation W-4 to eliminate error in GHG estimate due to the approximation in calculation method and subsequent adjustment in parameter definition.	Regarding Equation W-4, for Method 3 for AGR unit CO2 emissions: When outlet NG volume rather than inlet NG volume is measured and used as the input to this equation, the accuracy of W-4 depends on the outlet volume being very close to the inlet volume. This is the case for conventional gas, but it becomes increasingly problematic with high CO2 content in the inlet gas, such as with coalbed methane or possibly in any EOR operation where the CO2 is not captured and reinjected. Although a delta(CO2 conc.) of 0.1 (12% in, 2% out) results in an error of only -1% in the emissions estimate, we don't see any need to accept this error when simply specifying a different equation for this case would give theoretically accurate values. Furthermore, much higher errors could result if the inlet concentration was much higher than 10%, perhaps in some situation you did not anticipate. The attached spreadsheet shows how the percent error varies with delta(CO2 conc.), and also provides a recommended equation for the case where only outlet NG volume is measured. The WCI Reporting Taskgroup would like to allow outlet-only measurement as an option, but we are reluctant to do so if Eq. W-4 would be used for this situation. Perhaps EPA can address this issue in some future amendment to Subpart W.		Helpline

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10. Clarify that use of stripping gas is not limited to natural gas and can be any gas.	This question relates to Subpart W, glycol dehydrator stripping gas. The rule requests: 98.233(e)(1)(vii) Use of stripping natural gas 98.236(c)(4)(i)(C) Whether stripper gas is used in glycol dehydrator Is EPA looking for whether stripping gas is used (which could be dry gas, flash gas, or nitrogen)? Or is EPA looking for whether stripping *natural* gas is used? If it's the latter, does EPA consider dehydrator flash gas to be natural gas (as flash gas does not generally meet the 98.6 definition of natural gas)? In general, I'm trying to understand if this data element will be a "Yes/No" option, or if it will be a "No/Dry Gas/Flash Gas/Nitrogen" option.	At least 1 individual	Helpline
11. Clarify 98.233 (e)(6) by stating that 98.233 (u) and 98.233 (v) must be used to determine CH_4 and CO_2 mass emissions.	This question relates to Subpart W calculation methodology for dehydrator vents. For dehydrators >=0.4 mmcfd, Calculation Methodology 1 98.233(e)(1) specifies that software that "speciates CH4 and CO2 emissions" shall be used. For dehydrators <0.4 mmcfd, Calculation Methodology 2 98.233(e)(2) required equation W-5 which calculates speciated emissions only. However, 98.233(e)(6) says "Both CH4 and CO2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section." Is 98.233(e)(6) supposed to be referring to dehydrators that use desiccant only? If so, the rule should be modified to clarify that this is the intent. Otherwise, the rule does not provide a method for estimating volumetric natural gas emissions,	At least 1 individual	Helpline

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	particularly for dehydrators with <0.4 mmcfd throughput.		
12. Addition of Equation W-11C to determine sonic versus sub-sonic flow	Separate calculations for Subsonic and supersonic flow when both happen during a single completion. API asserted that "[t]he proposed rule did not include a requirement that well completions have separate calculations for subsonic and supersonic flow when both occur during a single completion. The final rule adds this requirement, which is not technically possible."	At least 1 individual	Trade Association Materials
13. Clarify in paragraph 98.233 (1)(i)(A) that vent average flow rate must be determined for each tubing diameter grouping and pressure grouping.	Mapping Wells to Fields. CEC/AXPC asserted that "EPA has not clarified how reporting entities are supposed to map wells to a particular 'field.'" Also, CEC/AXPC asserted that "[w]ithout sufficient clarity regarding what wells are in a particular field, it is difficult for covered sources to know with certainty what gas composition is considered representative for each well."	At least 1 individual	Trade Association Materials
14. 11. Clarification to Equations W-8 and W-9 to account for actual versus standard condition and annual versus event based calculations	There appear to be several issues with equations W-8 and W-9. The equations include a pressure correction, but not a temperature correction The emission term that results from the equations is labeled as actual cubic feet, but the conversions really result in standard cubic feet due to the pressure correction The equations then reference equation W-33 which converts from actual to standard conditions, essentially double correcting for pressure. The units in the second part of the equations are not clear. If HR is an annual value (sales flow rate/hr per year), than subtracting 1 hour or 30 minutes from annual hours is meaningless. If HR is on an event basis or daily basis, then the equations are missing a summation. Please correct or clarify the units for these equations.	At least 1 individual	Helpline
	I am finding errors in the EPA's Equation W-9 to calculate emissions from		

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	each well venting to the atmosphere for liquids unloading w/ plunger lift assist. These same errors are also in Equation W-8. They are hard to explain, but "EPA's technical experts" should be able to follow the explanations below. 1. It states that the answer is the gas emissions at actual conditions, in cubic feet per year. This is incorrect. The factor of 0.00037 that is used includes dividing by 14.7 psia, which converts the volume to standard pressure. The first part of the equation calculates the volume of the tubing, but then it multiplies by the sales pressure and divides by 14.7 (built in the 0.00037 factor). This takes the volume in the tubing and converts it to standard pressure. To get it to standard conditions, only the temperature needs to be considered since your equation already calculates the gas volume at standard pressure. Also, the second half of your equation (which also has errors that I discuss below) uses sales flow rate which, of course, is in standard conditions already --- so the resulting answer is obviously going to be in standard conditions. 2. The first part of the equation calculates the tubing volume and converts it to standard pressure, as discussed above. This result is then multiplied by the number of vents per year to give a volume vented for the year. Then we are to add the second part of the equation to that yearly volume. The problem is the second part of the equation is (or should be) calculating an extra volume per venting cycle, not a yearly volume. I am assuming that "HR" is the hours left open during a venting cycle, because it would not make sense if that was in hours per year. The EPA's assumptions (which I don't agree with) are that if a well on plunger lift vents to atmosphere during one of its plunger cycles, it vents the entire volume of the tubing in a half hour, then any venting over a half hour, the well is venting at the sales flow rate. The problem is the equation that the EPA provided does not		

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	calculate this correctly.		
15. Changing requirements to be applicable to sub-basin category and well type (horizontal vs. vertical) combination.	Mapping Wells to Fields. CEC/AXPC asserted that "EPA has not clarified how reporting entities are supposed to map wells to a particular 'field.'" Also, CEC/AXPC asserted that "[w]ithout sufficient clarity regarding what wells are in a particular field, it is difficult for covered sources to know with certainty what gas composition is considered representative for each well."	At least 1 individual	Trade Association Materials
16. 12. Clarify that the requirements set forth in 98.233 (g)(3) and 98.233 (g)(5) are applicable to both completions and workovers from hydraulic fracturing	The calculation methodology for gas well venting during completions and workovers from hydraulic fracturing [98.233(g)] allows for the subtraction of gas recovered to sales by use of the variable SG in Equation W-10. However, 98.233(g)(3) refers to only the volume of "completion gas", not the volume of "completion or workover gas". Similarly, 98.233(g)(5)(i) notes that the variable SG is for the magnitude of emissions captured using "reduced emissions completions" not "reduced emissions completions or workovers". As both workovers and completions may involve reduced emissions approaches, please confirm that the variable SG is to represent the volume of gas routed to sales during both workovers and completions.	At least 1	Helpline
17. Clarify the parameter definitions for *f*, V_p, and T_p in Equation W-13 to make it applicable to a sub-basin category instead of field.	Mapping Wells to Fields. CEC/AXPC asserted that "EPA has not clarified how reporting entities are supposed to map wells to a particular 'field.'" Also, CEC/AXPC asserted that "[w]ithout sufficient clarity regarding what wells are in a particular field, it is difficult for covered sources to know with certainty what gas composition is considered representative for each well."	At least 2 individual	Trade Association Materials
	Field level reporting for onshore petroleum and natural gas production. API asserts that "[t]his level of reporting is problematic when applied to new requirements of the final rule. For the same reasons, it remains problematic when applied to those requirements in the proposed rule that		Trade Association Materials

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	remain in the final rule."		
18. Clarify that emergency blowdowns are included in the rule.	(i) *Blowdown vent stacks.* **Clarify "exempt volumes; events to include (i.e., "significant" blowdowns for maintenance or safety), and add another calc (operator selects calc to use) where events are calculated and summed.** Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to the atmosphere **<u>to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance</u>** (excluding depressurizing to a flare, over-pressure relief, ~~operating pressure control venting and~~ blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:		Trade Association Materials
19. Addition of Equation W-14B to allow emission to be calculated on a per occurrence basis and allow a correction for blowdowns that are not brought down to atmospheric pressure.in w	$E_{s,n} = \sum_{i=1}^{N}\left(V_{v,i}\left(\frac{(459.67+T_s)(P_{a,0,i}-P_{a,f,i})}{(459.67+T_{a,i})P_s}\right)\right)$ **<u>(Eq.-W-14b)</u>** **<u>Where:</u>** **<u>$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.</u>** **<u>N = Number of blowdowns in the calendar year.</u>** **<u>$V_{v,i}$ = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) in cubic feet.</u>** **<u>Ts = Temperature at standard conditions (°F).</u>** **<u>Ta,i = Temperature at actual conditions (estimated) for event "i" in</u>**		Trade Association materials

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	the blowdown chamber (°F). **P_s = Absolute pressure at standard conditions (psia).** **$P_{a,0,i}$ = Absolute pressure at actual conditions at the start of event "i" in the blowdown chamber (psia).** **$P_{a,f,i}$ = Absolute pressure of natural gas at actual conditions at the end of event "i" in the blowdown chamber (psia) ((if the equipment is purged using non-GHG gases then Pa,f,i = 0).**		
20. Amend 98.233 (k) by allowing reporters to measure the emission from the tank vent directly instead of monitoring for emission using an optical gas imaging device	(k) *Transmission storage tanks.* **Correct reference to flaring in intro, add monitoring method flexibility, and delete reference to flaring calculation (broadly addressed in §98.232(j) and not needed in this section)** For condensate storage tanks, either water or hydrocarbon, ~~without vapor recovery or thermal control devices~~ in onshore natural gas transmission compression facilities calculate CH_4, **and** CO_2 ~~and N_2O (when flared)~~ annual emissions from compressor scrubber dump valve leakage as follows: (1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods ~~set forth~~ in §98.234(a)(1) **or by directly measuring the tank vent using a flow meter, calibrated bag, or high volume sampler according to methods in §98.234(b) through (d)** for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in §98.234(a)(5). (2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to **estimate** ~~quantify~~ emissions:		Trade Association materials

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	(i) Use a meter, such as a turbine meter, **calibrated bag, or high flow sampler** to estimate tank vapor volumes according to methods ~~set forth~~ in §98.234(b) **through (d)**. If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. **If the vent is directly measured for five minutes under section (1) to detect continuous leakage, this serves as the measurement. If a leak of 3.1 SCF per hour or greater is measured, a leak is detected and must be reported.** (ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in §98.234(a)(5). **(3)**(~~iii~~) **Calculate both CH4 and CO2 volumetric and mass emissions using calculations in (u) and (v) of this section, and using** ~~Use~~ the appropriate gas composition in paragraph (u)(2)(iii) of this section **or the gas composition allowed in §98.232(m)**. **(4)**(~~3~~) If the leaking dump valve(s) is repaired following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired. ~~(4) Calculate emissions from storage tanks to flares as follows:~~ ~~(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1)of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.~~		

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	~~(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.~~		
21. Clarify the GHG mole percentage of the natural gas liquids should be used for onshore natural gas processing plants that solely fractionate a liquid stream.	EPA may not be aware that facilities which are designed solely to fractionate a liquid stream will not have a de-methanizer. However, this same facility may flare natural gas. Therefore, IF: 1) facilities which receive a natural gas liquid stream for fractionation are regulated under the Gas Processing Segment of Subpart W (see email "Question on Natural Gas Liquids Fractionators" submitted by Stephanie Jones of URS to ghgmrr@epa.gov on 11/24/10), AND 2) the facility does not have a continuous gas composition analyzer on the gas to the flare, AND 3) measurements of the flare gas which are not made with a continuous GC analyzer cannot be used for compliance with 98.233(n)(2)(ii) (see email "Question on Alternative Composition Sampling for Flare Stacks" submitted by Stephanie Jones of URS to ghgmrr@epa.gov on 11/19/10), Please confirm that engineering estimates may be used in this situation to determine the flare gas composition under 98.233(n)(2)(ii) when the stream going to the flare is natural gas.	At least 1 individual	Helpline
22. Clarify that GHG_i for onshore natural gas processing does not need to be determined in Equation W-31 because 98.233 (r) is not applicable to that source category	98.236(c)(15)(ii)(A). The source categories in 98.230(a)(3) and (a)(4) are listed under this reporting section, but are not required to use population count calculations, as far as I can tell. Please confirm. I have the following questions about the parameter "GHGi" in Subpart W for pneumatic devices, pneumatic pumps, and equipment leaks: Question -For equipment leaks, how and at what frequency should GHGi in Equation W-31 be determined for onshore petroleum and natural gas	At least 1 individual	Helpline

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	production and processing facilities? Note that the equation does not refer to 98.233(u), so it is not clear how GHGi should be determined and at what frequency.		
23. Amend Equation W-32 by adding a conversion factor to make it hourly emissions.	I am developing a spreadsheet for APGA members to perform subpart W calculations for natural gas distribution systems and found what I think is an error in the equations for estimating fugitive emissions from non-custody transfer gate stations; equations W-31 and W-32. Equation W-31 is as follows: Es,i = Counts * EFs *GHGi *Ts EFs is the emission factor in scf/hr and Ts is the number of hours of operation during the calendar year. For non custody transfer gate stations EFs is calculated using Equation 32 which is EF = Sum (Es,i/Count) (Eq. W-32) Where Es,i is the annual estimated emissions from custody transfer gate station and count is the number of meter runs. I think EPA's intent was to assume fugitive emissions from non-custody transfer gate stations was the same as fugitive emissions from custody transfer gate stations, which isn't a bad assumption, but equation W-32 produces an emission factor, EFs, that is the average annual fugitive emissions per meter run at custody transfer gate stations rather than an hourly emission factor required by Equation W-31. As a result, the estimated emissions from non-custody transfer gate stations are 8,760 times greater than estimated emissions from custody transfer gate stations.	At least 2 individual	Helpline

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	Equation W-32 should be EF = Sum (Es,i/(Count*Ts)) so that the calculated emission factor is an hourly emission factor rather than an annual emission factor.		
	This question pertains to the calculation method for an LDC facility's non-custody transfer gate stations. In the rule, equations W-31 and W-32 are to be utilized to calculate emissions from these sources. The EF as calculated in W-32 has units of scf/meter-year. If the vast majority of a company's non-custody transfer gate stations which are above grade are purely regulating stations (ie no meters), then are the emissions from these stations required to be reported? In the manner in which the equations are written now, it suggests that emissions from these sources are not covered. Please confirm or explain.		
	New emission factor formulas are confusing or contain math errors that vastly inflate emission estimates. AGA asserted that the "[t]he new emissions factor equations W-30, W-31 and W-32 in the final rule are confusing. Since these formulas were not included in the proposed rule, AGA did not have an opportunity to comment on them."		Trade Association Materials
	Errors in Calculations. Southwest Gas Corporation asserted that the USEPA published errors in equations in 40 CFR 98.233, namely equation W-32.		Trade Association Materials
24. Clarify how meters/piping should be counted in Equation W-32.	When using Table W-1B to determine counts for major onshore natural gas production equipment, how would a facility determine counts of "meters/piping"? Specifically, how should "piping" be counted?	At least 3 individuals	Helpline
	Under subpart W equipment leaks for onshore production, how do we apply the "meters/piping" count? Is there one of these "meter/piping" counts per sales flow meter, or one per site (such as one per well pad site and one per central facility)?		Helpline
	Please clarify how "meters/piping" are to be quantified in order to apply the default average component counts in Table W-1B.		Helpline

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	• Is there simply one "meters/piping" count per well pad location? • Does a well pad with only a wellhead (no separator, no tanks) still get a "meters/piping" count because there is piping from the wellhead? • Is this count only for piping associated with meters, and if so does any amount of piping associated with a single meter count as one "equipment" unit? • Does a particular length of piping count as one unit of "equipment"?		
	For underground natural gas storage we are trying to determine how to calculate equipment leaks as specified in 98.232(f)(5). Pursuant to 98.233(r) we are allowed to use Equation W-31. However, for the "Count" in equation W-31 it refers to using Tables W-1B and W-1C, but these tables are for Default Average Components Counts for Onshore Natural Gas Production and Major Crude Oil Production Equipment, respectively. Do we use these tables for underground natural gas storage?		Helpline
	Non custody transfer city gate station terminology. AGA asserted that “[s]everal provisions in the Subpart W rule and preamble seem to imply that a ‘non-custody-transfer city gate station’ will always have a meter.”		Trade Association Materials
25. Clarify the paragraphs 98.233 (t)(1) and (t)(2)	(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section**, with actual pressure and temperature** determined by engineering estimate based on best available data unless otherwise specified. (1) Calculate natural gas volumetric emissions at standard conditions ~~by converting actual temperature and pressure of natural gas~~ emissions to standard temperature and pressure of natural gas using **actual natural gas emissions temperature and pressure, and** Equation W–33 ~~of this section~~. $E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$ (Eq. W-33)		Trade Association Materials

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	Where: $E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet. $E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet. T_s = Temperature at standard conditions (°F). T_a = Temperature at actual emission conditions (°F). P_s = Absolute pressure at standard conditions (psia). P_a = Absolute pressure at actual conditions (psia). (2) Calculate GHG volumetric emissions at standard conditions ~~by converting actual temperature and pressure of GHG emissions to standard temperature and pressure~~ using **actual GHG emissions temperature and pressure, and** Equation W–34 ~~of this section~~. $E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$ (Eq. W-34) Where: $E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet. $E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet. T_s = Temperature at standard conditions (°F). T_a = Temperature at actual emission conditions (°F). P_s = Absolute pressure at standard conditions (psia). P_a = Absolute pressure at actual conditions (psia).		

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26. Clarify the introductory paragraph to 98.233 (u)	(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section**, with mole fraction of GHGs in the natural gas** determined by engineering estimate based on best available data unless otherwise specified. (1) Estimate $CH_4$and CO_2emissions from natural gas emissions using Equation W–35 of this section. $E_{s,i} = E_{s,n} * M_i$ (Eq. W-35) Where: $E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet. $E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet. M_i = Mole fraction of GHG_i in the natural gas.		Trade Association Materials
27. Clarify that an annual average gas composition based on best available analyses in each of the sub-basin categories can be used if a gas composition analyzer is not available	Use of gas composition based on available sample analysis for reporters without continuous gas composition analyzer. API asserts that "EPA should resolve the ambiguity created by the current language."		Trade Association Materials
28. Add default gas compositions for onshore natural gas transmission, underground natural gas storage, LNG storage, LNG import and export	(2) For Equation W–35 of this section, the mole fraction, Mi, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section. (i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas,		Trade Association Materials

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facilities, and natural gas distribution facilities	you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field. (ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b). (iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities **or the composition in §98.232(m)(1)**. (iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities **or the composition in §98.232(m)(1)**. (v) GHG mole fraction in natural gas stored in LNG storage facilities **or the composition in §98.232(m)(1)**. (vi) GHG mole fraction in natural gas stored in LNG import and export facilities.		

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	(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities **or the composition in §98.232(m)(1)**.		
29. Clarify the introductory paragraph to 98.233 (v)	(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent ~~at standard conditions~~ by converting the GHG volumetric emissions **at standard conditions** into mass emissions using Equation W–36 of this section.		Trade Association Materials
30. Clarify the definition of $Mass_{s,i}$, $E_{s,i}$, and by ρ_i adding N_2O	$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3}$ (Eq. W-36) Where: $Mass_{s,i}$ = GHG i (either CH_4**,** or CO_2 **or N_2O**) mass emissions at standard conditions in metric tons CO_2e. $E_{s,i}$ = GHG i (either CH_4**,** or CO_2 **or N_2O**) volumetric emissions at standard conditions, in cubic feet. ρ_i = Density of GHG i. Use 0.0538 kg/ft^3 for CO_2 and N_2O, and 0.0196 kg/ft^3 for CH_4 at 68 °F and 14.7 psia or 0.0530 kg/ft^3 for CO_2 and N_2O, and 0.0193 kg/ft^3 for CH_4 at 60°F and 14.7 psia. GWP = Global warming potential, 1 for CO_2, 21 for CH_4, and 310 for N_2O.		Trade Association Materials
31. Clarify the requirements of calibrated bagging in 98.234 (c).	(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures **and below the maximum temperature specified by the vent bag manufacturer** such that ~~it~~ **the bag** is safe to handle**.** ~~and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and~~ **The bag must be of sufficient size that** the entire emissions volume can be encompassed for measurement.		Trade Association Materials

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Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
32. Clarify that 98.233 (t) can be used to convert emissions at actual conditions to standard conditions for high volume samplers.	(d) Use a high volume sampler to measure emissions within the capacity of the instrument. (1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source. (2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual. **(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t).** (~~3~~**4**) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v). (~~4~~**5**) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.		Trade Association materials

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Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
33. Clarify that emissions from gas routed flares must be reported separately from emissions vented directly to the atmosphere throughout 98.236(c) and in the introductory paragraph to 98.236.	Well testing venting and flaring clarification. CEC/AXPC asserted that "[t]he final rule is unclear regarding the requirement to report emissions from well testing venting and flaring."	At least 2 individuals	Trade Association Materials
34.	98.236(c)(11)(iii). This only requires reporting of the flared gas. No reporting of vented gas?		Helpline
35. Clarify the level of reporting (i.e. facility level, by equipment) in 98.236 (c).	Number of plunger lifts and average casing diameter in inches. API asserted that "[t]he final rule adds 40 CFR 98.236(c)(5) requirements to report the number of plunger lifts and average casing diameter in inches by field. The difficulty with these additions is not with the requirement for counting plunger lifts and noting casing diameter, but that reporting must take place at the field level."	At least 1 individual	Trade Association Material
	Basin level reporting for onshore petroleum and natural gas production. API asserted that "[t]his broad definition of onshore production facility is impractical. Subpart W imposes reporting requirements on over 22,000 entities operating hundreds of thousands of wells and millions of pieces of equipment scattered over hundreds of thousands of square miles."		Trade Association Material

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Summary Of Questions And Issues From The EPA Helpline And Trade Associations Being Resolved By The Proposed Technical Corrections And Other Amendments

Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
36. Amend the definition of "facility with respect to natural gas distribution for purposes of this subpart and subpart A".	How should M&R Stations that are jointly owned, in whole or in part, between an LDC and an interstate pipeline company (e.g. Transco, Texas Eastern) be treated in terms of Subpart W reporting by the LDC? It seems reasonable that the LDC is only responsible for reporting for the affected equipment that the LDC owns and operates, and that the interstate pipeline company is responsible for reporting for the affected equipment that the LDC owns and operates.	At least 1 individual	Helpline
37. Provide a definition for associated with a single well-pad	What does "associated with a well pad and CO2 EOR operations" mean in the definition of a facility (98.238)? a. For example are gathering booster compressors associated with a well pad? b. b. How do you handle equipment (dehydrators) located on individual well-pads but owned/operated by a gathering/collection 3rd party company and paid as part of a "tolling" agreement with a $/mcf gathering fee?	At least 3 individual	Helpline
	Subpart W repeatedly refers to sources of emissions "on a well pad or associated with a well pad". But neither Subpart W nor Subpart A include definitions for the terms "well pad" or "associated with a well pad". Assume an oil and gas production facility consists of, say, a 1000 acre area throughout which 50 or more wells (well pads?) are scattered, but with no equipment located at the wells. The wells produce via pipelines to one or more central sites where produced fluids from the wells are processed (for sale, re-injection, etc.). The central sites consist of separators, combustion equipment, storage tanks, and other process equipment, but no wells or "well pads". Is the equipment located at the central processing sites considered equipment that is "associated with a well pad" and, thus, included in the definition of "facility" under Subpart W?		Helpline

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Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
	In the definition of an Onshore Petroleum and Natural Gas Production facility, it says....."on a well pad or associated with a well pad (including compressors, generators, or storage facilities)". Can you more specifically define "associated with a well pad"? What we need to know is if that means the "included" equipment is only applicable if it is AT that exact well pad location OR does it mean that "included" equipment is applicable if it is in any way connected to the production of the gas pumped from the well pad (even if it is NOT located at the same location as the well pad).		Helpline
	I'm trying to understand the boundaries of our facility under Subpart W. Our project consists of 2 gravel pads separated by 8 miles. One pad (well pad) contains multiple wells, a drilling rig, and other support equipment. Three-phase production (oil/gas/water) from the well pad is transported 8 miles via flowlines to the second pad. The second pad (tie-in pad) provides power and other utilities to the well pad and is a tie-in point to third-party facilities. The tie-in pad contains metering equipment (including a production separator), power generation, gas compression for natural gas EOR injection (separate from the production stream), and other support equipment. Processing of the three-phase production is done entirely by a third party several miles downstream of the tie-in pad. My interpretation of Subpart W is that the well pad is an onshore petroleum and natural gas production facility but that the tie-in pad doesn't fall under any of the categories. The well pad should be evaluated for applicability under Subparts C and W and, separately, the tie-in pad for applicability under Subpart C.		Helpline

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Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
	Please let me know if I've understood the rule correctly or if you need any additional information.		
	Definitions to Industry Categories. API asserted that the “[a]ltered final rule creates ambiguity as to whether certain facilities are included in the production category, excluded as gathering or booster stations, or included under the gas processing category.”		Trade Association Materials
38. Provide a definition of transmission-distribution transfer station	Please provide a definition of "custody transfer city gate" and "non-custody transfer city gate station" as used in 98.232(i)(1) and (2). These definitions should be incorporated into the rule.	At least 4 individuals	Helpline
	For local distribution companies, please verify that emissions do not need to be calculated and reported for above-ground non-custody transfer city gate stations that are solely defined as regulating stations and do not contain any metered runs.		Helpline
	Please explain the difference between a custody and non-custody transfer city gate station. Thank you.		Helpline
	If I have a distribution "facility" that does not own or operate any above ground M&R at custody transfer city gate stations, how do I calculate the EF required for above ground M&R at non-custody transfer city gate stations? There is no other option for calculating emissions for this emission source.		Helpline
	Custody transfer city gate station terminology. AGA asserted that the term “custody transfer city gate station” in subpart W was unclear and needed clarification.		Trade Association Materials
	Terms in Subpart W. Petitioner asserted that “[t]he USEPA’s final rule fails to provide clear definitions that can be used uniformly throughout the natural gas distribution industry.”		Trade Association Materials
39. Provide a definition of metering-regulating station	Please provide a definition of "custody transfer city gate" and "non-custody transfer city gate station" as used in 98.232(i)(1) and (2). These definitions should be incorporated into the rule.	At least 3 individuals	Helpline

Appendix A Summary Of Questions And Issues From The EPA Helpline And Trade Associations Being Resolved By The Proposed Technical Corrections And Other Amendments			
Technical Issue	**Question Submitted to EPA**	**Type and approximate number of submittals**	**Reference (Helpline or Trade Association materials)**
	For local distribution companies, please verify that emissions do not need to be calculated and reported for above-ground non-custody transfer city gate stations that are solely defined as regulating stations and do not contain any metered runs.		Helpline
	If I have a distribution "facility" that does not own or operate any above ground M&R at custody transfer city gate stations, how do I calculate the EF required for above ground M&R at non-custody transfer city gate stations? There is no other option for calculating emissions for this emission source.		Helpline
	Terms in Subpart W. Petitioner asserted that "[t]he USEPA's final rule fails to provide clear definitions that can be used uniformly throughout the natural gas distribution industry."		Trade Association Materials
40. Provide definition of "natural gas".	Pipeline Quality Natural Gas. CEC/AXPC asserted that "[t]here is not a clear and unambiguous definition in the final rule for 'pipeline quality' natural gas."		Trade Association Materials
41. Provide a definition of the transmission pipeline	Gathering and Boosting are not defined, leaving a lot up to interpretation. 'Transmission pipeline' is defined rather loosely. I have a list of 20 small compressor stations that must be classified with very little guidance. If the goal is to capture only very large compressor stations introducing gas into interstate pipelines, that term should be used or minimum pipeline pressures and diameters should be named. Does the term 'cross country pipeline' exclude intrastate pipelines? The natural gas collection pipeline network is extensive and complicated in some parts of the country. Tiny boosting compressor stations not related to the very biggest of transmission pipelines should not have to go to the expense of performing the optical leak detection and flow rate sampling exercises. Alternately, a compressor engine horsepower size cutoff should be named. (Or total aggregate compressor horsepower at a single facility.)	At least 2 individuals	Helpline

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Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
	The definition of the onshore natural gas transmission compression includes "any stationary combustion of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage." How does EPA currently define transmission pipelines? Is this definition consistent with how any other federal agencies define transmission? For example, DOT defines a transmission line as follows: Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.		Helpline
	Excluding Boosting Stations. CEC/AXPC asserted that "[t]he final rule fails to distinguish between a boosting station, which is exempt, and an 'onshore natural gas transmission compression facility' which must report under the rule."		Trade Association Materials
	Onshore Natural Gas Transmission Compression Industry Segment Definition. CEC/AXPC asserted that "[a]s presently drafted, the unclear and inconsistent final provisions render the rule arbitrary and capricious and contrary to law." And "The term 'onshore natural gas transmission compression' means a stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines or into storage. 40 C.F.R. §98.230(a)(4). A transmission compressor station can include equipment to separate liquids or dehydrate natural gas Id. However, according to the final rule this source category does not include gathering lines and boosting stations."		Trade Association Materials
42. Provide a definition for tubing systems	Section 98.233(r) describes the GHG calculation methodology for equipment leaks for onshore oil and gas production facilities. It says, in part, "Tubing systems equal or less than one half inch diameter are exempt	At least 1 individual	Helpline

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Technical Issue	Question Submitted to EPA	Type and approximate number of submittals	Reference (Helpline or Trade Association materials)
	from the requirements of paragraph (r) of this section and do not need to be reported." The regulation does not define the term "tubing systems". Are valves, guages, plugs, etc., that are themselves larger than one half inch but are associated with piping that is equal or less than one half inch also exempt?		
43. Provide a definition for well testing venting and flaring	Currently there is no definition provided for well testing. Please provide comment on how well testing is different than well workovers and completions.	At least 6 individuals	Helpline
	Does EPA's have specific definitions for the following equipment used by subpart W sources? • Natural gas driven pneumatic pump • Well testing venting and flaring • Associated gas venting and flaring from produced hydrocarbons Specifically for gas venting and flaring how does the GHG reporting rule distinguishes between the two?		
	Currently there is no definition provided for well testing, which makes it unclear for reporters to understand the venting emissions they are supposed to capture in regards to this emission source. This lack of a definition also confuses Section 98.233(m) whereby associated gas venting and flaring emissions should be calculated "not in conjunction with well testing." There is also no definition of associated gas or further clarification from EPA on what types of emission sources should be reported here. Please provide explicit clarification on the situations which EPA understands to be associated gas venting so that we may appropriately understand how to apply the calculation methodology provided.		
	For Well Testing Venting and Flaring, when should we be conducting these measurements? What is the EPA considering the 'testing period'? What type of testing does this include?		
	• What is the difference between associated well venting and flaring and		

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Technical Issue	**Question Submitted to EPA**	**Type and approximate number of submittals**	**Reference (Helpline or Trade Association materials)**
	well testing venting and flaring? EPA definitions would help.		
	• EPA definition for "well testing". Would this be considered the flow back period; and		

APPENDIX B

Summary of Issues From Internal Review Being Addressed by Proposed Amendments

Not all corrections and other amendments correspond directly to questions that were raised by reporters. The need for some corrections and other amendments were identified as a result of internal EPA review. Below is a summary of the issues that have been raised from the EPA's review of Subpart W of Part 98 which are being addressed by the proposed 2011 revisions package.

Overarching Changes

- Correcting grammar errors in Subpart W to clarify the meaning and intent of paragraphs.
- Correcting Equation W-8, W-9, W-10, W-12, W-13, W-14A, W-21, W-30, and W-39 by clarifying the summation operator to make it mathematically functional.
- Clarifying, where necessary, that emissions, counts, and other requirements must be reported on a sub-basin category basis instead of on a field.

Changes to 98.230

- Clarify that EOR operations using natural gas is also included in the industry segment definition for onshore petroleum and natural gas production.
- Clarify that only source types on a single well-pad or associated with a single well-pad need to report under onshore petroleum and natural gas production.
- Clarify that the transmission industry segment includes transportation of gas from other transmission compressors and to LNG storage facilities.
- Clarify the natural gas distribution industry segment definition.

Changes to 98.232

- Clarify in paragraph 98.232 (c)(22) that the industry segment is petroleum and natural gas production and not onshore production.
- Clarify in paragraph 98.233 (c)(22) that facility, with respect to onshore petroleum and natural gas production, is as defined in 98.238.
- Clarify that CO_2, CH_4, and N_2O emissions must report for each of the sources types listed under 98.232 (e) through (i).
- Clarifying the use of the term above and below grade in 98.232 (i).
- Changing custody transfer to transmission-distribution transfer and non-custody transfer to metering-regulating station in 98.232 (i).
- Addition of equipment leaks from vaults at below grade transmission-distribution transfer stations under 98.232 (i).
- Removing and reserving the paragraph 98.232 (j).
- Clarify that combustion emission for onshore petroleum and natural gas production and natural gas distribution must be reported under Subpart W and not Subpart C (General Stationary Fuel Combustion Sources).

Changes to 98.233

- Clarify the introductory paragraph to 98.233 (d) by stating that any Calculation Methodology under this paragraph can be used as applicable.

- Clarify the paragraph 98.233 (d)(1) to clarify the CEMS requirements that must be used to determine CO_2 emissions.
- Correcting Equation W-4 in Calculation Methodology 3 and removing the parameter α.
- Clarify the parameter definition for 1000 in Equation W-5.
- Amend the emission calculation methodology for liquids unloading by clarifying Equation W-7 so that $E_{a,n}$ and $T_{h,t}$ is applicable to wells of the same pressure grouping at and same tubing diameter.
- Amend the emissions calculation methodology for gas well venting during completions and workovers from hydraulic fracturing through: changes to Equation W-10; addition of newly assigned Equation W-12; and specifying the number of measurements depending on the number of completions and workovers.
- Clarify that methane is a possible hydrocarbon going to a flare in 98.233 (n)(2)(iii).
- Amend 98.233 (n) to allow the use of CEMS.
- Clarify the parameter definition of MT_m in Equation W-24.
- Clarify the GHG_i factor in Equation W-30 for the industry segments listed under 98.230 (a)(4), 98.230 (a)(5), 98.230 (a)(6), 98.230 (a)(7), 98.230 (a)(8).
- Clarify in paragraph 98.233 (q)(8) that leak detection is only required at above grade stations that qualify as transmission-distribution transfer stations.
- Clarify the emission factors that must be used for sources in natural gas distribution in 98.233 (r)(6).
- Clarify Equation W-32 by adding the term "meter/regulator run" and the GHGs that need to be reported.
- Clarifying the requirement set forth in 98.233 (z).

Changes to 98.234

- Amending the requirements for optical gas imaging instruments from 98.234 (a)(4) by moving it into 98.234 (a)(1).
- Adding the applicable references to the *Alternative work practice for monitoring equipment leaks* under 98.234 (a)(1).
- Clarify that acoustic stethoscopic devices designed to detect through valve leakage can be used to determine leaking and non-leaking devices in 98.234 (a)(5).

Changes to 98.236

- Clarify that the annual emissions from each industry segment must be reported under 98.236 (a).
- Clarify the natural gas distribution industry segment in 98.236(a)(8).
- Clarify the reporting requirements for the offshore petroleum and natural gas production industry segment.
- Clarify that facilities that operate under more than one industry segment are required to report emissions under majority use segment.
- Clarify that the quantity of recovered gas must be reported separately.
- Clarify that emissions from CO_2, CH_4 and N_2O emission must be reported separately throughout 98.236(c).
- Clarify that emissions from high-bleed pneumatic devices, intermittent bleed pneumatic devices, low-bleed pneumatic devices must be reported separately on a facility level.

- Clarify that emission from pneumatic pumps must be combined but that CO_2 and CH_4 emissions must be separated.
- Clarify that the reported CO_2 concentration can be an annual average for the AGR unit.
- Clarify that an annual quantity is required for recovered emissions transferred outside of the facility and emissions from an AGR unit.
- Additional reporting requirement for AGR units: Unique ID name or ID number for AGR unit; and the Calculation Methodology used for determining emission from AGR units.
- Clarify that the concentration of CH_4 and CO_2 in wet natural gas must be reported for glycol dehydrators.
- Addition of unique ID name or ID number reporting requirement for glycol dehydrator unit.
- Clarify that the type of vent gas control must be reported for glycol dehydrators.
- Clarify that annual emissions from absorbent dehydrators must be reported.
- Addition of the reporting requirement to report the diameter, depth, and pressure of the each well selected to represent emission in that tubing size and pressure combination.
- Clarify the reference to Equation W-12 in 98.236 (c)(6)(i)(B) and (c)(6)(i)(D).
- Clarify that the number blowdowns per unique volume must be reported.
- Addition of unique ID name or ID number reporting requirement for blowdown vent.
- Addition of unique ID name or ID number reporting requirement for onshore production storage tanks.
- Clarifying the reference to 98.236 (c)(8)(ii)(B) and (c)(8)(ii)(C) in 98.236 (c)(8)(ii)(D).
- Addition of unique ID name or ID number reporting requirement for transmission storage tanks.
- Clarify that uncombusted CH_4, uncombusted CO_2, combusted CO_2, and N_2O emissions must be reported separately for flares.
- Addition of unique ID name or ID number reporting requirement for flare stacks.
- Report whether emissions from flares were determined using CEMS.
- Clarify that a range should be reported for the concentration of CH_4 and CO_2 for onshore natural gas processing.
- Addition of 98.233 (a)(8) source category under 98.236 (c)(15)(ii)(A).
- Amending 98.233(c)(16) by changing custody transfer gate station to T-D transfer station and M&R station to metering-regulating stations.
- Addition of unique ID name or ID number reporting requirement for EOR pumps.
- Addition of the requirement to report the average API gravity, average gas to oil ratio, and average low pressure separator pressure for each sub-basin category.

Changes to 98.237

- Addition of the requirement to include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under Subpart W.

Changes to 98.238

- Amend the definition of “facility with respect to onshore petroleum and natural gas production for purposes of this subpart and subpart A”.
- Amend definition of “Farm taps”.
- Provide definition of “forced extraction of natural gas liquids”.
- Provide definition of “distribution pipeline”.

- Provide definition of “flare”.
- Remove the definition of “field”.
- Provide definition of “horizontal well”.
- Provide definition of “pressure groupings”.
- Provide definition of “sub-basin category”.
- Provide definition of “tubing diameter groupings”.
- Provide definition of “vertical well”.

Changes to Tables

- Clarifying Table W-7 by changing the term “custody transfer city gate station” to “transmission-distribution gate station”; changing M&R to “metering-regulating” station; and deleting footnote 1.

APPENDIX C

Percent Gas Composition for Natural Gas Transmission Compression, Underground Natural Gas Storage, Liquefied Natural Gas (LNG) Storage, LNG Import and Export, and Natural Gas Distribution Industry Segments for Methane and Carbon Dioxide

EPA set the default mole fraction of methane (CH_4) and carbon dioxide (CO_2) at 95% and 1%, respectively, for the onshore transmission compression, underground natural gas storage industry segment, LNG natural gas storage, LNG import and export, and natural gas distribution industry segment. Industry petitioned for the default mole fraction because the CH_4 and CO_2 composition of "pipeline quality" gas does not vary significantly for these industry segments. This memorandum describes the analysis that was conducted to determine whether the default mole fraction of CO_2 and CH_4 is valid.

Background

§98.233 (u) Subpart W, using Equation W-35, converts natural gas emission into its respective greenhouse gas components. Equation W-35 converts natural gas emission to its respective components through the parameter M_i, which is the mole fraction of CO_2 and CH_4. In the November 2010 Finalized Rule, M_i was determined using a known composition of transmission pipeline natural gas. Interstate Natural Gas Association of America (INGAA), in their petition, suggested that a default mole fraction composition of 95% and 1% for CH_4 and CO_2, respectively, adequately represents natural gas composition in the natural gas transmission and storage segments of subpart W. As a simplification, EPA is proposing the use of the default transmission pipeline quality composition for all segments downstream of the transmission segment, which would encompass underground storage, liquefied natural gas (LNG) storage, LNG import and export, and the natural gas distribution industry segments. EPA notes that a portion of the natural gas from production goes straight to Local Distribution Companies (LDC)s. Also, some of the LNG imported does not necessarily conform to pipeline standards in terms of composition, i.e. the same heat content can be achieved from varying compositions of the inherent hydrocarbon components. However, EPA notes that for the purposes of this rule these variations are not of consequence, because the majority of the gas conforms to the suggested default mole fraction.

Determination of CO_2 and CH_4 Composition

Methodology

Pipeline and Gas Journal annually publishes market data on the top 500 transmission companies in the United States. Several transmission companies report their gas compositions on their company websites. To conduct the analysis, EPA extracted the gas composition data from the largest transmission companies that account for 53% of the gas transported through transmission pipelines in the U.S. The compositions presented on a specific day were assumed to be representative of the gas composition during a whole year of operation for the company. EPA determined the weighted average composition of methane using dekatherms as the weighting parameter.

Results

The weighted mole fraction of CH_4 and CO_2 in the natural gas was 95.8% and 1.12% respectively. The maximum CH_4 content observed was 96.79% and the minimum was 93.40%. The maximum CO_2 content observed was 1.71% and the minimum was 0.64%.

Table 1: CH_4 and CO_2 mole fraction reported by the largest transmission companies.

	2009 Gas Throughput (Dth/y) 1000	2009 Transmission Miles	CH_4 Mole Fraction Natural Gas	CO_2 Mole Fraction in Natural Gas
El Paso Natural Gas Co. [1]	5,530,679	10,235	-	0.94
Transcontinental Gas Pipe Line Corp. [2]	3,089,882	9,225	95.69	1.24
Texas Gas Transmission LLC [3]	2,684,369	5,881	-	1.63
Natural Gas Pipeline Co. of America [4]	2,481,770	8,939	-	1.24
Tennessee Gas Pipeline Co. [5]	1,992,417	14,113	96.59	0.71
Gulf South Pipeline Co, LP [6]	1,686,673	6,565	95.98	1.71
CenterPoint Gas Transmission [7]	1,677,076	6,162	-	1.15
Texas Eastern Transmission LP [8]	1,658,462	9,314	96.08	1.24
Dominion Transmission [9]	1,407,196	3,452	95.33	0.79
Northern Natural Gas Co. [10]	1,181,019	15,028	93.40	0.80
Colorado Interstate Gas Co. [11]	1,130,675	4,200	-	1.41
Wyoming Interstate Co. [12]	1,056,221	849	-	1.33
Southern Natural Gas Co. [13]	1,021,891	7,563	-	1.16
Florida Gas Transmission Co. [14]	888,535	4,851	95.93	1.09
Northwest Pipeline GP [15]	844,609	3,861	95.45	0.64
Great Lakes Gas Transmission LP [16]	830,429	2,115	96.37	0.76
Gas Transmission Northwest Corp. [17]	822,930	1,356	96.38	0.72
Kern River Gas Transmission Co. [18]	804,667	1,680	96.79	0.64
Mole fraction in natural gas			95.8	1.12

[1] http://www.elpaso.com/postings/default.asp
[2] http://www.1line.williams.com/Transco/index.html
[3] https://www.gasquest.txgt.com/Frameset.aspx?url=%2FReports%2FMeasurement%2FGasQuality.aspx%3FNav%3DTrue
[4] http://www.elpaso.com/postings/default.asp
[5] http://www.elpaso.com/postings/default.asp
[6] http://customeractivities.gulfsouthpl.com/default.asp?MENU=INFOPOSTINGS
[7] http://pipelines.centerpointenergy.com/
[8] http://www.link.duke-energy.com/

[9] http://www.dom.com/about/gas-transmission/index.jsp
[10] http://www.northernnaturalgas.com/
[11] http://www.elpaso.com/postings/default.asp
[12] http://www.elpaso.com/postings/default.asp
[13] http://www.elpaso.com/postings/default.asp
[14] http://www.hottap.panhandleenergy.com/
[15] http://www.northwest.williams.com/NWP_Portal/
[16] http://www.glgt.com
[17] http://www.gastransmissionnw.com
[18] http://services.kernrivergas.com/portal/Desktop.aspx

Conclusions

Using composition data from the top transmission companies, EPA determined that, on average, the composition of pipeline quality natural gas is 95.8% methane and 1.12% carbon dioxide. Therefore, a default composition of the 95% methane and 1% carbon dioxide would adequately represent the pipeline quality natural gas and result in minor errors in reporting. If the reporter believes their gas composition is significantly different, as was observed in specific cases, there are provisions that allow reporters to use their own composition instead of the default values.

APPENDIX D

Proposed Pressure Groupings for Monitoring Emissions from the Well Venting for Liquids Unloading Emissions Source by Sub-Basin.

Subpart W of the greenhouse gas reporting rule requires onshore petroleum and natural gas production facilities to report emissions from well venting for liquids unloading measurements as defined in 40 CFR 98.232 thru 98.238. In this action, EPA is proposing to replace the EIA field designation, referred to as the EIA Oil and Gas Field Code Master List or "FCML" in this document, with the "sub-basin" designation for sampling. EPA anticipates that the same quality of emissions data resulting from the "field" designation would be maintained with the "sub-basin" designation. With the sub-basin designation, EPA is proposing to include a further designation for which the reporter would take measurements within a sub-basin based on a combination of wellhead pressure group and unique tubing grouping as applicable. This appendix describes how EPA developed the wellhead pressure groupings.

Background

The Subpart W final rule requires a measurement to be taken from one well per liquids unloading event for each unique tubing diameter and producing horizon/formation combination in an estimated 18,500 gas producing fields. The emissions measurement from this sample is to be then applied to all unloading events of a similar tubing diameter, producing horizon/formation combination in each field using the FCML as applicable.

EPA received several requests to reconsider the provision in the final rule which requires reporters to take field-level measurements using the FCML. Commenters argued against using the FCML and asserted that the FCML did not address new fields and that the list changed significantly from year-to-year , and as a result reporters should not be required to us the FCML for measurement and sampling under the provisions in the final rule. EPA does not agree that the FCML is not an appropriate tool to use for sampling and measurement under subpart W, however, EPA has proposed an alternative sub-basin concept that will result in the same quality of emissions being reported. In EPAs discussions with these commenters, the commenters agreed conceptually that pressure was a factor in liquids unloading of the volume of gas vented, and that a sub-basin geographic delineation using counties to replace the EIA field code master list was acceptable.

EPA is proposing a county boundary delineation in place of the FCML delineation for determining a surface well classification in a sub-basin grouping. However, there are only 800 counties in the U.S. with gas producing wells, and each county may encompass many producing horizon/formation combinations with quite different production characteristics. Therefore to apply a single sample of one well liquid unloading event to all other similar events in a sub-basin (county), it is necessary to group those events by factors that most affect gas venting volume: namely gas well pressure and tubing diameter. EPA chose five pressure ranges, four bounded between zero and 200 psig at the wellhead and one unbounded range above 200 psig. Further, to be more definitive on "unique tubing diameter," EPA selected three nominal ranges of typical gas well tubing diameters. Therefore, for gas well liquids unloading, the operator is required to measure the natural gas flow rate of one liquids unloading event for each sub-basin, pressure range, and unique tubing diameter, instead of the provisions in the final rule which required measuring the natural gas flow rate of a liquids unloading event for *each* well tubing diameter and producing horizon/formation combination in *each* gas producing field.

This memo describes the analysis that was performed to optimize the pressure groups to a minimum potential error with one sample well applied to all other wells in each pressure group.
The bias or error in emissions reporting for the well liquids unloading source can be minimized by using a set of different pressure groups such that the sum of errors resulting from each pressure grouping is the lowest for the national emissions from this source. These pressure groups would enable reporters to estimate their emissions for all wells in a given group based on a one well sample in the pressure group.

Method

This analysis is based on five pressure groups to be consistent with, but lower burden than, the 2010 final rule. The reporter will still be able to measure the one liquid unloading event in each county-pressure range-tubing diameter range combination to apply to all other well unloading events in that same sub-basin category. The reporter will also still be able to estimate the emissions from every liquid unloading event using the equations in the rule that are a function of each well's geometry, shut-in pressure and number/duration of venting events per year. EPA has determined that the calculation of each well unloading will be less costly than the field measurement of one event in each sub-basin category, and therefore, this amendment adds no additional burden.

While the calculation of liquids unloading vent emissions in the rule, 40 CFR 98.233(f)(2), is based on reservoir shut-in pressure, this data is not reliably available in public literature, so just for this method of optimizing pressure ranges, the well flowing pressure data is used as a surrogate for shut-in pressure. The five pressure groups consist of four bounded groups between 0 and 200 psig, and one unbounded group above 200 psig. The analysis is designed to minimize the total error from the entire national population of conventional wells subject to liquids loading, assuming all wells are estimated by using the values from a representative gas well in each pressure group.

The first step was to estimate the emissions from a representative gas well. The estimate assumed an average gas well with a six inch casing and a depth of 6,000 feet. The estimate applied the Subpart W calculation methodology wherein the gas volume in the well casing at the average and maximum/minimum flowing pressure listed in the HPDI® database in the group would be blown to the atmosphere. The following equation was used to determine the volume of gas released from the well casing.

$$V_{Vent} = \frac{P_{Well}}{P_{atm}} \times \frac{\pi d^2}{4} \times L$$

Where:

V_{Vent} = Volume of vented gas, scf
P_{Well} = Pressure surrogate (i.e. flowing pressure) inside well casing, psia
P_{atm} = Atmospheric pressure, 14.7 psia
d = Diameter of well casing, taken to be 6 inches (0.5 ft)
L = Length of well casing, taken to be 6,000 ft

The next step involved scaling the emissions to all wells. This was done using data from the HPDI® database. All conventional gas wells were grouped by wellhead flowing pressure specified in HPDI® as a surrogate for shut-in pressure, in 5 psi increments. Any wells that had 0 psig shut-in pressure or wells without listed pressures were excluded from the optimization calculation. All wells with greater than 200 psig were grouped in the unbounded pressure group, and not included in the optimization calculation, because they were assumed to have adequate flowing pressure so as to not require liquids unloading to the atmosphere. Marginal wells, i.e. gas wells in highly depleted, low pressure reservoirs, were also taken into consideration. The Department of Energy classified wells that produce less than 60,000 scfd as a marginal wells. Based on that classification of marginal wells, it was determined that only 2% of marginal wells would be required to report under Subpart W. Therefore, for simplicity in this optimization of pressure ranges, all of the marginal wells in the HPDI® data were placed in the lowest pressure group for the analysis.

Total error was defined as total emissions at the maximum for each pressure group minus the total emissions at the average pressure for each group. This is shown in the following equation.

$$Error = \frac{\sum EM_{\max} - \sum EM_{avg}}{\sum EM_{avg}} \times 100\%$$

Where:

Error	=	Total industry error, %
ΣEM_{max}	=	Sum of emissions at the maximum of each pressure group, scf
ΣEM_{avg}	=	Sum of emissions at the average of each pressure group, scf

The total error was minimized by allowing the Microsoft Excel Solver function to allocate a portion of wells to each pressure group, until the optimum allocation was reached.

Results

From the analysis, five optimal pressure groups were chosen. The five groups were, in psig, 0-25, 25-60, 60-110, 110-200, 200+. From these pressure groups, excluding 200+ psig wells on the basis that all wells above that pressure would not require liquids unloading to the atmosphere, the total error was determined to be 29.82%. The results are summarized in the table below.

Table 1: Summary of Pressure Group Analysis

	Pressure Groups (psig)			**Number of Wells**	**Emissions (MMscf)**	
	Low	***High***	***Average***		***Average***	***High***
1	0	25	13	24,254	52.9	77.2
2	25	60	43	22,851	104.8	136.8
3	60	110	85	14,692	117.4	146.8
4	110	200	155	8,398	114.2	144.5
			Totals:	**70,195**	**389.2**	**505.3**
			Error:		**29.82%**	

Summary

For the number of wells potentially requiring liquids unloading in each of the four pressure ranges specified above, the deviation in emissions at the lower and upper bound relative to the average pressure in the range, for all ranges, is ±30%. It is assumed that the large majority of wells with flowing pressure above 200 psig will have sufficient reservoir energy to either not require liquids unloading at all, or are suitable for operation of a closed plunger lift system that does not vent gas to the atmosphere. As this number of measurement data points for county sub-basins, five pressure ranges and three tubing diameter ranges, is likely fewer than the final Subpart W rule, should reporters choose measurement over calculation, the burden would still be lower. However, given that the calculation methodology can be performed for all wells with readily available data on each well, and without any field data other than number and duration of well venting for liquids unloading, EPA still believes that that method is lower cost and so this amendment of the rule adds no additional cost burden. For further information please see the "Sub-basin Entity Pressure Range Analysis" document and the Sub-basin Entity By US County document in the docket: EPA-HQ-OAR-2011-0512.

APPENDIX E

Impact on Emissions Coverage Resulting from Proposed Amendments

EPA has proposed several amendments to provisions outlined in 40 CFR part 98 Subpart W. A subset of those amendments to provisions may have an impact on the emissions coverage under subpart W. Those amendments are as follows: 1) providing an equipment threshold for internal combustion equipment in onshore production; 2) providing a threshold for leak detection at transmission-distribution transfer stations; and 3) clarifying separate reporting of vented versus flared emissions. This appendix describes the potential impact of the proposed amendments on the emissions coverage for subpart W.

Equipment Threshold for Internal Combustion Engines

For both the onshore petroleum and natural gas industry segment and the natural gas distribution industry segment, external fuel combustion emissions from portable or stationary equipment with a rated heat capacity less than or equal to 5 MMBtu/hr only activity data are required to be reported. This 5 MMBtu threshold was developed based on significant data provided in comments to the 2010 subpart W proposal (75 FR 18608). Based on the information submitted (Please see Docket EPA-HQ-2009-0923 *Equipment Threshold for Small Combustion Units* for further background on data submitted), it was estimated that anywhere from 10s to 100s of thousands of small, external combustion devices such as line heaters, separator heaters, tank heaters, freeze protection heaters, which do not have fuel gas meters and, by nature of their automatic temperature controls, do not have records of on/off operating factors are below the 5 MMBtu threshold for rated heat capacity. EPA concluded that it was sufficient to require only the reporting of activity data for external combustion equipment below the threshold.

Shortly after finalizing subpart W and publication in the *Federal Register* (75 FR 74458), EPA received petitions for reconsideration on various provisions in the final rule, including the provision requiring reporting of greenhouse gas emissions from internal combustion engines. In specific, industry requested reconsideration of a threshold for very small internal combustion sources, such as temporary, portable electrical generators, air compressors, welding machines and lighting generators used briefly at wellheads for construction and maintenance. From data available in onshore production permitting, EPA determined that a 5 MMBtu/hr threshold for internal combustion equivalent to the 5MMBtu/hr threshold for external combustion devices would exempt virtually all wellhead compressor and pump engines from onshore production reporting. EPA researched the available sizes of portable electric generators used for wellhead maintenance or small construction work (i.e. not well drilling and workover rigs or hydraulic fracture pumps) and found that virtually all are well under 1 MMBtu/hr. This source, portable generators for wellhead maintenance or small construction, was not included in the threshold analysis to the final rule because EPA had no activity data on this source, so exempting it from reporting does not significantly affect the coverage of Subpart W and avoids a burden of gathering considerable data from contractors. Further, EPA evaluated wellhead compressors that use natural gas, as these sources are also below 5 MMBtu, however, EPA did not propose an equipment threshold for wellhead compressors that use natural gas, because that is the bulk of combustion emissions from onshore production and there are no reliable estimates for this number The estimate of natural gas consumption provided by EIA is not of sufficient quality and EPA seeks this information to sufficiently understand natural gas consumption at production operations. Hence, the Agency currently lacks sufficient data on this source of emissions and believes that source may be a major contributor to the emissions from the onshore production industry segment. Subpart W is requiring reporting of activity data for external combustion devices below the 5 MMBtu/hr threshold, because these are typically stationary or long term positioned portable units. However, the 1 MMBtu/hr exemption does not require reporting activity data, because these units are virtually all portable and onsite for brief periods.

Conclusion
EPA concludes that adding this internal combustion threshold will change coverage only marginally, because maintenance related equipment are not expected to have significant emissions. But this change will reduce cost burden of collecting and reporting contractor emissions from relatively small, portable engines used briefly on well pads for maintenance and small construction.

Threshold for Exempting Leak Detection at Transmission-Distribution Transfer Stations
Subpart W of the Greenhouse Gas Reporting Rule requires reporting of emissions from natural gas distribution facilities, including the reporting of emissions detected using leak detection methods and emissions estimated using population emission factors. For the natural gas distribution industry segment, facilities were required to perform leak detection at transmission-distribution transfer facilities where gas is transferred from a transmission pipeline into a distribution pipeline.

In this proposal, EPA proposed several revisions to terms used in the final rule to further clarify EPA's intent of who would be covered under the rule. The term "custody transfer" has been replaced with "transmission-distribution transfer station." In addition, EPA has proposed to universally use the term "metering-regulating station" throughout the rule, and to clarify that TD transfer stations are a subset of those metering-regulating stations.

The proposed rule requires leak detection at both above and below grade metering-regulating stations, where gas moves from a transmission pipeline into a distribution pipeline. EPA understands that these TD transfer stations come in many sizes and configurations, including some very small stations with, perhaps, a single meter run, with and without pressure regulation. EPA also understands that there are many above grade meter-regulator stations that are not at gas transfer points between transmission and distribution, and are not customer meters, sometimes referred to as district regulators. For these stations, Subpart W requires the application of a population leak factor developed uniquely by each company from the leak surveys performed on the TD transfer stations. Therefore, all above grade metering-regulating stations are accounted for in the final rule. In consideration of industry's comment that performing leak surveys on some very small, remote, aboveground metering-regulating stations that transfer gas from transmission pipelines to distribution pipelines are burdensome and unwarranted by the improvement in emissions estimation, EPA is considering an appropriate threshold for such small, remote stations. Such a threshold would not exclude these TD transfer stations below any threshold from reporting emissions, but rather put them in the same class as the metering-regulating stations (i.e. applying the population leak factor developed from the company's leak surveys). Therefore, providing a threshold would not change the coverage. However, this could lower the quality of data being reported because a small TD station does always equate to a low magnitude of emissions. Emissions from a TD station are dependent mainly on factors such as maintenance practices and pressure drop across the regulator.

In conclusion, EPA does not anticipate that the emissions coverage will be greatly impacted by providing a threshold for leak detection at TD transfer stations; however, the quality of the emissions may be less because the emission factor may not accurately portray the emissions from a particular station..

Separate reporting of vented versus flared emissions

EPA has clarified in this proposal that vented emissions from each source should be reported separately from flared emissions. Although this has always been EPA's intent, the data reporting section did not clearly state this requirement for all sources; while some sources in the final rule clearly state this requirement. This clarification to the data reporting requirement is not expected to change emissions coverage because the monitoring methods are not impacted by the change. Furthermore, this will improve the data quality being received as vented emissions will clearly be reported separately from flared emissions.