Frequently Asked Questions

Subpart W: Petroleum and Natural Gas Production

United States Environmental Protection Agency

Offshore Petroleum and Natural Gas Production

Question: **Please clarify whether the final rule amending 40 CFR Part 98 applies to both onshore and offshore.**

Response: On November 8, 2010, EPA signed 40 CFR part 98, subpart W; a rule that finalizes reporting requirements for the petroleum and natural gas industry. This final rule covers both offshore and onshore petroleum and natural gas production facilities. Please review section 98.230 for the definition of the source category for each segment of the petroleum and natural gas industry covered by subpart. Information and resources regarding the applicability and requirements of subpart W are available at: http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **According to § 98.238, offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.**

*** What is terrestrial border?**

*** In south Louisiana most sites are located within the State boundaries in lakes, bays, and bayous (not in Federal waters). These waters are subject to the ebb and flow of the tide. In some cases these sites are 150 miles north of the Gulf of Mexico. The sites are over water on platforms built on pilings. Are these sites considered offshore or onshore sites?**

Response: The definition for offshore in § 98.238 includes "lakes or other normally standing waters", therefore, sites located in lakes, bays, etc are considered offshore.

Question: **Is it correct to conclude that emissions from stationary sources of fuel combustion are to be quantified and reported in accordance with the methodologies specified in 40 CFR Part 98 Subpart C and not as described in BOEMRE's GOADS instructions?**

Response:
EPA confirms that stationary sources of fuel combustion, except flares, must be reported using methodologies specified in 40 CFR Part 98 Subpart C; flare emissions have to be reported under subpart W, consistent with BOEMRE (30 CFR 250.302 through 304).

Question: **Offshore petroleum and natural gas production facility reported in the GOADS 2008 report, GHG emissions were <25,000 metric tons CO_2e from equipment leaks, vented emissions and flare emissions based on GOADS calculation methodology AND stationary**

combustion sources (i.e., sum of all GHG CO_2e - Subpart W and Subpart C sources). Assume that actual 2011 GHG emissions were >25,000 metric tons of CO_2e (Subpart W - GOADS method and Subpart C sources) for the facility.

a. Does this facility have to report GHG emissions for 2011 reporting year?

Response: If emissions in 2011 are 25,000 tons CO_2e or more for all sources covered by the greenhouse gas reporting rule, in this case sources under subparts C and W, then the facility must report. §98.233(s)(1)(i) also indicates that if the calendar year does not overlap with the most recent BOEMRE emissions study publication year, the reporter must use the most recent BOEMRE reported emission data and "adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study." Therefore, if reported 2008 emissions, adjusted for any differences in 2011 operating time, are 25,000 tons CO_2e or more, then the facility must report for calendar year 2011.

Question: **An offshore petroleum and natural gas production facility emits the following during 2011; note that the facility was NOT operating during 2008 and so no GOADS 2008 data available.**

a. 20,000 metric tons CO_2e from equipment leaks, vented emissions and flare emissions based on GOADS calculation methodology

b. 10,000 metric tons CO_2e from stationary combustion sources based on 40 CFR 98 Subpart C calculation methodology

c. Would this facility be required to report GHG emissions during 2011?

Response: Yes. The facility is identified as not being in GOADS in 2008, however, the total emissions from the facility is greater than 25,000 metric tons CO_2e. §98.233(s)(4) states that "for either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions". Also, 98.2(a)(2) (as referenced in 98.231(a)) states that "a facility that contains any source category that is listed in Table A-4 of this subpart that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories that are listed in Tables A-3 and Table A-4 of this subpart." Therefore, based on the information provided, this facility is required to report equipment leaks, vented emissions and flare emissions under subpart W and stationary combustion emissions under subpart C for calendar year 2011.

Question: **For offshore petroleum and natural gas production facilities under §98.233(s)(1)(i), the GHGRP states that these facilities shall report the same annual emissions as calculated and reported by BOEMRE and that any calendar year that overlaps with the most recent study publication year, the most recent BOEMRE reported emissions data should**

be used. We understand this to mean that for the 2011 reporting year, we can use 2011 BOEMRE data, rather that the previously available data from 2008. Please confirm that this is an acceptable approach.

Response: BOEMRE typically publishes a GOADS study after March 31 of the year following the data collection. Therefore, for Subpart W reporting year 2011, offshore reporters subject to BOEMRE must use the latest BOEMRE published emissions data (most likely 2008, as the 2011 GOADS report may not be available until after the March 31, 2012 reporting for subpart W). As a further clarification, the reporters will report under Subpart W for 2011 using the BOEMRE methodologies published in 30 CFR 250.302 through 304 with the latest BOEMRE emissions data. In subsequent years, reporters in state and non-Gulf of Mexico waters will report using the GOADS methodologies published in 30 CFR 250.302 through 304, which historically have been published along with the GOADS emissions data.

Question: **If an offshore oil & gas production platform/facility is farther out in the ocean than the limit of state waters (as defined by the Submerged Lands Act), does that facility have to report 2010 emissions data to EPA for Subpart C?**

Response: As provided in guidance during 2010 for offshore platforms, for the purposes of 2010 reporting for subpart C jurisdiction is based on the Submerged Lands Act of 2002 (43 U.S.C. §§1301-1315 (2002) and the Territorial Submerged Lands Act (48 U.S.C. 1705). Generally, their breadth depends on the state in whose jurisdiction the platform is located. Jurisdictions of Texas and the Gulf coast of Florida are extended 3 marine leagues seaward from the baseline from which the breadth of the territorial sea is measured, Louisiana's jurisdiction is extended 3 imperial nautical miles seaward from the baseline from which the breadth of the territorial sea is measured, other state's seaward limits are extended 3 geographic miles seaward from the baseline from which the breadth of the territorial sea is measured or to the international boundaries of the United States in the Great Lakes or any other body of water traversed by such boundaries. Please consult the State for information specific to the platform, and you may find helpful information at www.mms.gov/aboutmms/ocsdef.htm.

Please note that amendments were made in December 2010 (75 FR 74487) to extend applicability of the GHG Reporting Program to facilities “attached to or under the Outer Continental Shelf.” Those same rule amendments amended the definition of United States. Neither the amendments made to 40 CFR 98.2 (Who must report?) to include the Outer Continental Shelf, nor the amendments to 40 CFR 98.6 to clarify the definition of United States or add a definition for Outer Continental Shelf, were intended to have any impact on applicability under the GHG Reporting Program (GHGRP) for the 2010 reporting year for subpart C. The rule was made effective December 30, 2010 with the view that data collection would begin for subpart W January 1, 2011. We recognize that the changes to subpart A could be perceived to be applicable for the whole of 2010, however, this was not our intent. In fact, in other final rules published approximately the same time (75 FR 79095 and 75 FR 66436) we were very clear about how any amendments would apply to the current 2010 reporting year. In those rulemakings, we concluded that the amendments could be incorporated for the 2010 reporting year, because they, “primarily provide additional clarification regarding the existing

regulatory requirements, generally do not affect the type of information that must be collected and do not substantially affect how emissions are calculated". In specific cases where EPA concluded that the amendments impose additional substantive requirements not reasonably anticipated by reporters for the 2010 reporting year, we delayed implementation of the amendments to the 2011 reporting year.
EPA did not provide such a similar rationale for applying any of the amendments in 75 FR 74458 to the 2010 reporting year- the intent was for the amendments to take effect for the 2011 reporting year. Further, given that the amendments could affect applicability for offshore oil and natural gas facilities required to report under subpart C in 2010, it would not have been practical to make this change effective for the 2010 reporting year. Based on this, the guidance provided in earlier communications is still appropriate for the 2010 reporting year.

Question: **I need to know if facilities that fall under 40 CFR 98 Subpart W that are subject to report Stationary Fuel Combustion Sources must do so by March 30, 2011. Please provide the deadlines for reporting these sources for both Onshore and Offshore production.**

Response: Any facility, as defined in 98.6, with annual stationary fuel combustion emissions greater than or equal to 25,000 metric tons CO_2e in 2010 must report combustion emissions under subpart C by September 30, 2011.

For an onshore production facility, if annual combustion emissions were less than 25,000 metric tons CO_2e in 2010, but the facility is subject to Subpart W in 2011, then the facility must report all combustion emissions, equipment leaks, flared emissions, and vented emissions as required under W for 2011 from onshore on March 31, 2012. For offshore production facility, if annual combustion emissions were less than 25,000 metric tons CO_2e in 2010, but the facility is subject to Subpart W and C combined in 2011, then the facility must report all combustion emissions under Subpart C and all equipment leaks, flared, and vented emissions as required under W for 2011 from onshore on March 31, 2012.

Question: **Subpart W, via GOADS, requires monitoring of "hours operated" for "natural gas, diesel, and dual-fired turbines". I have two questions:**

1) Since emissions are calculated based on fuel use only, why is it necessary to monitor hours operated?

2) For dual-fired turbines, is it necessary to monitor hours operated on each fuel, or just the total?

Response: You must follow the methods in the rule. In response to industry comments regarding burden, EPA finalized requirements to use Bureau of Ocean Management, Regulation and Enforcement (BOEMRE) GOADS reporting methods for all offshore facilities under Subpart W. As GOADS is under BOEMRE jurisdiction, EPA has no authority regarding GOADS guidelines or methods.

Question: **I am working with a new off shore facility and my understanding is that they will start operations in early 2011. When they begin operations they would like to have their monitoring plan for the GHGRP fully in place. The plan they have right now only covers the combustion sources and they will need to include a component that addresses the monitoring requirements to comply with Subpart W.**

I was hoping you might have some insight regarding how new facilities that are subject to GOADS are supposed to report in 2012. They are supposed to use GOADS published data but for the new sources the data won't be ready in time for them to report in 2012. Should they be using the GOADS methodologies to calculate the emissions themselves?

Response: New facilities, whether or not under GOADS jurisdiction, have to follow 98.233(s)(4), which states, "For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions."

Therefore, if the facility is subject to the rule and is under BOEMRE jurisdiction but is a new facility that is not included in the most recently published GOADs report, then you must calculate calendar year 2011 emissions for equipment leaks, vent, and flare emission sources using the GOADS methodologies in the most recently published GOADS report.

Onshore Petroleum and Natural Gas Production

Question: **I currently have a client that has traditional oil and gas wells with various equipment including tanks, well heads, engines, compressors, dehydrators, separators etc. These wells are spread out over multiple counties. Do the regulations state how we should consider this situation in regards to determining whether I meet or exceed the GHG reporting threshold? Should we count each individual well site as a facility or count all the wells as basically one facility?**

Response: The facility definition for onshore petroleum and natural gas production is provided in section 98.238 of subpart W. Facility with respect to onshore petroleum and natural gas production for purposes of this subpart and for subpart A means all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility. Per this definition, all onshore production sources listed in 98.232(c) in the same basin are considered one facility.

Question: **In the "Leak Detection and leaker emission factor" subsection, I see that this section is not applicable to production. "You must...conduct leak detection of equipment leaks from all sources listed in Section 98.232 (d7), (e7), (f5), (g3), (h4), and (i1). Therefore, I wanted to clarify that leak detection is not applicable for wellheads, separators at well site, storage tanks and other equipment defined by "production equipment".**

Response: Onshore production reporters do not need to perform leak detection under §98.233(q) for equipment leaks. For an onshore petroleum and natural gas production facility, equipment leaks are calculated with the methodology in §98.233 (r), using population count and population emissions factors.

Question: **With respect to the onshore petroleum and natural gas production segment and the natural gas distribution segment, reporting of combustion emissions under subpart W is redundant for those facilities also subject to subpart C. Yet the necessary information seems different between Subpart W's subsection and Subpart C. The question is which subpart takes precedence in our monitoring methodology?**

Response: For both the onshore production and natural gas distribution industry segments, all combustion emissions monitoring and reporting requirements are incorporated into Subpart W. Hence, data reporting for the onshore production and natural gas distribution segments' combustion emissions starting in 2011(reported 2012) are reported under Subpart W. Please note that for year 2010 onshore production and natural gas distribution reporters have to comply with requirements of Subpart C for combustion emissions and, accordingly report combustion related emissions under subpart C in 2010.

Question: **Please provide additional definition for determining the limits of a "basin". The rule defines a basin as "all wells in a particular county". We have multiple isolated fields in the same county/parish, and some fields that are in multiple counties/parishes. Do we group all oil and gas wells in a geologically defined field, as the "basin", for applicability purposes?**

Response: The definition of both a basin and a facility, as applicable to onshore petroleum and natural gas production, is provided in 98.238.

Facility with respect to onshore petroleum and natural gas production for purposes of this subpart and for subpart A means all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10

(October 1991) (incorporated by reference, see § 98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see § 98.7).

Therefore, all oil and gas wells in a basin as defined by Subpart W have to be grouped together for applicability purposes.

Question: **I am trying to understand the definition of a "Facility" as it pertains to 40 CFR Part 98 - subpart W. The definition uses the word "Basin". I have copied text from both the rule and preamble below. Is this saying that all equipment associated with one or more production facilities, within the same parish (county), and owned by the same company, are considered one facility? The way it reads to me is that the parish (county) lines are being used to delineate the basin boundaries. Is this correct?**

Rule: Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Preamble: Basins are mapped to county boundaries only to give a surface manifestation to the underground geologic boundaries. EPA decided to use the AAPG geologic definition of basin because it is referenced to county boundaries and hence likely to be familiar to the industry, i.e., if the owner or operator knows in which county their well is located, then they know to which basin they belong.

Response: For the onshore petroleum and natural gas production industry segment, the facility is comprised of all wells in a single hydrocarbon basin that are under common ownership or control (see full definition in 98.238). Basin is defined in 98.238 also (see below). A basin is not a county. What the preamble was explaining is that the AAPG definition of basin was selected because it uses county boundaries rather than other descriptors (e.g., UTM coordinates) to define basins. A basin definition that is defined by county boundaries is easier for a reporter to understand because it uses known geographical demarcations as compared to ones that use other metrics. A basin can be comprised of multiple counties.

"Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see § 98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see § 98.7)."

This definition of facility for onshore production does not apply to the other 7 source categories in subpart W.

Question: **Are the blowdown emissions from a compressor, separator, or other field equipment included in the Onshore petroleum and natural gas production sector?**

Response: Blowdown emissions from field equipment in the onshore petroleum and natural gas production segment are not included for reporting under the onshore petroleum and natural gas production industry segment; see section 98.231(a) and 98.232(c).

Question: **Are the emissions factors listed in Table W-1A for both leaking components and non-leaking components? How do you calculate emissions from leaking components if onshore petroleum and natural gas source are not required to monitor components?**

Response: Equipment leak emissions in onshore production are to be estimated using methods provided in 98.233(r)(2). Hence, no leak detection of emissions is required for onshore production. Table W-1A provides population emission factors, which represent the emissions on an average from the entire population of components – both leaking and non-leaking; please see section 6(d) of the Technical Support Document for further details on the concept of population emission factors.

Question: **98.233(j) – Onshore production storage tanks. The regulation stipulates that calculation methodologies for onshore production storage tanks depends on whether the separator has a throughput greater than or equal to 10 barrels per day. Our clients expect that this would be based on actual annual average since this is an annual report of actual emissions. Please confirm.**

Response: The 10 barrels per day of oil throughput referenced in 98.233(j) is based on annual average daily throughput.

Question: **How should the daily oil throughput be determined for onshore production storage tanks in 98.233(j) to compare to the threshold of 10 barrels/day? Is it based on design capacity, maximum daily throughput, or annual average actual daily throughput? Is the throughput re-evaluated annually? If the throughput decreases below this threshold, are the equipment excluded from report under Subpart W?**

Response: It is EPA's intent that the 10 barrels per day of oil throughput referenced in 98.233(j) be based on annual average daily throughput. On an annual basis, the owner/operator must evaluate whether individual well pad produced hydrocarbon liquids falls above or below the equipment threshold and use monitoring methods appropriately. For less than 10 barrels per day of oil throughput, the reporter must determine if 98.233(j)(5) applies.

Question: **For an onshore petroleum and natural gas production site, I am confused on which calculation to use for centrifugal compressor venting 98.233(o). Should the facility use 98.233(o)(1)-(7), and therefore use equations W-22, W-23, W-24 and W-25? The calculations are contradictory and redundant.**

But maybe the facility should only calculate emissions for wet seal oil degassing vents (as suggested in the checklist). Therefore should the facility only use 98.233(o)(7), and therefore use only equation W-25?

Response: Onshore petroleum and natural gas production facilities should refer to §98.233(o)(7) to calculate emissions from centrifugal compressor venting.

Question: **Does EPA have the hydrocarbon basin map they reference in 98.238 available on their website some place? Please provide me with the link. I've tried tracking it down with the American Association of Petroleum Geologists but have not had any luck.**

Response: No, the hydrocarbon basin map is not on the EPA website. The AAPG Geologic Province map can be found at: The American Association of Petroleum Geologists (AAPG) Bulletin, Volume 75, No. 10 (October 1991) pages 1644-1651. http://www.aapg.org/eseries/scriptcontent/BeWeb/orders/ProductDetail.cfm?pc=DD0021

Question: **For combustion equipment that triggered Subpart C reporting, can this be incorporated into Subpart W reporting for CY2011, or will there be 2 separate (Subpart C and Subpart W) reporting schema?**

Response: Onshore petroleum and natural gas production facilities and natural gas distribution facilities must report stationary and portable combustion emissions as specified in §98.233(z). For all other source categories in Subpart W, emissions from each stationary fuel combustion unit must be reported under subpart C.

Onshore Natural Gas Processing

Question: **Section 98.230(a)(3)(ii) states that "All processing facilities that do not fractionate with throughput of 25 MMscfd per day or greater." are included in the source category. Please specify the basis for the 25 MMscf per day throughput - is this based on annual average daily flow or max design capacity?**

Response: The gas processing plant throughput threshold in 98.230(a)(3)(ii) is based on annual average throughput.

Question: **Regarding terms "fractionate" and "fractionation" in 98.230(a)(3): Please define; does this refer to separation of NGLs from methane, or the separation of NGLs into chemical species or commercial products?**

Response: It is EPA's intention for the purpose of Subpart W to follow general industry parlance whereby "fractionate" and "fractionation" refers to the separation of NGLs into individual chemical species or commercial products.

Question: Section 98.230(a)(3) states that the onshore natural gas processing industry segment includes (i) all processing facilities that fractionate and (ii) all processing facilities that do not fractionate with throughput of 25 MMSCF per day or greater. Does this mean that onshore natural gas processing facilities that do not fractionate and which have a throughput of less than 25 MMSCF per day are not subject to GHG reporting requirements?

Response: As per the definition provided in 98.230 (a)(3), onshore natural gas processing includes "all processing facilities that do not fractionate with throughput of 25 MMscf per day or greater." Therefore natural gas processing facilities that do not fractionate and have a throughput less than 25 MMscf per day are not subject to the requirements of Subpart W. You may still be subject to other subparts of the rule (e.g., subpart C, General Stationary Combustion) therefore you should determine if you are applicable under any other subparts in 98.2(a).

Question: Under onshore natural gas processing where would you report vent emissions? We have a membrane plant (sweet gas so not acid gas removal) where we remove CO_2 and vent should this be reported under flare as unlit?

Response: If a membrane unit is used to remove CO_2 from natural gas, then emissions must be calculated and reported as specified in 98.233 (d). Please see EPA-HQ-OAR-2009-0923-1298-18 in the RTC for further details on the definitions of sweet and sour gas.

Question: In 98.230(a)(3)(ii), is 25 mmscf/day the design capacity for a processing plant or the actual capacity?

Response: The gas processing plant throughput threshold in 98.230(a)(3)(ii) is based on annual average throughput.

Question: If there is a natural gas processing plant located at the same location as an underground storage facility and they share compression, how should we report - as two separate facilities with estimated compression dedicated to each or as one combined facility. If we are one combined facility, should we follow the reporting requirements for a gas processing plant, an underground storage facility or both?

Response: If the natural gas processing plant and the underground storage operations are part of the same facility, as defined in 98.6 you would report as one facility and submit one annual GHG report for these operations. EPA has provided guidance on how reporters should report for co-located industry segments and dual purpose equipment, please see the comment response number EPA-HQ-OAR-2009-0923-1024-14.

Question: If fuel gas lines are not owned or operated by a gas processing facility, but are on the gas processing facility property, do the fuel gas lines need to be monitored for equipment leaks? We assume not because the processing facility has no control over these pipelines owned by a third party.

Response: The definition of facility in 98.6 requires equipment to be under "common ownership or common control." Therefore, based on the information provided, the fuel gas lines are not subject to the rule because they are not owned and/or operated by the reporting gas processing facility's owners/operators.

Question: **A facility receives a gaseous stream consisting of a high concentration of CO_2 for processing. The composition of the inlet gaseous stream is such that the methane composition is less than 70% by volume, and the gas has a heating value of less than 910 Btu per standard cubic foot. 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." EPA proposed a new definition of "natural gas" on August 11, 2010 to read, "natural gas is composed of at least 70 percent methane by volume or has a high heat value between 910 and 1150 Btu per standard cubic foot." Please confirm that a facility which processes an inlet gas stream with a methane content of less than 70% by volume, and a heating value of less than 910 Btu per standard cubic foot is excluded from the Onshore Natural Gas Processing segment.**

Response: The definition of "natural gas" in the final rule revision (December 17, 2010) excludes the composition and heat value specification and simply states: "Natural gas is a natural occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface of which the principal constituent is methane. Natural gas may be field quality or pipeline quality." Based upon the finalized definition of "natural gas", a facility that processes an inlet gas stream which is field gas could be included in the Onshore Natural Gas Processing segment if the process otherwise meets the definition of Onshore Natural Gas Processing.

Question: **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.**

Response: EPA has reviewed your question and is unable to respond at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future. http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **As I interpret Subpart W, gas processing facilities that do not process more than 25 mmScf/day are not subject to reporting under Subpart W regardless of whether they are subject to reporting under Subpart C. Can you please provide more guidance on how this threshold should be calculated? Is it an average daily throughput based on the entire reporting year?**

Response: The Rule states in §98.230(a)(3)(i) and (ii) that the onshore natural gas processing industry includes all facilities that fractionate, as well as all facilities that do not fractionate that have a throughput of 25 MMscf per day or greater. Only those non-fractionating facilities with a throughput of less than 25 MMscf per day would not be subject to reporting under subpart W even if the reporting threshold is triggered in Subpart C.

The gas processing plant throughput threshold in 98.230(a)(3)(ii) is based on annual average throughput.

Question: **Is the 25 MMscfd threshold that has been added for gas processing facilities 98.230(a)(3) based on design capacity, maximum daily throughput, or annual average actual daily throughput? Is the throughput re-evaluated annually? If the throughput decreases below this threshold, does the facility no longer need to report under Subpart W?**

Response: The gas processing plant throughput threshold in 98.230(a)(3)(ii) is based on annual average throughput. This throughput is re-evaluated annually. Once you are subject to the rule (e.g., your facility contains a source category listed in Table A-4), your facility must continue complying with all the requirements of this part, even if the facility does not meet the applicability requirements in a future year (i.e., 25,000 mtCO_2e for petroleum and natural gas systems). The definition of the source category for petroleum and natural gas systems, under onshore natural gas processing, refers to a processing facility that does not fractionate and has a throughput of 25MMscf per day or greater. Because a gas processing facility that is over 25 MMscf per day meets the definition of the source category for subpart W, any facility that becomes subject to the rule in whole or in part because of a natural gas processing facility, would have to continue reporting until it meets the conditions for cessation of reporting in 98.2(i).

However, please note that if, in year 2, your throughput capacity is less than 25 MMscf per day, you are not required to calculate and report GHG emissions from gas processing in year 2. You would still be required to report other covered emissions at your facility. This is because gas processing would not be an applicable segment for year 2. Nevertheless, your facility would still be required to report in year 2, even if facility-wide emissions are less than 25,000mtCO_2e, and would continue to report until you meet the criteria in 98.2(i) for ceasing to report.

Question: **Which takes precedence for determining the Subpart W applicability of a natural gas processing facility- the 25,000 MT CO_2e threshold [under 98.2(a)(2)] or the 25 MMscf per day throughput [under 98.230(a)(3)]?**

For example, if a processing facility has less than 25,000 MT CO2e in combined emissions from stationary combustion, flaring, vented, and fugitive BUT the throughput of the facility is 30 MMscf per day, is the processing facility still obligated to report under Subpart W?

Response: Both the 25,000 metric ton CO2e threshold (from §98.2(a)(2)) and the 25 MMscf per day throughput capacity (from §98.230(a)(3)(ii)) are considered when determining subpart W applicability for a natural gas processing facility.

Since the throughput of the facility was identified in the question as 30 MMscf per day throughput capacity, this exceeds the exclusion identified in the §98.230(a)(3)(ii) for processing facilities that do not fractionate. Therefore, this facility falls under the onshore natural gas processing industry segment definition as defined in §98.230(a)(3) and these emissions would be included in the applicability determination for your facility. (If the throughput were less than 25MMscf this source would not have been considered in the applicability determination for the facility.) However, based on the information provided, since the processing facility has less than 25,000 metric tons CO2e in combined emissions from stationary combustion, flaring, vented, and fugitive sources, the facility does not need to report under subpart W.

Question: 98.233(n)(2)(ii) indicates that if a gas processing plant does not have a continuous gas composition analyzer, the composition of the flared stream depends on whether the gas flared is upstream of the demethanizer, downstream of the demethanizer, or is a hydrocarbon product. However, at gas processing facilities, flared gas can be a combination of gases before and after the demethanizer as well as hydrocarbon product. In addition, for certain facilities it is not possible to distinguish between the streams being flared. EPA has allowed the use of engineering calculations when flaring hydrocarbon products; since these products cannot be separated from the other streams being flared, please confirm that flare gas composition for use in Equations W-19 through W-21 can also be based on engineering calculations?

Response: EPA agrees that in the event that it is not possible to distinguish the source streams from the processing facility being flared, whether being located upstream or downstream of the demethanizer, or being a hydrocarbon product stream, reporters may use engineering calculations based on process knowledge and best available data.

Question: Section 98.230(a)(3) states that the onshore natural gas processing source category includes equipment that engages in liquid removal, and 98.232(d)(4) states that dehydrator vents in this source category are covered. But 98.230(a)(3) states that the source category does not include gathering lines or boosting stations. There is a lack of clarity as to whether any liquid removal that is located on a gathering line and that meets the thru-put thresholds is considered part of "processing" and subject to the reporting rules or whether it is excluded because it is on the gathering line. Specifically, this question relates to the following scenario: A dehydrator or a "knockout pot" is located on the gathering line after the wellhead and on the site of a booster station. The dehydrator or "knockout pot" removes liquid from the gas before it is compressed and then sent to the processing plant. This liquid removal is performed as a safety measure because liquid cannot be compressed and is therefore not considered a process. Does the onshore natural gas processing source category include the dehydrator or "knockout pot" in the above example?

Response: EPA has reviewed your question and is unable to respond at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future. http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **Under Subpart W, are we required to calculate potential GHG emissions from all compressors at a Natural Gas Processing facility? Some of our compressors are only used for refrigeration and use 100% propane; they do not use or process any GHGs. It seems that because they are not in service for natural gas processing that they would not be subject to the reporting requirements.**

Response: 98.232 (d) states that "for onshore natural gas processing, reporting CO2, CH4, and N2O emissions from the following sources." If the compressor stream is 100% propane then the emissions will not include CO2, CH4 and N2O emissions and therefore will not have to be reported under Subpart W. However, if the facility exceeds the 25,000 mtCO2e threshold then the owner or operator must report combustion emissions for this compressor under Subpart C.

Question: **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 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.

Response: EPA has reviewed your question and is unable to respond at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future.

http://www.epa.gov/climatechange/emissions/subpart/w.html

Onshore Natural Gas Transmission Compression

Question: Under section 98.233, for transmission storage tanks, the rule states to monitor the tank emissions for 5 minutes then use a meter to quantify the emissions. Under 98.234#1, the rule says any emissions detected by the camera is considered a leak. Is there a difference here? How do we treat intermittent emission from the storage tank? Can we use an alternative method to quantify the emissions? Or are we limited to the means listed?

Response: The purpose of this detection and measurement is to determine and quantify any continuous gas emissions from condensate storage tanks. The most common source of vapor emissions from a transmission compressor station condensate tank would be liquid transfer from compressor scrubber dump valves. These sources operating properly would be intermittent transfer of liquids from high pressure vessels to an atmospheric storage tank, with a short term flashing of dissolved gas, which is assumed to be less than 5 minutes in duration. Malfunction of scrubber dump valves can result in high pressure vapor leaking through the valve, into the condensate tank, and out the tank roof vent, which would vent indefinitely. This continuous release of vapor is detected as a continuous blow of gas from the condensate tank roof vent using a leak imaging camera or by using an acoustic through-valve leak detection instrument. Based on the current rule, the tank needs to be monitored to determine whether the “tank vapors are continuous for 5 minutes”; see section 98.233(k)(2). So if a leak is detected per requirements of 98.234(a)(1) and is continuous per the requirements of 98.233(k)(2) then the reporter has to measure the emissions per requirements in 98.233(k)(2)(i)-(iii). The reporter has the choice of using an acoustic leak detection device to detect and measure leaks per requirements in 98.234(a)(5). You cannot use alternative methods to those outlined in the rule.

Question: What is the definition of a "Booster Station"? One could assume that main transmission line compressor stations with or without gas treating equipment are booster stations and wouldn't have to report under Subpart W. Of course most of our mainline compressor stations crack the 25,000 tonne threshold on compression alone, so we would report under Subpart C. What is the exact definition of a booster station with regards to the

Transmission, Processing Sectors versus the Production Sector.

Response: EPA has reviewed your question and is unable to respond at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future. http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **For transmission tank venting sent to the flare, the reporter is referred to the emissions source for flare stack emissions, but guidance is only provided for upstream production and gas processing in this section.**

Response: If you have a gas analyzer installed, you must use it. If you do not, then consistent with 98.233(n)(2)(iii), you must use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

Question: **On the Transmission side, it appears only Condensate tanks at Facilities require leak checks (not other tanks at facility or not at facility)?**

Response: Yes, for the transmission industry segment, only condensate storage tanks (water or hydrocarbon) require leak checks. For further clarification, please see 98.232(e) and 98.233(k) of the rule.

Question: **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.**

Response: We are not able to provide further guidance at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future.
http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **I have a question on a natural gas compressor station that operates four 10.58 mmbtu/hr natural gas compressors for natural gas transmission and a 1,475 hp emergency generator with a 500 hour per year permit limit.**

Question:

Does the facility only need to calculate CO2 emissions (CO2, methane and N2O) for the natural gas combustion of the compressors to see if they exceed the 25,000 metric tons of CO2 threshold as required by Subpart A. Since they are a Subpart C source do they only need to calculate the emissions to see if they exceed the reporting threshold or do they need to test and check for leaks? If they are below the 25,000 metric tons I presume they do not need to report?

What about the emergency generator emissions?

Response: Pursuant to 40 CFR 98.2, if a facility's calculated total annual emissions are less than 25,000 metric tons of CO2e and the facility does not contain a source category listed in Table A-3 of 40 CFR part 98, subpart A, then the facility does not have to report under 40 CFR part 98 as a direct emitter.

For the purpose of determining the applicability of 40 CFR part 98 for the 2010 reporting year, the facility should calculate the emissions from the gas compressors pursuant to 40 CFR 98.30(a)(2). So long as a the emergency generators meet the definition of "emergency equipment" as stated in 98.6, emissions from the emergency generators are exempt and should not be calculated. If the facility is subject to 40 CFR part 98, you should report combustion emissions pursuant to the applicable requirements of subpart C (General Stationary Fuel Combustion Sources).

For the purpose of determining the applicability of 40 CFR part 98 for the 2011 reporting year, the facility should calculate the combustion emissions pursuant to 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) and equipment leak and vent emissions pursuant to 40 CFR part 98, subpart W (Petroleum and Natural Gas Systems). Transmission compressor stations follow subpart C for calculating combustion-related emissions and subpart C exempts emergency equipment. Based on the information provided, if the facility is subject to 40 CFR part 98, you should report combustion, equipment leak, and vent emissions pursuant to the applicable requirements of the subparts.

Information and resources regarding the applicability and requirements of the aforementioned subpart are available at:

http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **We would like further clarification on the applicability of 40 CFR 98 Subpart W for CO2 pipelines. The pipelines contain approximately 95% CO2, which currently does not fit the definition of residue gas as defined in 98.238 Residue Gas and Residue Gas Compression. In addition, the definition for Onshore Natural Gas Transmission Compression in 98.230(a)(4) specifies it "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." This definition includes "natural gas" but not CO2. Will CO2 pipelines be subject to the Onshore natural gas transmission compression segment under 40 CFR 98 Subpart W?**

Response: CO_2 pipelines are not required for reporting under Subpart W. See response to comment EPA-HQ-OAR-2009-0923-1024-19 for further details.

Underground Natural Gas Storage

Question: How do we report emissions from separate facilities that inject or withdraw gas from the same underground storage reservoir? These facilities may also fall under other industry segments (e.g. Transmission Compression or under Subpart C for general combustion sources).

Response: Underground storage and compression and transmission compression are two separate industry segments. A "facility", as defined in 40 CFR 98.6, must determine if it contains any of the industry segments listed in subpart W and compare its emissions from all applicable industry segments against the 25,000 $mtCO_2e$ threshold defined in 40 CFR 98.2(a)(2) to determine applicability. For a response to the question related to multipurpose facilities and dual purpose equipment, please see the response to EPA-HQOAR-2009-0923-1021-14. If multiple owners or operators use the same underground storage operation, one designated representative must be appointed for reporting purposes.

Question: Could EPA clarify that the natural gas stored in high pressure steel bottles at peak-shaving stations should NOT be considered an underground natural gas storage facility under Subpart W?

Response: High pressure steel bottles that store natural gas at peak-shaving stations without any subsurface storage per section 98.230(a)(5) would not be considered underground natural gas storage under Subpart W. However, if the high pressure steel bottles are located at underground storage per section 98.230(a)(5) then the equipment leak sources listed in 98.232(f)(5) would be subject to reporting.

Question: What is the definition of "facility" for Underground Storage? The "segment" definition in 98.230(a)(5) leaves us with several related questions.
a. Underground Storage Compression vs. Transmission Compression: Under Sec. 98.236(a) (p. 288), the rule requires us to report annual emissions separately for different industry segments. The definition of underground natural gas storage (Sec. 98.230(a)(5)) says "underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing; natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs."

Question: How do we report emissions from separate facilities that inject or withdraw gas from the same underground storage reservoir? These facilities may also fall under other

industry segments (e.g. Transmission Compression or under Subpart C for general combustion sources).

b. Equipment between Compression and the Wellhead: Does the definition of underground natural gas storage include the equipment between the storage facility (i.e. compression) and the wellhead e.g. meter runs, separators, and drips?
c. Filters and Separators: Are filters and separators located at the interconnect meter stations at storage headers considered part of the underground storage facility?

Response: A "facility", as defined in 40 CFR 98.6, must determine if it contains any of the industry segments listed in subpart W and compare its emissions against the 25,000 $mtCO_2e$ threshold defined in 40 CFR 98.2(a)(2) to determine applicability. Underground natural gas storage is as defined in 98.230(a)(5) and includes reporting of GHGs as listed in 98.232(f)(1) through (5). Therefore, the reporter needs to determine all applicable sources as per this industry segment definition and sources to report. Specifically, filters and separators are not listed as sources under 98.232(f)(1) through (5) but if filters or separators are associated with any sources under this section, reporting of those listed sources is still required.

The sources required to report are listed under the underground storage source category is listed in 98.232 (f). In this list dehydration units are not included therefore reporting from this source type is not required.

Question: **Underground Storage Owned and Operated by Different Companies: If company A owns and operates the underground storage facility (i.e. compression) but the associated storage wellheads are owned by company A and B, in equal percentages, but operated by Company B, is it possible to submit 2 separate emission reports by each respective operator?**

Response: Please refer to the definition of "facility" in 98.6. Based on the information provided, it would appear that company A would be required to submit one emissions report for the underground storage and the associated wellheads. Please refer to the response to comment EPA-HQ-OAR-2009-0923-1024-16 regarding reporting by designated representatives.

Question: **If onshore natural gas transmission has different emission factors for compressor and non compressor components, why don't natural gas storage facilities have the same? Some storage facilities can compress up to 3000psi! There is no provision for the different component categories for compressor or non compressor components!**

Response: EPA does not have sufficient data to support the differentiation of compressor and non-compressor components for underground storage. Should peer-reviewed data become available, at a time deemed appropriate by EPA, EPA would consider evaluating information on different emission factors for compressor and non compressor components for the underground natural gas storage industry segment under subpart W.

Question: **Re: Subpart W - Brine and diesel are used in the salt dome mining process to create an underground natural gas storage facility for storage or load balancing of natural gas. During solution mining of the salt dome to create the underground storage facility, methane may be emitted from the brine water storage tank (on a more or less continuous basis) or the diesel storage tank (when the tank is vented as pressure builds up). These liquids are used in the salt dome mining process prior to the introduction of natural gas when the underground storage facility is completed. Does Subpart W require reporting of these emissions? Or are emissions from underground natural gas storage facilities to be reported starting when natural gas is introduced for load balancing and/or storage?**

Response: Under 98.230(a)(5) reporting is only required for "…salt dome caverns that store natural gas…" Methane emissions from building of a storage facility are not included in the reporting for subpart W. Emissions reporting is required when the storage facility is operational.

Question: **Subpart W Table W-4 has four sections in the final Federal Register publication. The first and third sections are both labeled "Leaker Emission Factors Storage Station, Gas Service" and both tables have an entry for "Open-ended Line". It appears from the factor given that the first section is correct. In the proposed rule the "Storage wellheads" section has an "Open-ended Line" value which is now missing in the final rule. It appears that the storage wellhead factors table was split up and mis-labeled in the final rule.**

Response: EPA has acknowledged the error and is considering options to address this. The entry in Table W-4, the second occurrence of the emission factor for Open-Ended Line with a value of 0.03 scf/hour/component should be included in the Population Emission Factors – Storage Wellheads, Gas Service section of Table W-4.

Question: **I have a facility that will be constructed in 2011/2012 timeframe. It will be an underground natural gas storage facility with associated wellhead storage. In addition to injecting gas for storage, it will also inject gas for enhanced oil recovery (EOR). This means the storage station will also meet the definition of onshore natural gas processing and some of the wellheads will meet the definition of onshore petroleum and natural gas production. There will be no way to separate the storage activities from the EOR activities as most equipment is used for both.**

For underground storage the wellheads and storage station would be aggregated and reported as one entity. For onshore production and natural gas processing the onshore production would be reported as one entity and the onshore processing as another entity. To make matters more confusing, each industry segment has different sources to include for reporting. How do we deal with this under Subpart W. Do we call it underground storage and ignore the sources that would fall under onshore production or processing plant that are not included as applicable sources for underground storage? If we report under both we will be double counting multiple sources.

Response: What constitutes a facility, how to determine the reporting threshold, and reporting of emissions from collocated and dual purpose equipment is as follows:

1) As a first step the reporter must determine the emissions from all equipment listed in 98.232(c) for onshore petroleum and production. Per section 98.231(a) only sources listed in 98.232(c) need to be considered for threshold determination for onshore petroleum and natural gas production. 98.238 defines "facility" for the purposes of onshore petroleum and natural gas systems. Per the requirements of 98.3 each "facility" must submit a GHG report for all source categories at that "facility".

2) Note that while identifying onshore production emissions sources reporters have to determine whether the source is "on the well pad or associated with a well pad". The location of production wells within other facilities is inconsequential to this determination. Sources on a well pad or associated with a well pad across the entire reporting basin have to be taken into consideration. If your emissions from onshore petroleum and natural gas production are equal to or greater than 25,000mtCO2e, then onshore petroleum and natural gas production facilities report as a separate facility and include all emissions sources listed in 98.232(c).

3) Except for onshore petroleum and natural gas production and natural gas distribution, which have unique facility definitions, all other segments subject to subpart W are considered in the threshold determination for a single facility. You would also include emissions from other source categories at your facility (e.g., stationary combustion).
If there are emissions sources that are dual purpose then the rule requires this piece of equipment to be reported under the majority use industry segment based on guidance provided in EPA-HQ-OAR-2009-0923-1024-14.

4) For collocated industry segments, which cannot occur in the case of onshore petroleum and natural gas production and natural gas distribution due to the requirements in 98.231(a), EPA has provided guidance on emissions reporting in EPA-HQ-OAR-2009-0923-1024-14.

Based on the information provided, the facility cannot be reported as onshore production and natural gas processing combined (see point 1 above). For all the other segments, the report should use guidance in points 2-3 above to determine the segment under which the facility should be categorized.

Question: **Are dehydration units that are used to dehydrate natural gas extracted from underground storage included within the definition of underground natural gas storage facility? If so, would those dehydration units be considered part of the same underground storage facility if they are located on a different site that is not contiguous with the compression facilities or wellheads?**

Response: The sources required to report under the underground storage source category are listed in 98.232 (f). In this list dehydration units are not included therefore reporting from this source type is not required.

Liquified Natural Gas Storage and Import and Export Equipment

Question: For LNG facility equipment that is in Gas Service, is only the equipment listed in Table W-5 (Vapor Recovery Compressor) required to be reported if it is found to be leaking as defined in the rule.

Response: Vapor recovery compressors use a population emission factor, hence there is no leak detection required. Reporters have to count the number of vapor recovery compressors and use the population emission factor.

LNG facilities will not be surveying the valves, connectors, and other components that are in Gas Service under 98.233(q). At an LNG facility, a compressor that recovers vapor, but is designed so that it does not have reportable emissions of methane-containing gas, such as a flooded screw compressor, or one with seals purged with pressurized nitrogen, will not be reported, in accordance with the rule and the EPA's response in Response to Public Comments, EPA-HQ-OAR-2009-0923-1026-7, p. 46.

Question: Do I have to calculate emissions from operational LNG storage tank venting at LNG storage facilities or LNG import or export terminals? Also, the equipment listed to be surveyed for leaks does not include pressure relief valves, an emissions source listed for other facility types in 98.233(q). Am I required to report these emissions?

Response: Section 98.233(q)(6) and (7) states that emissions factors for "…valves, pump seals, connectors, and other" shall be used from the tables in the rule. A pressure relief valve is a valve and the relief vent stack would be in the "other" category, so both are included the leak detection survey and required to be reported.

Question: I am confused as to how offshore LNG would apply. Some offshore terminals are basically buoys out in the ocean where a ship connects, regasifies the LNG onboard and injects natural gas under pressure into the pipeline. The ships are hooked up to the buoys for about a week to 10 days at a time. Once they offload their cargo, they return to their home ports and are replaced at the buoy by another vessel. These vessels - for purposes of air and water permits - have been determined by EPA to be stationary sources while they are connected and offloading, but treated as vessels while under way. How are we to treat GHG reporting applicability here? There are other types of offshore terminals that have all their equipment on a fixed or floating processing station. Those ships would be treated like ships coming to a traditional land based terminal where they offload for half a day and leave.

Response: The LNG import and export terminal source category includes offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. The floating vessels described above, not the ships, are considered LNG import terminal facilities. Applicability would be determined by determining the estimated emissions and comparing against the threshold in 40 CFR 98.2(a)(2).

Question: Only LNG Storage vessels located above ground are considered part of "LNG Storage" under Subpart W. However, "above ground" is not defined. How should LNG Storage vessels that are partially above-ground and partially below-ground (with the majority below-ground) be treated under Subpart W? Is an LNG Storage vessel considered "above ground" if any portion of the vessel is above grade?

Response: LNG storage vessels are considered above ground if any portion of the vessel is above grade.

Question: At LNG Storage sites, how should pumps that are internal and submerged be treated? Should they be treated as Pump Seal components even though they are submerged?

Response: Submerged LNG pumps are not covered in subpart W as there are no emissions from this source.

Question: Fugitives: Is the correct methodology for a facility subject to 40 CFR 98, with equipment classified under 40 CFR 98.232(h)(4), to conduct a leak detection survey as stated in 98.233(q) and use 98.233(r) to estimate emissions from sources that were determined to be leaking in the leak detection survey? If this is not correct, please specify the correct methodology.

Response: For equipment in 98.232(h), other than vapor recovery compressors the reporter should use methods in 98.233(q). For vapor recovery compressors the reporter should use methods in 98.233(r).

Question: Are LNG Storage sites located adjacent to Subpart D facilities (e.g. Electric Generating Stations) under "common control" required to report emissions under the Subpart D "facility", or should the LDC report the emissions under Subpart W? Or should the combustion emissions be reported under the Subpart D "facility", with the fugitive emissions reported by the LDC under Subpart W? In short, which facility should report which emissions? This is not an issue for RY2010 because only Subpart D reporting is required, but it will be an issue starting in RY2011.

Response: Based on the information provided, the questioner would report as a single facility under 40 CFR 98. The single facility would be required to report emissions separately for Subparts C, D and W in the EPA electronic greenhouse gas reporting system (eGGRT). In regard to specific sources, Subpart W requires the reporting of process and emissions from any source listed in 98.232(g) sent to a flare from LNG storage facilities, as defined in 40 CFR 98.230, under Subpart W according to the calculation procedures outlined in 98.233. Additional applicable emissions are to be reported under subpart D according to the methods described in subpart D. Finally, stationary combustion emissions are to be reported under subpart C.

Question: **I have a question pertaining to Subpart W. In 98.232(q), the listing of equipment that must have leak detection conducted includes a reference to 98.232(h)(4), which does not exist. Please clarify what the correct paragraph in 98.232(h) should reference?**

Response: We presume you are referring to 98.233(q). 98.232 (h)(4) does exist and refers to "equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leaks"; therefore, it is applicable to 98.233 (q).

Question: **For an LNG import facility, there does not appear to be a category to report normal vent emissions from an LNG storage tank. The vent is metered to monitor methane emissions from boil-off. Please clarify.**

Response: Section 98.232 (h) does not include boil-off venting from LNG storage tanks as an emission source under LNG import and export terminals; therefore, boil-off venting emissions from LNG storage tanks are not required. However, if the LNG storage tank is blown down to the atmosphere then reporting is required under 98.233(i).

Natural Gas Distribution

Question: **Multiple Leak Surveys - Section 98.233(q)(1) regarding leak detection and leaker emission factors (bottom of p. 218 of pre-publication notice) provides: "You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year."**

The preamble indicates that you must do one leak detection survey per year, and you may do multiple leak surveys. The wording in the rule above indicates that you must select either one or multiple surveys. This sounds as though we are required to indicate in advance how many leak detection surveys will be conducted in the year which is onerous and doesn't make sense. We believe you meant that we must conduct at least one leak detection survey in a calendar year, and if we find a component that has a "leak" (e.g. as understood under Method 21) then at our option we may fix the leak – e.g. by tightening a fitting -- and then conduct another leak survey to confirm that the component is not leaking.

Response: For natural gas distribution, a facility, which is the collection of all distribution pipelines, metering stations, and regulating stations that are operated by an LDC, is required to do at least one facility wide leak detection survey per calendar year and has the option to conduct additional facility-wide leak detection surveys; if the facility selects this option, the additional facility-wide survey(s) must be completed during the same calendar year in order to account for fixing one or more leaks in the annual GHG report. If the facility chooses to fix one or more leaks and conduct another survey to determine that the component is not leaking, it must conduct a facility wide leak detection survey in order to account for fixing the leak(s) in the annual GHG report. As leaks are random in nature and while some leaks are fixed others are likely to occur. Therefore, a comprehensive survey is the only statistically relevant manner by which to establish facility-wide leak emissions rates and account for leaks repaired. Please see the response to comment EPA-HQ-OAR-2009-0923-1014-9 for further details.

It is very important to note that the requirement to conduct additional facility-wide leak detection surveys should a company wish to account for fixing a leak does not preclude in any way a company from repairing a leak. If a company chooses to conduct only one facility-wide leak detection survey in a calendar year but finds a leak during the survey, the company can and is encouraged to fix the leak. The leak detected though, as noted above, must be reported as a leaker for the entire calendar year should the company choose not to conduct a second survey.

Question: Sunset Non-Leaking City Gates: What happens if an LDC goes out to a custody transfer city gate station year after year and finds that it has no leaking components? Could EPA provide a sunset provision so that annual leak surveys would no longer be required?

Response: Equipment/ component leaks are random in nature and minimal leaks in one year do not guarantee similar leak levels in the future. There are no sunsetting provisions for individual emissions sources, only facilities. EPA has provided provisions that allow facilities to stop reporting under certain conditions and with prior notification to EPA. Please see 40 CFR 98.2(i)(1) – (i)(3). EPA addressed sunset provisions in general in the proposal to the 2009 Mandatory Reporting of Greenhouse Gases Rule (74 FR 16478).

Question: Population Counts: It appears that there may be inconsistencies in some factors used in the equations that Distribution facilities are directed to use on page 220 for population count emissions (EQ W-31) and the calculated facility emission factor (EQ W-32) on page 224. "Counts" as used in EQ W-31 is the total number of a type of source or component type. Does this mean that all components should be counted?

"Count" as used in EQ W-32 is total number of meter runs, which will likely be a much lower number than the number of a given component type in a meter run. EF as calculated here is supposed to be a facility emission factor. This should work if there is only one meter run at a facility (above grade M&R city gate).

EFs for EQ W-31 is defined on page 221 as the EF determined in EQ W-32.
We would appreciate clarification regarding how the population counts will work in the different formulas.

Response: For natural gas distribution, for below grade meters and regulators; mains; and services, these sources shall use the appropriate default population emission factors listed in Table W-7 of subpart W.

The term “Counts” required in Eq. W-31 is a generic term, signifying the total number (activity) of the type of emission source under consideration, at the facility. For natural gas distribution non-custody transfer city gate stations, the term “Counts” refers to the total number of meter runs, since that is the activity on which the emission factor for this sector is based on (see Table W-7 of subpart W).

The emission factor as defined in Eq. W-32 is intended for the sources of above grade meters and regulators at city gate stations not a custody transfer, since these sources use the total volumetric GHG emissions at standard conditions for all related equipment leak sources. First, the reporter is required to estimate emissions "for all equipment leaks sources calculated in paragraph (q)(8) of" section 98.233. Then Es,i as defined in Eq W-32 is the emissions from ALL sources at above ground custody transfer stations. This when divided by the total number of meter runs for these custody transfer stations as in Equation W-32 results in an emissions factor per meter that includes all the sources.

The emission factor for non-custody transfer city gate station comes ONLY from W-32. For all other emissions source the reporter must use emissions factors in the tables as appropriately defined for EFs for Equation W-31.

Question: **I 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.

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.

Response: EPA has acknowledged the error and is considering options to address this issue.

Question: **For a distribution company that has underground service lines that are made of an unknown material, is it appropriate to assume the most conservative worst-case population emission factor (unprotected steel at 0.19 scf/hr/number of services) for each of these service lines if available data, excluding a costly excavation of the service line, does not document the material type for the particular service line?**

Response: Where no information is available on the type of service pipeline material, the reporter may make the best judgment based on available information and use appropriate emissions factors. It is not appropriate to assume the worst-case population emission factor. The reporter should document this determination in the monitoring plan under 40 CFR 98.3(g).

Question: **Subpart W provides population factors in Table W-7 for cast iron mains, but not for cast iron services. If a distribution company owns cast iron services, is it appropriate to develop a cast-iron specific service lines emission factor by taking the company's average service line length (in miles) and multiplying this by the emission factor for cast iron distribution mains?**

Response: There is no emission factor for cast iron services in Table W-7, therefore you are not required to calculate emissions from cast iron services.

Question: **If an LDC has an external combustion device (e.g. M&R Station Heater) that is < 5 MMBtu/hr located adjacent to a Subpart D facility under "common control", is reporting of the combustion emissions from the device required? If such a source were located at a stand alone site, it clearly would be exempt from Subpart W reporting. However, if it is located at a site adjacent to a Subpart D Electric Generating Station under "common control", it appears that the small combustion source's emissions may need to be reported. This is not an issue for RY2010 because only Subpart D reporting is required, but it will be an issue starting in RY2011.**

Response: In the case of an external combustion device of less than 5 mmBtu located in an LDC facility adjacent to a subpart D facility the equipment would be subject to Subpart W requirements and therefore exempted. The reporter must follow all applicable activity data collection requirements under Subpart W.

Question: **I have read the definition of a facility under Subpart W and need further clarity. We are a municipally owned local distribution company, and are subject to Subpart W of the rule. PGW has distribution systems, meter stations, pipelines and 2 natural gas plants that store LNG. Do we report each natural gas plant as 1 facility and the distribution systems along with the meter stations and pipelines as another?**

Response: The general definition of a "facility" provided in §98.6 indicates "any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas." This definition applies to the two natural gas plants that store LNG; see section 98.230(a)(6). Whether these two natural gas plants are two separate facilities depends upon whether or not they are located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way.

The definition of "facility" for the natural gas distribution industry segment is provided in §98.238: "the collection of all distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system." As indicated, this definition applies to the distribution systems, meter stations, and pipelines. The LDC is a separate facility without overlap with other industry segments mentioned in 98.230; see section 98.231(a).

Question: **Customer Meters and Regulators – In an upcoming technical corrections rule, could you revise section 98.232(i)(1)-(3) to clarify that customer regulators are also excluded from the reporting requirements? This could be done by inserting "and regulators" so that the rule states that "Customer meters and regulators are excluded." See page 165 of prepublication notice. Could you confirm that this was your intent?**

Response: We did not intend to include reporting requirements for residential and commercial customer meters and associated regulator(s). Note, we did not intend to exclude all regulators from mandatory reporting but only those included with residential and commercial customer meters not covered in Subpart W.

Question: **This Subpart covers stationary combustion emissions sources for LDCs. For combustion of pipeline natural gas it refers you back to Subpart C for HHV, emissions factors, and calculation methodology. In Subpart C there are exemptions for emergency equipment. Does this exemption apply to the sources which are potentially covered by Subpart W? In other words, if an LDC operates an emergency generator, is that covered by Subpart W or is it exempt from reporting by the guidelines for stationary combustion equipment as outlined in Subpart C?**

Response: Combustion emissions from emergency equipment under natural gas distribution is exempt from reporting under Subpart W. LDCs report stationary and portable combustion equipment under Subpart W per methodologies in §98.233(z), which refers to the methodologies in Subpart C. Emergency equipment is defined in Subpart A as "any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations". Subpart C clearly states that "This source category [stationary fuel combustion sources] does not include emergency generators and emergency equipment."

Question: **If an LDC detects and voluntarily fixes a leak, Subpart W requires the LDC to complete a leak survey on all Above-Ground Custody Transfer M&R Stations to get credit for the fixed leak. This requirement imposes an unnecessary burden on companies who voluntarily limit emissions. Does EPA intend to limit the burden on LDCs that voluntary fix leaks (e.g. allow LDCs to take credit for leaks fixed within 30-days of the leak survey, without retesting all Above- Ground Custody Transfer M&R Stations, which would provide LDCs with an incentive to fix leaks in a timely manner)?**

Response: Please see rulemaking docket EPA-HQ-OAR-2009-0923 under "Understanding the Substance of the DOT Regulations and Comparing Them to the Subpart W Requirements". In addition, please see response to comment EPA-HQ-OAR-2009-0923-1026-8.

Question: Custody Transfer M&R Stations tend to handle a significantly higher volume of natural gas at higher pressures than Non-Custody Transfer M&R Stations. Using an emission factor without accounting for the volume and pressure differences at the M&R stations results in significant over reporting. Does EPA intend to allow for any correction factors for Non-Custody M&R Stations?

Response: The rule does not allow for the use of correction factors for non-custody M&R stations.

Question: Please explain whether detecting leaks through soap bubble testing is acceptable for natural gas distribution systems and compressor stations?

Response: Reporters may use soap bubble testing methods as specified in Method 21 (please see 98.234(a)(2)).

Question: Subpart W requests a log regarding venting. Does this include maintenance work (i.e., tie-ins, new mains, etc.), or is it assumed that this value is included with the emission factors?

Response: EPA is assuming that the question is related to the use of population emission factors to calculate the emissions from distribution mains and service lines. The emission factor in Table W-7 for distribution mains and distribution services does not include maintenance work on pipes. Emissions from maintenance work on pipe are not required to be reported; please see the response to comment EPA-HQ-OAR-2009-0923-1156-6. Therefore, a log of venting as a result of maintenance work is not required.

Question: For a 2011 report with the "Natural Gas Distribution" option selected; what definition does the term "stations" account for in the excel calculation spreadsheet?

Response: For the "Natural Gas Distribution" calculation utility, the term "stations" is defined by the explanation given in the source used for the methane emission factor (column F of the "Guidance & Sources" tab). Please see the following reference for more information:
GRI and EPA. *Methane Emissions from the Natural Gas Industry*. Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution. June 1996. pgs IV, 13-17 (Table 5-1), and 19-22. epa.gov/gasstar/tools/related.html

Question: What is the meaning of Substitute Data as it relates to Local Distribution Companies?

Response: The term "Substitute Data" is used in subpart W to refer to any data that is used to replace missing data. 98.235 states, "Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation."

Question: **Under 98.233(r), tubing systems that are equal or less than one half inch diameter are exempt from the requirements of paragraph (r) of Subpart W. For certain distribution companies, the ½-inch iron pipe size (IPS) pipe is a common standardized size used for gas service lines. Actual measurement shows these service lines to have an inside diameter of 0.66 inches. Is Subpart W referring to the standardized pipe naming convention when exempting one half inch diameter pipe? Or should tubing systems that are "½-inch" IPS be subject to paragraph (r) due to actual measured ID?**

Response: The term more commonly used today is nominal pipe size (NPS) not iron pipe size (IPS). The actual internal diameter (ID) depends not only on the outside diameter (OD) of the pipe but also the schedule (wall thickness) of the pipe which varies with the pressure rating of the pipe. Therefore the references to pipe size in the rule are to NPS not actual ID.

Other: Acid Gas Removal Units

Question: **98.236(c)(3) requires the "total throughput off the acid gas removal unit" to be reported. Please confirm that the throughput is the volume of gas exiting the AGR unit (outlet gas), not the volume of gas vented to atmosphere.**

Response: Yes, the term "throughput" refers to the volume of gas flowing out of the AGR unit.

Question: **This question relates to Subpart W, Acid Gas Removal Vents, using Calculation Methodology 3. Are we allowed to assume that volume fraction of CO_2 content in natural gas out of the AGR unit (Vo) is zero? This will result in a conservative estimate of AGR vent emissions.**

Response: No. §98.233(d)(8) does not instruct reporters to assume volume fraction of zero for V_0. Reporter must use the methodologies prescribed in §98.233(d)(8) to determine the CO_2 composition of the natural gas exiting the AGR unit (V_0).

Question: **Do acid gas removal units which are used to sweeten a liquid stream meet the definition of acid gas removal units (which states that units are used to sweeten a natural gas – i.e., gaseous – stream)?**

Response: The definition of acid gas removal unit in 98.238 states, "process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators." Reporters do not have to report data for acid gas removal units which are used to only sweeten a liquid stream.

Question: **This question relates to Subpart W, Acid Gas Removal Vents. Section 98.233(d)(11) states "Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility." If all of the emissions from an AGR unit are recovered and transferred outside of the facility, does the facility still need to calculate emissions pursuant to Section 98.233(d)(11) and then "reduce" the emission to zero?**

Also, if all of the emissions from an AGR units are recovered and injected underground (via an Acid Gas Injection Well), does the facility need to report zero emissions for the source under Subpart W? Or can the facility just report under Subparts PP and UU?

Response: EPA requires the reporters to calculate the emissions from AGR units and then adjust it downwards by the amount transferred outside of the facility. Therefore, if 100% of the CO_2 vented from an AGR unit is transferred outside of the facility, the CO_2 emissions from the AGR unit must be calculated prior to determining the amount being transferred outside the facility. Note that 98.236(c)(3) requires reporting of both the AGR emissions and emissions captured for offsite transfer separately, even if the numbers are the same.

As regards acid gas injection wells and subparts PP and UU, please see response to EPA-HQ-OAR-2009-0923-0582-31.

Question: 98.233(d)(11) – Acid gas removal vents. When calculating emissions from acid gas removal vents, the regulation reads, "determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated…downward by the magnitude of emission recovered and transferred outside the facility." Many operators perform on-site injection of acid gas – Our clients request that the EPA clarify that those performing on-site acid gas injection can also estimate their emissions downward.

Response: Reporters performing on-site injection of acid gas may not adjust emissions downward. 98.233(d)(11) clearly states that you may only adjust emissions estimates downwards for emissions recovered and transferred OUTSIDE the facility. Please see response to comment EPA-HQ-OAR-2009-0923-0582-31.

Question: **Do acid gas removal units which are used to sweeten a liquid stream meet the definition of acid gas removal units (which states that units are used to sweeten a natural gas – i.e., gaseous – stream)?**

Response: The definition of acid gas removal unit in 98.238 states, "process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators." Reporters do not have to report data for acid gas removal units which are used to only sweeten a liquid stream.

Question: **For AGR vents, Option 3, the MRR says a meter must be installed, but then says in the next sentence that engineering calculations may be used if a meter is not installed – this is unclear on whether or not a meter is required**

Response: The rule requires the use of a meter if one is in place. If a meter is not in place, the reporter has the choice of installing a meter or alternatively using engineering estimation; please see section 98.233(d)(5).

Question: **How are acid gas injection processes handled under Subpart W? Is this part of the traditional sources included for onshore production?**

Response: If the acid gas being injected is from a Subpart W reporting acid gas recovery unit then the reporter has to comply with section 98.236(c)(3)(iv) for data reporting.

Question: **I need some clarification. If there is an amine treatment system used to remove H2S from produced gas that is located at a boosting station is this subject to subpart W.**

The current subpart W source category also does not include reporting of emissions from gathering lines and boosting stations. However, gathering lines and boosting stations are not well defined and it is not clear if this would include amine treatment located at a boosting station.

Response: EPA has reviewed your question and is unable to respond at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future. http://www.epa.gov/climatechange/emissions/subpart/w.html.

Question: **98.233(d)(11) – Acid gas removal vents. When calculating emissions from acid gas removal vents, the regulation reads, "determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated…downward by the magnitude of emission recovered and transferred outside the facility." Many operators perform on-site injection of acid gas – we request that the EPA clarify that those performing on-site acid gas injection can also estimate their emissions downward.**

Response: Reporters performing on-site injection of acid gas may not adjust emissions downward. 98.233(d)(11) clearly states that you may only adjust emissions estimates downwards for emissions recovered and transferred OUTSIDE the facility. Please see response to comment EPA-HQ-OAR-2009-0923-0582-31

Question: **Do incinerators and/or thermal oxidizers need to be reported under Subpart W? The rule does not currently address either, only flares. In many cases, acid gas from an AGR unit is routed to an incinerator to burn. Though AGR units are required to report emissions under the rule, it would be inaccurate to report the AGR unit emissions without taking into account a downstream incinerator. If an incinerator is required to report under the rule, what calculation methods should be used, as there are not currently any calculation methods**

published?

Response: An incinerator and/or thermal oxidizer is considered a combustion unit. If an incinerator and/or thermal oxidizer is located within a production or distribution facility, you must follow 98.233(z) and report the resulting emissions under Subpart W. If an incinerator and/or thermal oxidizer is located within all other oil and gas segments, you must follow 98.33(a) and report under Subpart C.

Question: **In which units are we required to calculate and report emissions for Equation W-3? Can we use a flow meter to calculate annual emission CO2?**

Response: If the reporter uses the methodology set forth in 98.233 (d)(2), then a vent meter must be used to determine the annual volume of vent gas. The emissions calculated in Equation W-3 are in units of cubic feet per year. However, paragraph 98.233 (d)(10) references 98.233 (v) of this section, which converts the results from Equation W-3 into metric tons CO2e. You must report emissions in metric tons of CO2, by gas, as required to meet the reporting requirements in 98.3(c)(4)(iii).

Question: **Section 98.233(d)(11) states "Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility." If all of the emissions from an AGR unit are recovered and transferred outside of the facility, does the facility still need to calculate emissions pursuant to Section 98.233(d)(11) and then "reduce" the emission to zero?**

Also, if all of the emissions from an AGR units are recovered and injected underground (via an Acid Gas Injection Well), does the facility need to report zero emissions for the source under Subpart W? Or can the facility just report under Subparts PP and UU?

Response: EPA requires reporters to calculate emissions from AGR units and then adjust it downwards by the amount transferred outside of the facility. Therefore, if 100% of the CO2 vented from an AGR unit is transferred outside of the facility, the CO2 emissions from the AGR unit must be calculated prior to determining the amount being transferred outside the facility. Note that 98.236(c)(3) requires reporting of both the AGR emissions and emissions captured for offsite transfer separately, even if the numbers are the same.

As regards acid gas injection wells and subparts PP and UU, please see response to EPA-HQ-OAR-2009-0923-0582-31.

Other: Blowdown Vent Stacks

Question: **Clarify whether 98.233(i) Blowdown vent stacks is applicable to pipeline blowdowns (if occurring at a Subpart W "facility" such as a well pad). The term 'equipment' makes this unclear whether it only applies to compressors and tanks and their associated piping, or if it actually applies to pipeline blowdowns as well.**

Response: The blowdown vent stacks source is not listed under 98.232(c) and therefore does not have to be monitored for onshore petroleum and natural gas production.

Question: The calculation methodology for blowdown vent stacks indicates that natural gas volumetric emissions at standard conditions (calculated using Eq. W-14) are to be converted to GHG mass emissions using the methodology in 98.233(v). Unless the blowdown stream was a pure CH_4 or CO_2 stream, natural gas volumetric emissions cannot be converted directly to GHG mass emissions. Before volumetric natural gas emissions can be converted to GHG mass emissions, the volumetric natural gas emissions must first be converted to GHG volumetric emissions. Please confirm that emissions for blowdown vent stacks should be calculated using the following approach: volumetric natural gas emissions at standard conditions [98.233(i), Eq. W-14], convert to GHG volumetric emissions (CH_4 and CO_2) at standard conditions [98.233(u), Eq. W-35], convert to GHG mass emissions at standard conditions [98.233(v), Eq. W-36].

Response: EPA acknowledges the error and is considering ways to address this.

Question: For blowdown vent stacks the preamble indicates that blowdowns from containers less than 50 cubic feet total physical volume are exempt from reporting. However, requirements under 98.233(i) refer to "50 standard cubic feet", which could imply a gas volume rather than a physical container volume. In comments to the proposed Subpart W, GPA had suggested a threshold of 50 cubic feet of physical container volume and we assume that is the intent here. Please clarify.

Response: It is EPA's intent that the physical volume between isolation valves be considered against the 50 standard cubic feet threshold for blowdown vent stacks. Reference EPA-HQ-OAR-2009-0923-1018-27.

Question: The commenter requests the use of average blowdown volumes for sectors where this emission source is required (processing, transmission, and LNG imports/exports).

Response: Where section 98.232 requires reporting of emissions from blowdowns, reporters have to follow methods provided in section 98.233(i) of the rule.

Question: On Page 3 of the April 2011 FAQ list for Subpart W, the FAQ doc states, "Blowdown emissions from field equipment in the onshore petroleum and natural gas production segment are not included for reporting under the onshore petroleum and natural gas production industry segment; see section 98.231(a) and 98.232(c)." and on Page 10 of the it states that blowdown vent stacks are not covered per 98.232(c).

I agree that blowdown vent stacks are NOT covered.

But, if the blowdown gas from a facility or compressor at an onshore petroleum and natural gas production facility is routed to a flare, then based on 98.232(c) and 98.233(n) these

emissions to the flare would have to be reported.

Do you agree?

Some operators may interpret the FAQ as meaning all such blowdown gas does NOT have to be reported.

Response: If blowdown vent stack gas at an onshore production facility is routed to a flare, then these emissions will be reported as flare emissions and the calculation methodology in 98.233 (n) must be used. If you have a continuous flow measurement device on the volume to the flare, you must use the measured volume. If not, you can estimate flow using engineering calculations based on best available data or company records. For example, you may use the methods in 98.233(i) to estimate the volume of blowdown being sent to a flare.

Other: Compressors

Question: **With regards to the (Component Count Methodology 1), are tubing systems that are one half inch in diameter included in the totals shown on Tables W-1B and W-1C. If a component count exists for a facility, and the component totals are significantly higher than using the average component counts listed in Tables W-1B and W-1C, which count should be used?**

Response: Tubing systems equal to less than one half inch diameter are exempt from the requirements of section 98.233(r). If a component count exists for a facility, then that actual count may be used as required in section 98.233(r)(2)(ii).

Question: **In regard to emissions calculations for reciprocating compressor venting, specifically for production, using Equation W-29, why and how would I use Section 98.233 (u) to estimate volumetric GHGi emissions from volumetric natural gas emissions as outlined in the above section using Equation W-35? It appears as though Equation W-29 already calculates volumetric GHGi emissions and one should proceed to calculation of mass emissions with Equation W-36 from Section 98.233 (v).**

Response: Regarding calculating emissions from reciprocating compressor venting, it is EPA's intent that 40 CFR 98.233(p) should only reference paragraph 98.233(v) for determining mass emissions. EPA is currently considering options to address this.

Question: **I was seeking clarification on Subpart W, Section 98.233, Subsection (o), regarding calculation of emissions for Centrifugal compressor venting. From the regulation I am unclear as to the procedures for using Equations W-22 and W-23, specifically, are both calculations used independent of each other? If so, under what circumstances is one employed over the other?**

Response: The text in paragraphs 98.233(o)(4) and 98.233(o)(5) are not alternate methods. Per 98.234(o) compressors must be measured in all three modes over a 3 year period and therefore section 98.233(o)(4) is the calculation method for compressor modes measured during a specific reporting year and section 98.233(o)(5) is the calculation method for compressor modes not measured during the specific reporting year.

Question: **98.233(p)(10) for reciprocating compressors refers to applying the calculation methods found in paragraph (u) yet all equations in paragraph (p) calculate component volumes rather than total volumes. The similar section 98.233(o) for centrifugal compressors does not reference paragraph (u). It appears that the reference to paragraph (u) is in error in section (p)(10), please verify.**

Response: Paragraph (u) is incorrectly referenced in §98.233(p)(10). We are considering options to address this.

Question: **1. If reciprocating compressor venting emissions are controlled by a device other than a VRU (e.g., routed to a flare), do they still need to be measured/estimated under Subpart W? 98.233(p)(8) only mentions adjusting emissions downward when a VRU is used to control emissions. If a flare is used to control emissions, there would be no "venting emissions", and therefore these controlled emissions would not be reportable under 98.233(p).**

2. If reciprocating compressor venting emissions are controlled by a device other than a VRU (e.g., routed to a flare), are they required to be measured/estimated under Subpart W, are the compressor emissions estimated using the flare stack methodology identified in 98.233(n)?

Response: Section 98.233(p) does not provide any exclusion for reciprocating compressor venting emissions. Thank you for alerting EPA to the missing adjustment for emissions recovery in reciprocating compressor methodology; we are considering options to address this.

Question: **At any given facility, emissions from multiple vents on a compressor (e.g., rod packing vents and blowdown vents) may be routed through the same vent line such that the emissions cannot be measured for each vent individually. In this situation, how should vented emissions be determined for compliance with 98.233?**

Response: According to 98.233(o) you must monitor emissions from each isolation valve leakage, blowdown valve leakage, and wet seal degassing vent for each compressor individually. Please note that your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future. http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **Need clarification on what entity the "reporter" is in terms of developing the compressor emission factors for measurements conducted in the "as found" mode and applied to other compressors. This applies to processing, storage, transmission, and LNG**

operations. Is the "reporter" the facility, or all facilities operated by the same company?

Response: For purposes of developing the compressor emission factors for measurements conducted in the "as found" mode, EPA intended the "reporter" to be all facilities operated by the same company. In other words, the company could develop an emission factor, and apply it to all facilities operated by the same company. EPA has reviewed your question and cannot provide further guidance at this time. Your question relates to an issue or issues currently the subject of ongoing litigation. Please monitor the website for any additional guidance that may be available in the future. http://www.epa.gov/climatechange/emissions/subpart/w.html

Question: **In Subpart W, does a rotary screw compressor meet the definition of a centrifugal compressor in the rule. These units do operate using a rotating shaft; however, they are designed for high capacity and lower pressures than most common centrifugal compressors. rotary screw compressors operate on the principle of positive displacement (similar to reciprocating compressor) while centrifugal compressors depend on the transfer of energy from a rotating impeller to the gas being compressed.**

Response: In the context of sections 98.233 (o) and (p), EPA confirms that screw compressors and rotary vane compressors are not covered under 40 CFR 98, Subpart W.

Question: **Under Subpart W, reporters are required to directly measure emissions from centrifugal and reciprocating compressors. If the seals, rod packing, isolation valves, and blowdown valves all vent to a flare, are reporters still required to measure those emissions or can the flare gas composition and volume be used to estimate emissions?**

Response: Regardless of whether all emissions from centrifugal compressors and reciprocating compressors are sent to flare, emissions must be measured and reported using the methodologies specified in 98.233 (o)(1) through (o)(8) and 98.233 (p)(1) through (p)(7). The reporter cannot measure the flare gas composition and volume to determine the emissions from a particular centrifugal or reciprocating compressor.

Question: **Do we have to calculate and report emissions from dry seals?**

Response: 40 CFR 98.233(o) includes requirements to calculate emissions from both wet seals and dry seals.

Question: **Reciprocating Compressors: In the calculation of these emissions for these sources using equations W-27 and W-28 we calculate an emission factor, but we are unclear on where to use this emission factor in the calculation of the final emissions. Please clarify.**

Response: 98.233(p)(6) states, "estimate annual emissions using the flow measurement", which means Equation W-26 measures the emissions from compressor in the mode that it was found in the calendar year. 98.233(p)(7)(i) states that develop an emissions factor for "all the reporter's compressors not measured in the calendar year", which means that Equation W-28 develops an emission factor from measurements that were possible in specific modes.

Reporters must then use Equation W-27 to determine emissions from a compressor in the modes that it was not measured in during the current calendar year using a modal emission factor calculated in Equation W-28. The emission factors, parameter EFm, is on a modal basis and is calculated using metered emissions from the current year and the previous two calendar years in Equation W-28.

Question: **Centrifugal Compressors: In the calculation of these emissions for these sources using equations W-23 and W-24 we calculate an emission factor, but we are unclear on where to use this emission factor in the calculation of the final emissions. Please clarify.**

Response: 98.233(o)(4) states, "estimate annual emissions using the flow measurement", which means Equation W-22 measures the emissions from compressor in the mode that it was found in the calendar year. 98.233(o)(6) states that develop an emissions factor for "all the reporter's compressors not measured in the calendar year", which means that Equation W-24 develops an emission factor from measurements that were possible in specific modes. Reporters must then use Equation W-23 to determine emissions from a compressor in the modes that it was not measured in during the current calendar year. Equation W-24 determines the emission factors, parameter EFm, used in equation W-23. It should be noted that EFm is on a modal basis and is calculated using metered emissions from the current year and the previous two calendar years.

Question: **Non-operating pressurized mode for centrifugal compressors: The regulation recognizes only two modes for centrifugal compressors: operating and non-operating depressurized. While the non-operating pressurized mode is not typical, it does occur for certain centrifugal compressors with dry seals. Should direct measurements be taken if a centrifugal compressor is found in non-operating pressurized mode during the leak survey? Are emissions from this mode subject to reporting?**

Response: As the rule is currently stated per 98.233(o)(1) centrifugal compressors do not have to be monitored in the standby pressurized mode.

Question: **If a site has EOR compressors that handle critical phase CO2 for EOR, are they included?**

Response: If the compressor is a reciprocating or centrifugal compressor and is located in the onshore production facility as defined in 98.230 and 98.238 then the compressor has to be monitored per requirements in 98.233(o) or (p), as appropriate.

Question: **If a site has EOR compressors that handle to sub-critical phase CO2 for EOR, are they excluded?**

Response: If the compressor is a reciprocating or centrifugal compressor and is located in the onshore production facility as defined in 98.230 and 98.238 then the compressor has to be monitored per requirements in 98.233(o) or (p), as appropriate.

Question: 98.233(o) - Centrifugal Compressor Venting. It is not clear whether vapors leaving sour seal oil traps must be measured. It is assumed they would have to be measured using a temporary or permanent flow meter under 98.233(o)(2), but the paragraph refers only to installation of a permanent flow meter on the wet seal oil degassing tank. I believe the sour seal oil traps on compressors can vent through a closed system directly to flare. Ports for hot wire anemometers to quantify the seal oil trap vapor flow rate can require a facility shut-down in order to install; unless use of an acoustic device were allowable for closed systems.

Another issue of concern is the wording on the use of blind flanges. The paragraph is clear that if a compressor has blind flanges in place during the entire 3 year period, that measurements are not required. The interpretation is not clear however for a compressor that is taken off-line during a year, where the routine procedure is to install blind flanges before it is taken down. (i.e., the blind flanges would not be in place for the entire 3 year period.) There would not be an opportunity to measure a compressor in the standby depressurized mode if blind flanges are routinely installed prior compressor shut-down. Please verify that no venting measurements are required for a depressurized compressor found with blind flanges in place during the annual survey if the compressor is never placed in depressurized, not operating mode without blind flanges.

Response: This question has been responded to in the following two parts:

Sour Seal Oil Traps

Assuming that you mean by the term "sour seal oil traps" the seal oil-gas disengagement vessels that receive the inboard seal oil contaminated with entrained and dissolved compressed gas, then the rule treats these as seal oil degassing, and a vent either to the atmosphere or a flare or a vapor recovery device must be measured and reported: vent emissions as measured, flared emissions in accordance with 98.233(n) and vapor recovery operating factor deducting from the otherwise vented or flared emissions.

Depressurized compressor with Blind Flanges

No measurements are required by 98.233(o) or (p) on a compressor that is not in service for any time during the three consecutive year period. Therefore, if a compressor has blind flanges installed on the suction and discharge unit isolation valves for the entire three consecutive year period, then no measurements are needed. When a compressor is shut down for standby depressurized or maintenance modes, the rule requires measurement of blowdown vent emissions or alternatively measurement of unit isolation valve leakage using an acoustic through-valve leak detection instrument BEFORE blind flanges are installed on the unit isolation valves to assure no leakage of gas through the compressor. Unit isolation valve leakage cannot be measured with blind flanges in place, and the rule recognizes that there is normally a short period between compressor shutdown, isolation valve closure, and blowdown before the blind flanges are swung into place. Therefore, it is incumbent on the operator to plan and execute the through-valve leakage measurement on unit isolation valves during this short interval.

Other: Dehydrators

Question: 98.233(e) – Dehydrator vents. The regulation requires producers and processors to identify which dehydrators have a throughput less than 0.4 MMscf/day. Our clients expect that this would be based on actual annual average since this is an annual report of actual emissions.

Response: The daily throughput of 0.4 MMscf per day for dehydrators referenced in 98.233(e) is based on annual average daily throughput.

Question: How should the daily throughput be determined for dehydrators in 98.233(e) to compare to the threshold of 0.4 MMscf/day? Is it based on design capacity, maximum daily throughput, or annual average actual daily throughput? Is the throughput re-evaluated annually? If the throughput decreases below this threshold, are the equipment excluded from report under Subpart W?

Response: It is EPA's intent that reporters determine the daily throughput of 0.4 MMscf per day for dehydrators referenced in 98.233(e) based on annual average daily throughput. On an annual basis, the owner/operator must evaluate whether individual equipment falls above or below the equipment threshold and use monitoring methods appropriately. For less than of 0.4 MMscf per day throughput, the reporter must use 98.233(e)(2).

Question: Similarly, do dehydrators which are used to dry a liquid stream meet the definition of dehydrator (which states that units are used to dry a natural gas – i.e., gaseous – stream)? If a dehydrator which dries a liquid stream is considered a "dehydrator" (see question above), how does the 0.4 MMSCFD threshold apply to that dehydrator?

Response: No, per 98.6, a "dehydrator is a device in which "a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor."

Question: The emission methods for dehydrator vents <0.4 MMscfd in the preamble (use flow rate of wet NG and EF) contradict the requirements in the rule (use dehydrator count and EF).

Response: Reporters with dehydrators with throughputs less than 0.4 MMscfd must count such dehydrators and apply an emissions factor as provided in EquationW-5 to estimate emissions. Rule text supersedes preamble text where inconsistencies occur.

Question: For onshore petroleum and natural gas facility dehydrator vents at glycol dehydrators with throughputs less than 0.4 million standard cubic feet per day, can GRI-GLYCalc be used instead of Method 2 in §98.233(e)(2)?

Response: Emissions from glycol dehydrators with a throughput less than 0.4 million standard cubic feet per day must be reported using the requirements of 98.233 (e)(2), Calculation Methodology 2.

Question: **Under §98.233(e)(1), emissions must be calculated from dehydrator vents with throughput greater than or equal to 0.4 million standard cubic feet per day. Is this throughput specific to vent throughput or dehydrator throughput?**

Response: The 0.4 million standard cubic feet per day refers to the dehydrator throughput.

Question: **Subpart W 98.233(e)(1)(xi)(A) (related to dehydrator wet natural gas sampling) reads, "Use the wet natural gas composition as defined in paragraph (u)(2)(i) of this section."**

Is it correct that this is meant to only reference (u)(2)(i) which is only applicable to Onshore Petroleum and natural Gas Production Facilities?

Or, is it supposed to reference all of (u)(2), which would include other source categories as well?

Response: EPA intended the reference to be (u)(2)(i) and (u)(2)(ii) for onshore production and onshore processing respectively. EPA is considering options to address this.

Question: **This question relates to Subpart W calculation methodology for dehydrator vents.**

For dehydrators >=0.4 mmscfd, Calculation Methodology 1 98.233(e)(1) specifies that software that "speciates CH_4 and CO_2 emissions" shall be used.

For dehydrators <0.4 mmscfd, Calculation Methodology 2 98.233(e)(2) required equation W-5 which calculates speciated emissions only.

However, 98.233(e)(6) says "Both CH_4 and CO_2 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, particularly for dehydrators with <0.4 mmscfd throughput.

Response: EPA intended §98.233(e)(6) to apply to those calculations in §98.233(e) that yielded volumetric natural gas emissions. Since the method in §98.233(e)(1) and Equation W-5 speciate emissions, the calculations in paragraphs §98.233(u) and §98.233(v) are not necessary. Equation W-6, however, does yield volumetric natural gas emissions, therefore, the calculations in paragraphs §98.233(u) and §98.233(v) are necessary to speciate emissions. EPA is considering options to address this.

Question: **Is a software application necessary to calculate dehydrator vent emissions and storage tank emissions if flash gas is being sent to a flare? Can a reporter use engineering calculations and direct measurement to estimate volume to flare?**

Response: §98.233(e)(4)(A) states that for dehydrator vents to flares or regenerator fire-box/fire tubes "use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section." Therefore, consistent with (e)(1) and (e)(2), if the glycol dehydrator has a throughout greater than 0.4 million standard cubic feet then the CH_4 and CO_2 emissions must be determined using a software program prior to determining emissions from gas sent to flares. 98.233 (j)(7)(i) states that for flash gas sent to flare, "use your separator flash gas volume and gas composition as determined in this section." Therefore, if Calculation Methodology 1 is used, the CH_4 and CO_2 emissions must be determined using a software program to determine emissions sent to flares.

The calculation methodology of flare stacks in paragraph (n) is used to determine emissions from dehydrator vents sent to flares and flash gas sent to flares. In 98.233 (n)(1), the rule language states:

"If you have a continuous flow measurement device on the flare, you must use the measured flow volume to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data."

Therefore, a reporter can use direct measurement or engineering calculation to determine the volume to flare if the required conditions in 98.233(n)(1) are met.

Question: **This question relates to Subpart W, glycol dehydrator flash tanks.**

The rule requests:
98.233(e)(1)(viii) Use of flash tank separator (and disposition of recovered gas).
98.236(c)(4)(i)(D) Whether a flash tank separator is used in glycol dehydrator.

In a GlyCalc model, the only parameters required for the flash tank are the operating temperature and pressure. So what does EPA mean by "disposition of recovered gas", and why does EPA think this is a required parameter for the software model?

Response: 98.233(e)(1) states that "a minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators". Therefore, the items listed in 98.233(e)(1)(i)-(xi) are not all necessarily inputs. With item (viii) the reporter has to account for the flash tank separator used. As the question indicates, the input of operating temperature and pressure in GlyCalc model would account for the presence of a flash tank. The “disposition of recovered gas” means any recovery of flash gas and is covered in 98.233(e)(3) and (4)(B).

Other: Flaring

Question: For Equation W-21 - Flare Emissions: Do you use "5" for Ri (# of carbon atoms) for hydrocarbons with more than 5 carbons?

Response: For hydrocarbon constituents with 5 or more carbon atoms, Rj is 5 as defined in equation W-21.

Question: We noticed in Subpart W of the MRR on page 74498 (n) Flare Stack Emissions that the calculation methods do not offer use of a CEMS as a valid method of quantifying emissions for flare stacks. The Dehydration vent stack source category and the AGR unit vent stack source category both allow use of a CEMS to quantify emissions. Was it possibly an oversight to not allow use of a CEMS as a quantification method on flares? Most facilities are more likely to have a CEMS on the flare than the Dehy/AGR units, and given the extremely large variance in possible products going to the flare, the CEMS would likely be much more accurate than any calculation.

Response: You must follow the calculation and monitoring requirements in the rule. You are correct that 98.233(n) does not currently allow the use of CEMS as a method for quantifying emissions for flare stacks.

Question: Please confirm that flare stack emissions are included in determining applicability for Subpart W. That is, are flare emissions included in the 98.2(a)(3)(iii) combined emissions from all stationary fuel combustion sources when determining applicability for Subpart W per Section 98.231(a)?

Response: To determine facility applicability, you must determine if you meet the requirements of paragraphs 98.2(a)(1), (a)(2) or (a)(3). Based on the information provided we assume you meet the definition of the source category for subpart W and are only subject to reporting for subparts C and W.
Based on the assumptions above, for the 2010 reporting year, you are only required to report emissions from stationary combustion. When determining applicability under 98.2(a)(3)(iii) you do not need to include emissions from flares because flares are not included specifically under subpart C.

For the 2011 reporting year, you must include flare stack emissions in the applicability determination, as flares are included under subpart W.

Question: Subpart W 98.233(m), covering Associated Gas Venting and Flaring, assumes continuous gas venting or flaring throughout the year, which is typically the case for "stranded" gas from oil wells where gathering infrastructure is not available to route gas to sales. Equation W-18 uses total annual oil production with the appropriate GOR to capture

total gas emissions for the reporting year. In a situation where associated gas is only flared when an equipment disruption occurs, like a compressor going down for a short period of time, it is our interpretation that this quantity of flared gas does not fall within 98.232(m) since it is not continuous throughout the year, and therefore Equation W-18 would grossly overestimate emissions from the flaring event. Instead, our interpretation is that this flaring event should be reported under 98.232(n) [EPA note: should be 98.233(n)) that covers Flare Stack Emissions to allow for a more accurate reflection of the emissions from the flaring event.

Response: The interpretation on equipment disruption is correct; it has to be reported under 98.233(n) and not 98.233(m). Section 98.233(m) only covers natural gas that is not recovered from the production operation.

Question: **Why does EPA specify that reporters should subtract out volumes sent to flares to account for the portions of gas routed from dehys, completions and workovers. The flare emissions include all of the sources. This additional accounting is overly burdensome.**

Response: EPA requires tracking of flare emissions from individual sources of emissions to inform policy. See the response to EPA-HQ-OAR-2009-0923-1018-37 for further discussion on this subject.

Question: **98.233(n)(2)(ii) indicates that if a gas processing plant does not have a continuous gas composition analyzer, the composition of the flared stream depends on whether the gas flared is upstream of the demethanizer or downstream of the demethanizer. However, at gas processing facilities, flared gas can be a combination of gases before and after the demethanizer. In this situation, how is flare gas composition to be determined for use in Equations W-19 through W-21?**

Response: As per section 98.233(n)(1) the reporter shall estimate the proportion of flare gas upstream and downstream of the demethanizer and use the composition as determined in 98.233(n)(2) to determine flare gas emissions.

Question: **How is the composition for flare gas calculations determined if using a continuous analyzer (e.g., annual average)? Based on the Preamble, EPA is allowing reporters to use existing sampling data (e.g., composition analysis of gas sold) if reporters do not have a continuous gas composition analyzer already installed. This wording is more clear than 98.233(n)(2).**

Response: If using a continuous analyzer the reporter should use best representation of gas sent to flare. EPA's intent on gas composition of gas to flare is as provided in section 98.233(n)(2).

Question: **Under §98.232(e), emissions from flares are not a required source for calculation and reporting. Under section §98.233(o)(9), however, emissions from flares associated with centrifugal compressors must be reported. There are multiple cases throughout Subpart W**

where these confusions exist (i.e. section §98.233(k)(4), which is specific to the transmission compression industry segment). Please clarify which section of the rule is the correct guiding action.

Response: Under §98.232(e), the flare stack emission source is not required for reporting by natural gas compression facilities. However, this does not exclude the other emission sources listed in §98.232(e) if they are routed to a flare. The flare source type in 98.233(n) covers only emissions that are not reported in any of the other source types in 98.233; see 98.233(n)(9). For example, if transmission storage tank emissions are going to a flare then the rule requires the adjustment of transmission storage tank emissions sent to flare per section 98.233(k)(4). The transmission storage tank flare emissions, however, have to be reported as transmission storage tank emissions under 98.236(c)(9).

Question: **Is flare combustion reported separately?**

Response: All applicable industry segments must report emissions from flares. Emissions from sources listed under 98.233 that are routed to a flare must be reported under that particular emissions source, not under the flare source type to avoid double counting of emissions. Please see section 98.233(n)(9).

All hydrocarbon streams that are sent to a flare that result in CH_4, CO_2, and N_2O emissions must be reported under subpart W. Please see section 98.233(n)(2)(iii), which states "When the stream going to the flare is a hydrocarbon product stream, such as ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data."

Section 98.233(n) provides several methods to determine the composition of gas going to the flare. The reporter may either analyze the gas mixture before or after mixing as long as it is representative of the flare gas. This determination should be documented in the monitoring plan in 98.3(g).

Question: **Does a simple open pipe with no flare tip count as a flare under 98.233 (n) in Subpart W?**

Response: The flare definition in 98.6 does not indicate any exclusion, therefore, a simple open pipe with no flare tip is covered as a flare.

Question: **I wanted to confirm that for flares at onshore natural gas production facilities, CO2, CH4 and N2O should be reported; while at onshore natural gas processing facilities, only CO2 and CH4 should be reported. Is this correct?**

Response: You are required to report CO2, CH4 and N2O emissions for all flare stacks. 98.232(j) clearly states that all applicable industry segments must report the CO2, CH4 and N2O emissions from each flare. Flare stacks are included to be reported under natural gas processing facilities (98.232(d)(6)). The calculation methodology for flare stack emissions includes the method for quantifying N2O emissions from these stacks (See section 98.233(n)(8)).

Question: **Under Subpart W, under both the onshore production and gas processing source categories, are we required to report emissions from ALL flares at the gas processing facility or on/associated with a well pad? In particular, are emergency flares to be counted?**

Response: Yes, emergency flares are covered under the general category of flares, for reporting purposes EPA needs accurate data on flare emissions to better understand this emission source, including startup, shutdown and malfunction events, as flare use can vary significantly from day-to-day and year-to-year. EPA sought to reduce the burden associated with the flare monitoring and reporting requirements. In the final rule, EPA allows the use of engineering calculations based on process knowledge, company records, and best available data for estimating flow volumes; and for gas composition the use of appropriate gas compositions.

Question: In section 98.233(n) concerning calculation of emissions from flaring, paragraph (n)(8) provides a means of calculating N2O, however, nothing is said about converting this emission rate to CO2e. Should the N2O emissions be multiplied by the GWP for N2O similar to the procedure in paragraph (n)(6) for CO2 and CH4 then added to the total for CO2 and CH4 CO2e amounts as suggested in paragraph (n)(7)?

Response: Thank you for alerting EPA to the non availability of a method to convert the emission results from Eq. W-40 to metric tons CO2 equivalent; we are considering options to address this. You may use a multiplier of 310 to convert the metric tons of N2O into CO2e.

Question: **We noticed in Subpart W of the MRR on page 74498 (n) Flare Stack Emissions that the calculation methods do not offer use of a CEMS as a valid method of quantifying emissions for flare stacks. The dehydration vent stack source category and the AGR unit vent stack source category both allow use of a CEMS to quantify emissions. Was it possibly an oversight to not allow use of a CEMS as a quantification method on flares? Most facilities are more likely to have a CEMS on the flare than the dehy/AGR units, and given the extremely large variance in possible products going to the flare, the CEMS would likely be much more accurate than any calculation.**

Response: You must follow the calculation and monitoring requirements in the rule. You are correct that 98.233(n) does not allow the use of CEMS as a method for quantifying emissions for flare stacks. We may consider this issue further in future amendments to the rule.

Other: Pneumatic Devices

Question: **Equation W-1, legend entry for GHGi includes reference to facilities listed in 98.230(a)(3) through (a)(8). However, reporting for this source (pneumatic device venting) is required only for onshore production (which is specifically mentioned earlier in this legend item), and NG transmission compression and underground NG storage, which are 98.230(a)(4) and (a)(5) respectively. I recommend changing this reference in the legend to reference only (a)(4) and (a)(5), to avoid confusion.**

Response: For the source of pneumatic device venting, section §98.233(a)(1) and (a)(2) outlines the segments to be considered for emissions reporting from this source, in the definition of the term 'count'. Further, the definition of the term 'EF' highlights the sectors that are relevant for this source. The reference of sections §98.233(a)(3) through §98.233(a)(8) is a generic reference to the term 'GHGi.'

Leak Detection and Equipment Leaks

Question: **What types of equipment meet the requirements of Method 21? We understand that "Gas Rangers" qualify. What other brands of hand held gas wand devices qualify? Could you provide a list? Or could we rely on the vendor to certify compliance of the device? Method 21 provides specs in Section 6 – e.g., instrument scale readable to 2.5% of leak definition (or 250 ppm in this rule which is 2.5% of 10,000 ppm). Could EPA allow an option that does not require such fine resolution (e.g., if you can detect 10,000 ppm – the threshold for having a defined "leak" – it should not matter whether the device scale is readable to 250 ppm). Method 21 performance specifications may inadvertently exclude some devices that can accurately measure the leak threshold of 10,000 ppm. Does the rule provide an avenue to use those devices?**

Response: Method 21 describes industry practices reviewed and established by EPA as a standard for the measurement of volatile organic compound leaks. The methodology has been mutually accepted by EPA and industry and used in practice for many years, and EPA references it in the interest of reducing burden on the user and assuring consistency of measurements. As such, EPA also relies on the quality assurance standards built into Section 6.3 of the existing methodology, which specify that the "scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration;" in the case of Subpart W this translates to 2.5% of 10,000 ppm, or 250 ppm. Rather than recommending one particular type of brand of equipment, defining the methodology and instrumentation accuracy allows the user to select from a range of equipment options to best suit their individual situation.

Subpart W allows for facilities to use alternatives to the Method 21 approach and such provisions are outlined in the rule. For example, facilities are also given the option of using other methods such as an optical gas imaging device in the Alternative Work Practice to Method 21, or acoustic leak detection methods to monitor sources. For additional information, please see the response to comment EPA-HQ-OAR-2009-0923-1039-18.

Question: **Documentation for Leak Surveys of Components: What documentation is required for leak surveys? Must all connectors, block valves, control valves, pressure relief**

valves, office meters, regulators, and open ended lines be documented regardless if they are leaking or not. Currently, we check all connectors, valves, etc. but only document the actual leaks. If documentation will be needed on all components surveyed, then that would place an additional burden of recordkeeping and additional manpower will be needed to meet the requirements.

Response: For emissions source types indicted in 98.232(i)(1), the rule requires facilities to report the "total count of leaks found in each complete survey listed by date of survey and each type of leak source". Therefore, only leakers are to be reported, not the entire population of equipment/ components. Please refer to section 98.236(b) (15)(i). There are no recordkeeping requirements for emissions sources determined not to be leaking.

Question: **Option for Direct Measurement & Facility-Specific Emission Factors: Can a facility choose between (a) the provided emission factors or (b) conducting a statistical analysis and calculating a site-specific emission factor and applying it "across the board" to that facility and to other facilities with like equipment?**

Response: EPA requires that the reporters use emissions factors provided in the rule, except where a facility-specific emission factor is specifically required (e.g., above grade M&R at city gate stations). EPA does not allow for statistical analysis based emissions on a reporter by reporter basis as this cannot be verified easily and can result in non-standard reporting across the reporting facilities.

Question: **Can you tell me if the Hi Flow Sampler qualifies as a meter? It quantifies like any type of flow meter.**

Response: Section 98.234 (a) states that any of the methods including flow meters, calibrated bags, or high volume samplers may be used for quantifying equipment leaks and through-valve leakage. While EPA does not endorse a specific equipment manufacturer, high volume samplers (including the Hi Flow Sampler) can be used as a method for leak quantification as well as long as it conforms to requirements in 98.234(d).

Question: **Under Subpart W, Section 98.233 (q) addressing leak detection and leaker emission factors: Provided the streams with gas content greater than 10 percent methane plus carbon dioxide by weight are monitored, can monitoring data from a state permit required fugitive emissions monitoring program already in place, which has a lower leak detection rate of 500 ppm, be used to estimate fugitive greenhouse gas emissions?**

Response: You must follow the methods outlined in the rule. The reporter has to determine whether the concentration limits required by the state permit fall within or outside the 10 percent by weight methane plus carbon dioxide limit imposed by Subpart W. Concentration of GHGs in a leak cannot be always correlated with the weight percent of the GHGs in the stream that is leaking. This is because concentrations of GHGs in the leak are dependent on external factors that cause dispersion of the emissions. Hence EPA cannot provide concrete guidance on using State specified limits that are not directly comparable to Subpart W requirements.

Question: **In the "Leak Detection and leaker emission factor" subsection, I see that this section is not applicable to production. "You must...conduct leak detection of equipment leaks from all sources listed in Section98.232 (d7), (e7), (f5), (g3), (h4), and (i1). Therefore, I wanted to clarify that leak detection is not applicable for wellheads, separators at well site, storage tanks and other equipment defined by "production equipment".**

Response: Onshore production reporters do not need to perform leak detection under §98.233(q) for equipment leaks. For an onshore petroleum and natural gas production facility, equipment leaks are calculated with the methodology in §98.233 (r), using population count and population emissions factors.

Question: **Method 21 leak is a reading equal to or greater than 10,000 ppm. Does this include methane?**

Response: For subpart W the Method 21 leak definition concentration is 10,000 ppm methane.

Question: **Can leak repair logs be used to determine leak duration?**

Response: Leaks found during a single leak survey performed during the calendar year, must be assumed to be leaking since the beginning of the calendar year. If multiple complete leak detection surveys are conducted, reporters must assume that the component found to be leaking has been leaking since the previous survey whereby no leak was found or the beginning of the calendar year, whichever is more recent. See section 98.233(q) for further details.

Question: **Subsection 98.234(a)(4) states: "An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface." This seems straightforward, but we have encountered other entities who insist that other monitoring methods, such as other Method 21 compliant instruments, may be used in conjunction with manlifts to perform this monitoring. Are there circumstances, or component classes, for which use of other instruments and elevation of personnel is acceptable?**

Response: The final Subpart W rule does not allow for Method 21 compliant instruments to be used for inaccessible sources. Thank you for alerting EPA on this issue; we are considering options to address this.

Question: **Calculation section 98.233(r) regarding "Population Count and Emission Factors" states that "This paragraph applies to emissions sources listed in §98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), and (i)(5), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight." This does not contain any references to the source categories of "Onshore Natural Gas Processing" or "Onshore Natural Gas Transmission Compression".**

However, reporting section 98.236(c)(15)(ii)(A) states "For source categories §98.230(a)(3), (a)(4), (a)(5), (a)(6), and (a)(7), total count for each type of leak source in Tables W-2, W-3, W-4, W-5, and W-6 of this subpart for which there is a population emission factor, listed by major heading and component type." Source category 98.230(a)(3) is Onshore Natural Gas Processing and 98.230(a)(4) is Onshore Natural Gas Transmission Compression.

Please clarify which source categories are required to report for equipment leaks calculated using population count and factors (98.233(r))?

Response: All source categories in §98.230(a)(3), (a)(4), (a)(5), (a)(6), and (a)(7) are required to report the total count and type of leak source for which there is a population emission factor listed in Tables W-2, W-3, W-4, W-5, and W-6. Since there are no population emission factors listed in Table W-2 (for the processing segment), there is nothing to report under §98.236(c)(15)(ii)(A) for the processing segment. Pneumatic devices are reported under 98.236(c)(1).

Applicability Tool ?

Question: **Screening Tools – Especially for LNG Peak Shaving Facilities and Underground Storage: When and how will EPA develop its Screening Tools to help companies determine whether certain facilities do not need to report?**

Response: The screening tools are available on the website and are created to assist in the determination of which facilities are required to report under subpart W. Please see <http://www.epa.gov/climatechange/emissions/GHG-calculator/index.html >.

Question: **Any way we can get unlocked Subpart W screening spreadsheets (see attached) from the applicability tool?**

Response: No. EPA's intention in posting Subpart W calculation utilities is to provide facilities with a simple tool for estimating emissions when determining applicability. Additionally, the tools include a guidance and source tab to document how emission estimates were calculated. The utilities are only a guide to help facilities determine their Subpart W applicability. If you suspect a facility may exceed the annual 25,000 metric ton CO_2e threshold, you should refer to the calculation methodologies in 98.233 to determine emissions.

Question: **The applicability tool for Onshore Petroleum and Natural Gas has an operating factor for associated gas venting from produced hydrocarbons. How does this operating factor correlate with the barrels of crude oil produced?**

Response: EPA has provided guidance on the operating factor in the Notes section, where it states, "This is defined as the fraction of time the process unit is operating in a calendar year. For example, a 90% operating factor would be entered as 0.9 because the unit is in operation for 90% of the year."

Question: **For a 2011 report with the "Liquefied Natural Gas Storage" option selected; how does the "calculation utility" excel spreadsheet account for "Population Count & Emission Factors" when providing the user with a final CO2e number?**

Response: For the “Liquefied Natural Gas Storage” calculation utility, the spreadsheet multiplies Population Counts, Emission Factors, and conversion factors to output methane emissions in tonnes CO_2e for each source.

Final CO_2e emissions = (Population Count) x (Emission Factors) x (Volume conversion)

Question: **Where can I find the screening tool for onshore petroleum and natural gas production?**

Response: The screening tool for onshore petroleum and natural gas production is now available through EPA’s applicability tool at http://www.epa.gov/climatechange/emissions/GHG-calculator/index.html.

Question: **I am trying to determine Subpart W applicability for a facility that falls under source category onshore natural gas transmission compression. The calculation utility for onshore natural gas transmission compression makes note of the fact that GHG emissions from transmission storage tanks are not included in the calculation utility spreadsheet. The Subpart W preamble and rule, and EPA guidance document for this source category list transmission storage tanks as requiring direct measurement of emissions. Does EPA offer guidance on how to estimate a worst case scenario for GHG emissions from transmission storage tanks for purpose of determining applicability? Is there a default or assumed value for emissions from transmission storage tanks and that is why it was left out of the calculation utility?**

Response: EPA does not have sufficient data to characterize an average emissions factor for scrubber dump valve leakage through transmission storage tanks. Therefore, the calculation tool does not have this source built in. Hence, it is left to the facility to consider whether this is a significant source, including use of an acoustic detection device that has algorithms to quantify through-valve leakage from scrubber dump valves to determine applicability.

Question: **There are differences in the applicability tool calculation spreadsheets for the estimation of vented emission from reciprocating compressor rod-packing venting. In the Transmission Compression Tool the units are "number of compressor cylinders" while in the Underground NG Storage Tool the units are "number of compressors". What is the difference and which do you think should be used?**

Response: EPA has developed the calculation spreadsheets using best available data to help industry determine applicability. Based on the data available, EPA has developed factors on a per cylinder level and compressor level for transmission and underground storage segments, respectively. The transmission compression tool may be used for the transmission segment and the underground storage tool for underground storage segment. Please note that the applicability tool is intended to assist reporting facilities/owners in understanding key provisions of the rule. They are not intended to be a substitute for the rule.

Monitoring Plan

Question: **Subparts C and W: If a facility that operates stationary combustion equipment becomes subject the GHGRP due to Subpart W related emissions, does a GHG monitoring plan have to be put in place by January 1 or April 1, 2011 for the basic procedures that will be used to collect data necessary for Subpart C combustion emissions?**

Response: For Subpart W, monitoring plans as outlined in 40 CFR 98.237 were to be completed by April 1, 2011. This monitoring plan must include an explanation of the processes and methods used to collect the necessary data for all GHG calculations, including those in both subpart C and subpart W.

Best Available Monitoring Methods (BAMM)

Question: **The June 20th proposed amendments to 40 CFR 98.234(f) Best Available Monitoring Methods (BAMM) will grant automatic BAMM until December 31, 2011. As currently published, operators are required to submit BAMM extension requests by July 31st for BAMM extension until December 31st 2011. Does EPA expect to have a final rule published prior to the July 31st deadline operators currently face for BAMM extension requests?**

Response: You are correct that on April 25, 2011, EPA finalized a rule extending the deadline for submission of a request to use BAMM until July 31, 2011 (76 FR 22825). On June 27, 2011, a proposed rule was published in the Federal Register that would allow automatic use of BAMM for the entire 2011 reporting year for emissions sources covered under subpart W (Petroleum and Natural Gas Systems) without seeking approval from EPA (76 FR 37300). The public comment period for the proposed rule will be open through July 27, 2011. Given the timing necessary to consider public comment and finalize the rule, EPA will not be able to promulgate the final rule by July 31, 2011. Please note that 40 CFR 98.234(f)(1) indicates that "If the reporter anticipates the potential need for best available monitoring for sources for which they need to petition EPA and the situation is unresolved at the time of the deadline, reporters should submit written notice of this potential situation to EPA by the specified deadline for requests to be considered." EPA agrees that as of July 31, 2011, the circumstances surrounding the applicability of the deadline will be "unresolved" and that submitting a notification of intent would satisfy the rule requirements.

General

Question: Is there a PowerPoint presentation available on the reporting rule signed by Administrator Jackson on November 8, 2010 for the petroleum and natural gas facilities? We would like to share the presentation with our state technical advisory committee.

Response: A PowerPoint briefing on Subpart W, Petroleum and Natural Gas Systems, as well as other supporting materials are available on the Subpart W page of the Greenhouse Gas Reporting Program website at http://www.epa.gov/climatechange/emissions/subpart/w.html.

Question: Subpart W states that external combustion sources with rated heat capacity equal to or less than 5 MMbtu/hr do not need to report combustion emissions. Do the emissions from these sources need to be included in the 25,000 metric ton threshold determination?

Response: The emissions from external combustion equipment equal to or below the threshold do not have to be included in the determination of reporting threshold for the facility. Please see response to comment EPA-HQ-OAR-2009-0923-1060-27.

Question: My question concerns the calculation of standard temperature and pressure. The rule stipulates what standard temperature and pressure are, but how, for an annual average, is actual temperature and pressure defined. Is it conditions at the time data were collected? Is it the average temperature and pressure for a given location based on annual averages? Is it something else? Flow sensors are going to read actual CFM not SCFM.

Response: Actual temperature and pressure as defined for 98.233 is the "average atmospheric conditions or typical operating conditions." Therefore, the average temperature and pressure at a given location based on annual averages can be used for actual temperature and actual pressure.

Question: Should self-propelled workover equipment and truck loading/unloading be included for reporting GHG emissions under Subpart W?

Response: If the power take-off for operating the truck mounted workover rig is the truck wheel drive engine (i.e. a transmission option to transfer the truck wheel drive shaft to powering the rig generator or wench or other rig equipment) then yes, this workover rig arrangement is "self propelled." and not required to be reported. However, if the truck has a separate engine not connected to the drive wheels that powers the workover rig equipment, then it is "non-self propelled" and must be included in your report.

Question: How do I define a facility under subpart W? Are all industry segments included in one annual GHG report?

Response: An onshore production facility is defined in 40 CFR 98.238 and will report only those emissions from the emissions sources listed in 40 CFR 98.232. The onshore production facility has a single designated representative and does not include other industry segments or other source categories in its annual GHG report. Similarly, if a facility meets the definition for natural gas distribution that facility reports only what's listed in 98.232(i). All other industry segments under subpart W use the definition of facility in subpart A and report emissions in a single annual GHG report. Each facility must have one and only one designated representative. But, the same DR could represent multiple facilities. Other than onshore production and natural gas distribution, it is possible for a single facility to report under multiple industry segments. Please see requirements in 98.231(a) and response to comment EPA-HQ-OAR-2009-0923-1024-14 in the EPA's final Response to Public Comments Document for subpart W.