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THE IMPACT OF GREENHOUSE GAS MEASUREMENT
HOW RECENT REGULATIONS IMPACT THE MEASUREMENT OF GREENHOUSE GASES.
Class # 1350.1

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Introduction

The regulatory environment affecting the oil and gas (O&G) industry over the last two years has been rapidly changing and expanding. Unfortunately, the majority of regulatory changes have generally not been favorable to the industry. Among these regulatory developments, a key one has been the issuance of the first ever federal greenhouse gas (GHG) mandatory reporting regulation (MRR). The first set of these federal regulations was issued by the US Environmental Protection Agency (USEPA) on October 30, 2009 under 40 CFR Parts, 86, 87, 89 et al. encompassing a large variety of industries across the country. A subsequent set of regulations was issued on November 30, 2010 and this second set of regulations issued under 40 CFR 98, Subpart W encompasses all sectors of the O&G industry from wellhead to burner tip.

This paper covers the background of the GHG MRR, the various portions of the rules affecting the O&G industry, and the measurement and monitoring related requirements associated with the latest set of rulemaking delineated in 40 CFR 98, Subpart W (Petroleum and Natural Gas Systems).

Background and Development of the Rules

The USEPA was originally directed to develop GHG reporting rules under the Fiscal Year (FY) 2008 Consolidated Appropriations Act signed on December 26, 2007. This bill authorized funding for USEPA to develop and publish a GHG reporting rule by June 2009. This rule was subsequently delayed until October 2009. Ultimately, the USEPA determined it had the authority under Section 114 of the Clean Air Act to develop a reporting rule specifically to gather information on GHG emissions across all sectors of the economy. The initial rule issued in October 30, 2009 encompassed the 30 industry source categories included in Table 1.

Table 1
GHG MRR Subparts and Source Categories in October 30, 2009 Rule

Subpart A	General Provisions	Subpart X	Petrochemical Production
Subpart C	General Stationary Fuel Combustion Sources	Subpart Y	Petroleum Refineries
Subpart D	Electricity Generation	Subpart Z	Phosphoric Acid Production
Subpart E	Adipic Acid Production	Subpart AA	Pulp & Paper Manufacturing
Subpart F	Aluminum Production	Subpart BB	Silicon Carbide Production
Subpart G	Ammonia Manufacturing	Subpart CC	Soda Ash Manufacturing
Subpart H	Cement Production	Subpart EE	Titanium Dioxide Production
Subpart K	Ferroalloy Production	Subpart GG	Zinc Production
Subpart N	Glass Production	Subpart HH	Municipal Solid Waste Landfills

Table 1 GHG MRR Subparts and Source Categories in October 30, 2009 Rule			
Subpart O	HCFC-22 Production and HFC-23 Destruction	Subpart JJ	Manure Management
Subpart P	Hydrogen Production	Subpart LL	Suppliers of Coal-Based Liquid Fuels
Subpart Q	Iron & Steel Production	Subpart MM	Suppliers of Petroleum Products
Subpart R	Lead Production	Subpart NN	Suppliers of Natural Gas and Natural Gas Liquids
Subpart S	Lime Manufacturing	Subpart OO	Suppliers of Industrial Greenhouse Gases
Subpart U	Misc. Uses of Carbonate	Subpart PP	Suppliers of Carbon Dioxide
Subpart V	Nitric Acid Production		

The above source categories were required to register and submit a certificate of representation for affected facilities by January 30, 2011 and initially report GHG emissions by March 31, 2011 for the 2010 calendar year if the total emissions for a facility that includes the above source categories exceeds 25,000 metric tons per year of GHG emissions.

During this initial rulemaking in 2009, the USEPA had proposed an initial Subpart W that encompassed all sectors of the O&G industry, but they decided to defer that rulemaking to 2010 because of the huge volume of comments received on that subpart. They needed more time to fully address all comments in a more comprehensive rule. The USEPA subsequently issued an updated proposed Subpart W rule on April 12, 2010. This Subpart W rule was subsequently finalized on November 30, 2010 with an effective date of January 1, 2011. Administrative and technical amendments to the rule have since been published, most notably on November 29, 2011 (76 FR 73866), December 23rd, 2011 (76 FR 80544), and August 24th, 2012 (77 FR 51477). Table 2 provides a listing of the specific O&G industry sectors encompassed by this November 30, 2010 rule.

Table 2 O&G Industry Segments covered under Subpart W	
40 CFR 98, Subpart W (Petroleum and Natural Gas Systems	Offshore Production
	Onshore Production
	Onshore Natural Gas Processing
	Onshore Natural Gas Transmission Compression
	Underground Storage
	LNG Storage
	LNG Import & Export Equipment
	Natural Gas Distribution

Summary of Rules affecting Oil and Gas Industry

The initial rulemaking in 2009 and the subsequent updates in 2010 encompassed a variety of source categories specific to the O&G industry. The following lists the source categories potentially affecting the O&G industry in some manner.

- Subpart A: General Provisions
- Subpart C: Stationary Combustion
- Subpart D: Electricity Generation (if a cogeneration facility)
- Subpart W: Petroleum and Natural Gas Systems
- Subpart Y: Petroleum Refineries
- Subpart MM: Suppliers of Petroleum Products

- Subpart NN: Suppliers of Natural Gas and Natural Gas Liquids
- Subpart PP: Suppliers of Carbon Dioxide
- Subpart RR: Injection and Geologic Sequestration of Carbon Dioxide (finalized in 2010)

It is clear from the listing of all the source categories included in Tables 1 and 2 that the O&G industry has the most comprehensive coverage under this rule when compared to other industries that are typically only required to report under only one or two subparts of the rule. In comparison, a single O&G company could have to report under all nine of the above subparts. Because of the comprehensive nature of this GHG reporting rule, the scope of this paper has been limited to Subpart W because each of the above subparts has enough requirements that a separate paper could be written about each one. Therefore, the goal of this paper is to provide enough specific information on the single Subpart W category widely considered to be one of the most comprehensive reporting rules ever written that affects the O&G industry exclusively.

Summary of Petroleum and Natural Gas Systems Rule (40 CFR 98, Subpart W)

As discussed in prior sections, this paper will primarily cover the specific requirements associated with the Subpart W portion of the GHG MRR. The facilities subject to Subpart W must report the following GHGs under this rule.

- Carbon Dioxide (CO_2) and Methane (CH_4) emissions from equipment leaks and vents,
- CO_2, CH_4, and nitrous oxide (N_2O) emissions from combustion, and
- CO_2, CH_4, and N_2O from combustion at flares.

For consistency in reporting GHG emissions for all industry sectors, the above constituents are reported in a standardized form after the application of a scaling factor called a global warming potential (GWP). The standardized form is called CO_2 equivalent (CO_2e) emissions and the GWP for the above constituents are as follows:

- CO_2: GWP = 1
- CH_4: GWP = 21
- N_2O: GWP = 310

For example, a pound of CO_2 emissions equals one pound of CO_2e (or GHG emissions) and one pound of CH_4 equals 21 pounds of CO_2e (or GHG emissions).

The Subpart W portion of the GHG MRR encompasses all segments of the O&G industry from oil and gas production to local distribution companies. It is intended to require reporting of the CO_2, CH_4, and N_2O emissions from different equipment types and emission sources within the various segments of the industry. Table 3 provides a breakdown of the different source types covered within each industry segment. Although most of this equipment is found in many of these industry segments, it was the determination of the USEPA that the checked categories were the primary sources of GHG emissions that needed to be reported under Subpart W. There may be a rulemaking in the future or an amendment to Subpart W that will add more source categories to the respective industry segments.

Table 3
Summary of Subpart W Source Types in Each Industry Segment

Source Type	**OfP**	**OnP**	**NGP**	**NGT**	**UST**	**LNGSt**	**LNGI&E**	**DIS**
NG Pneumatic Device		**X**		**X**	**X**			
NG Driven Pneumatic Pumps		**X**						
Acid Gas Removal Vents		**X**	**X**					
Dehydrator Vents		**X**	**X**					
Well Venting for Liquids Unloading		**X**						
Gas well venting during well completions and workovers with hydraulic fracing		**X**						

Table 3
Summary of Subpart W Source Types in Each Industry Segment

Gas well venting during well completions and workovers without hydraulic fracing		X						
Blowdown vent stacks			X	X			X	
Onshore Production Storage Tanks		X						
Transmission Storage Tanks				X				
Well testing venting and flaring		X						
Associated gas venting and flaring		X						
Source Type	**OfP**	**OnP**	**NGP**	**NGT**	**UST**	**LNGSt**	**LNGI&E**	**DIS**
Flare Stacks		X	X					
Centrifugal Compressor Venting		X	X	X	X	X	X	
Reciprocating Compressor Rod Packing Venting		X	X	X	X	X	X	
Equipment Fugitive Leaks		X	X	X	X	X	X	X
Population Count and Emission Factor		X			X	X	X	X
Vented, Equipment Leaks and Flare Emissions Identified in BOEMRE GOADS Study	X							
Enhanced Oil Recovery hydrocarbon liquids dissolved CO_2		X						
Enhanced Oil Recovery Injection Pump Blowdown		X						
Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions		X						X

OfP: Offshore Production
OnP: Onshore Production
NGP: Onshore Natural Gas Processing
NGT: Onshore Natural Gas Transmission
UST: Underground Storage
LNGSt: LNG Storage
LNGI&E: LNG Import and export equipment
DIS: Distribution

Measurement and Monitoring Requirements Associated with Subpart W

The GHG MRR requires the development of a GHG Monitoring Plan by April 1, 2011 under Subpart A, 40 CFR 98.3 (g)(5) for each affected facility. This GHG Monitoring Plan is not required to be submitted to the USEPA, but it must be kept on file at each facility and it is considered a “living” document that needs to be updated periodically as changes occur. The GHG Monitoring Plan is essentially the foundation of a robust monitoring, measurement, recordkeeping, and reporting program for GHGs. The GHG monitoring plan needs to include the following components for each affected facility:

- Company name, facility name, address, and primary contact information
- Positions of responsibility
- Data collection methodologies
- Maintenance and repair procedures
- Monitoring, measurement, and QA/QC requirements
- Applicable engineering estimates and procedures being used
- Any best available monitoring methods (BAMM) being used

Each source type identified in Table 3 has specific methodologies delineated in the Subpart W rule that are used to determine the corresponding GHG emissions. The following sections briefly describe the methodologies and any measurement or monitoring requirements associated with the source type. Additional details associated with each of these methodologies are provided in 40 CFR 98.233.

- **Natural Gas Pneumatic Devices:** perform a count of the number of pneumatic devices for the affected facility and apply an EPA derived GHG emission factor to determine the GHG emissions for a calendar year. A representative count in the first and second year are acceptable, while a full count is mandated by the third reporting year.

    - Measurement Challenges: Performing full-field physical counts has proven to be a challenge for the onshore production segment, where pneumatic devices may be present on thousands of wellsites within a reporting basin. Logistically, it may be infeasible to survey every single wellsite in a basin. Therefore, application of alternative methods, such as determining counts according to make/model of major piece of equipment (providing this is a static number) may be necessary. This source category has proven to be a surprisingly large contributor to total basin emissions for the onshore production segment in some instances. It is likely that highly conservative EPA emission factors have resulted in emission estimates that may not be truly representative of leak conditions observed in the field, which may be highly variable based on operator, basin, age of equipment, etc. Trade associations, such as the American Petroleum Institute (API) are currently working to improve emission factor estimates, including a proposal to conduct field monitoring and research to develop an improved set of emission factors that can be applied to this source category.

- **Natural Gas Driven Pneumatic Pumps:** perform a count of the number of pneumatic driven pumps and apply a GHG emission factor to determine the GHG emissions for a calendar year

- **Acid Gas Removal Vents:** Four (4) different methodologies could be used to determine the GHG emissions associated with these types of vents for CO_2 emissions only.

    - Methodology 1: CO_2 data from a Continuous Emission Monitoring System (CEMS)
    - Methodology 2: Annual volume of vent gas (measured at ambient conditions) flowing out of the AGR measured using a flow meter and CO_2 volume percent of vent gas (recorded continuously or quarterly by a gas analyzer)
    - Methodology 3: Inlet and outlet natural gas flow measured by a flow meter (or use an engineering calculation to determine the flow rate) and volume fraction of CO_2 in the natural gas flowing into and out of the AGR measured continuously or quarterly by a gas analyzer or sales line quality specification for CO2 for the outlet gas.
    - Methodology 4: Process simulation software such as AspenTech HYSYS or AMINECalc
    - Three (3) Step Decision Tree:
        - Methodology 1: preferred approach
        - Methodology 2: if CEMS are not available, this would be the alternative method
        - Methodology 3 and 4: if methodology 2 is not available, either one of these methods could be used.

- **Dehydrator Vents:** Two (2) different methodologies for glycol dehydrators and a separate methodology for desiccant-type dehydrators.
    - Methodology 1 (glycol dehydrators >= 0.4 MMscf/day average annual actual throughput): GRI-GlyCALC 4.0 using a wet natural gas composition going into the dehydrator
    - Methodology 2 (glycol dehydrators < 0.4 MMscf/day average annual actual throughput): count number of these dehydrators and apply an emission factor specified in the rule
    - Methodology for desiccant-type dehydrators: determine volume of gas emitted during refilling of desiccant and GHG content.

- **Well venting for liquids unloading:** Three (3) different methodologies can be used to determine GHG emissions.

- Methodology 1: Metered flow at wellhead separator or atmospheric storage tank, average flow rate of venting per hour per tubing diameter and producing horizon in each producing field, cumulative hours of venting from all wells, GHG mole percent in natural gas
- Methodology 2: No plunger lift assist – casing diameter and well depth, number of vents per year, duration of each venting activity, temperature and shut-in pressure (psig)
- Methodology 3: With plunger lift assist - tubing diameter and depth, number of vents per year, duration of each venting activity, average sales flow rate of gas from the well, temperature and pressure of vented gas

- Measurement Challenges: All three methods require that the duration of the venting event is recorded. EPA has clarified that this should be total time that a well is left open to the atmosphere during an unloading event. In reality, there are instances where a well is open to the atmosphere for several hours or even days, but is only pressurized and venting a small fraction of that time. Application of the total time to emission calculations in these cases will substantially overestimate the amount of gas that is released to the atmosphere. Therefore, it may be necessary to instruct field technicians to log and record the subset of time that the well is actually pressurized and vents to the atmosphere, while noting that the well was open to the atmosphere for a longer period of time, but not venting.

- **Gas well venting during well completions and workovers with hydraulic fracturing: Option of** two (2) different equations to determine vented volumes:
  - Equation W-10A:
    - Methodology 1: Metered flow determined in each sub-basin (county and formation type) and well type (vertical or horizontal); or
    - Methodology 2: Record well flowing pressure and temperature upstream of well choke and flowing pressure downstream in subsonic flow and calculate a flow rate in each sub-basin and well type.
    - Measured (Methodology 1) or calculated (Methodology 2) flow rates are applied to all well completions or workovers for the same sub-basin and well type. The number of required measurements or calculations shall be determined per sub-basin and well type based on the the number of completions or workovers performed during the year. New flow rates shall be determined once every two years starting in the first calendar year of data collection.
  - Equation W-10B: Measure total flow volume of gas for every completion or workover using a recording flow meter on the vent line.

- **Gas well venting during well completions and workovers without hydraulic fracturing:**
  - Number of completions and workovers per field
  - Total annual gas production (in cubic feet)
  - Total number of hours that wells produced to sales line
  - Average daily gas production rate (in cubic feet per hour)
  - Amount of time each well completion was venting (hour/year)
  - Temperature and pressure of vented natural gas

- **Blowdown vent stacks:**
  - Equipment included in this source category: compressors, vessels, pipelines, headers, fractionators, and tanks
  - Equipment with physical volume < 50 cubic feet between isolation valves are exempt from this source category
  - Report volumes for blowdown venting of equipment that have a physical volume greater than or equal to 50 cubic feet between isolation valves
  - Track and keep records of the number of blowdowns per year for each equipment type

- **Onshore Production Storage Tanks:** Five (5) different methodologies can be used to determine GHG emissions from this source category
  - Methodology 1: Separators with average annual actual throughput greater than or equal to 10 bbl/day, use operating conditions in the last wellhead gas-liquid separator before transfer to storage tanks,
    - Use E&P Tanks software to determine emissions

- Separator oil composition, production rate, and temperature and pressure of oil
- Ambient air temperature and pressure
- Sales oil API gravity and Reid Vapor Pressure (RVP) of liquid

- Methodology 2: Separators with average annual actual throughput greater than or equal to 10 bbl/day, assume all CH_4 and CO_2 in solution is emitted, mass balance methodology
- Methodology 3: Storage tanks with average annual actual throughput greater than or equal to 10 bbl/day without separator
  - With actual oil and gas compositions: assume all CH_4 and CO_2 are emitted from tank
  - Without actual oil and gas compositions: use default parameters in E&P Tanks
- Methodology 4: Wells with oil production greater than or equal to 10 bbl/day that flow to a separator not at the wellpad
  - Use actual oil and gas compositions that are available and assume all of the CH_4 and CO_2 in the oil is emitted from the tank
  - If actual oil and gas compositions are not available; use default parameters in E&P Tanks
- Methodology 5: Separators less than 10 bbl/day, emission factors and total count of separators and wells
- Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year
  - Total time the dump valve is not closing properly during the calendar year.
- Measurement Challenges: Malfunctioning dump valves, while they may occur in the field, are very infrequent and hard to track and record. The relative frequency of these occurrences are disproportionate to the effort that it requires to manually track and record these events.

- **Transmission Storage Tanks:**
  - Uncontrolled: Visual leak detection using optical gas imaging or annually monitor leakage through compressor dump valves using an high flow sampler, calibrated bag or acoustic leak detection device.
  - Controlled: Estimate emissions using the flare stack methodology to determine storage tanks emissions from the flare
  - Measurement Challenges: For the Onshore Natural Gas Transmission Sector, the primary challenge has been safe and accurate measurements of the leakage from the dump valves of the storage tanks. Because of the typical rounded or cylindrical shape of storage tanks and inaccessibility of the dump valves, the measurements have required the use of special equipment such as a crane or manlift which have inherent safety and risk concerns in addition to limited availability especially for remote facilities. To address safety considerations, the rule does allow the use of an acoustic leak measurement device which can take safe measurements from ground level. However, industry does not recommend the use of such a device for measurement and reporting purposes because it has been determined to have a high level of uncertainty and inaccurate measurements. This device is better suited as an initial high level screening tool to help identify potential leaks. If leaks are found, more accurate measurement devices would then be used to take the actual measurements.

- **Well Testing Venting and Flaring:**
  - Gas to oil ratio (GOR)
  - Oil flow rate (bbl/day)
  - Number of days per year that the well is tested
  - Well testing emissions – to flares as control devices
  - Well testing emissions and gas composition data
  - Use flare stack methodology to determine emissions if controlled by a flare
  - Does not include testing that is considered part of the well completion

- **Associated Gas Venting and Flaring:**
  - Uncontrolled: GOR, annual oil production, produced natural gas composition (measure by gas analyzer continuously or quarterly), ambient temperature and pressure
  - Flare controlled: use flare stack methodology to determine emissions for CO_2, CH_4, and N_2O

- Measurement Challenges: The EPA equation assumes all gas is vented or flared, and does not allow for an adjustment in situations where only a portion of gas is flared and a portion is recovered to sales. This will overstate emissions in these situations.

- **Flare stacks:**
  - Metered vent gas flow rates or engineering estimates of vent gas going to the flare
  - Gas composition from gas analyzer or default parameters of feed natural gas or residue gas for natural gas facilities
  - For hydrocarbon stream going to flare, use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.
  - Flare combustion efficiency: provided by flare manufacturer or use a default of 98 percent
  - Flare emissions must be corrected for flare emissions that are calculated and reported under other sources to avoid double counting of emissions (i.e. emissions from compressor vent going to the flare would be reported under compressor venting, not flare)
  - Measurement Challenges: For onshore production, this source category may represent a very small, insignificant fraction of overall GHG emissions for this segment, since most emissions may be reported under other source categories. Sources reported in this category could include, as an example, pilot fuel consumption, drilling gas flaring, and oil well completion flaring. Given that these sources may represent an insignificant contribution to GHG emissions for this industry segment, requiring collection and reporting under this source category may represent an undue burden on operators.

- **Centrifugal Compressor Venting:**
  - Onshore petroleum and natural gas production facilities:
    - Count total population of centrifugal compressors and multiply by emission factor
  - Onshore natural gas processing, onshore natural gas transmission, underground natural gas storage, LNG storage, LNG import and export
    - Measure gas flow (scf/hour) through wet seal oil degassing vent in as found mode
    - Measure gas flow (scf/hour) through wet and dry seal compressor blowdown valve in as found operating mode
    - Measure gas flow (scf/hour) through wet and dry seal compressor unit isolation valve without blind flanges (not operating depressurized mode)
    - Total hours per year the compressor was in each mode of operation
    - Measurement: volumetric flow of wet seal oil degassing vents (permanent or temporary meter)
    - Measurement: volumetric flow of blowdown and isolation valves (calibrated bag, high volume sampler, acoustic detection or flow meters)
    - Track percentage of vented gas recovered for beneficial use
    - Determine GHG mole fraction in vent gas on an annual average
    - Track ambient temperature and pressure (for actual conditions, use average atmospheric conditions)
    - Must conduct a measurement of each compressor in the not operating, depressurized mode at least once every 3 calendar years.
  - Measurement Challenges: For onshore natural gas transmission, storage, and processing sectors, the safe access of the vents has been the primary challenge associated with these measurements. It has required the installation of measurement ports at a safer access point on some centrifugal compressor vents. There are inherent risks associated with the installation of measurement ports especially on blowdown vents when a unit(s) is operating; it could be blowdown at any time with little to no notice. In addition, the measurement of centrifugal compressor in the not operating, depressurized mode at least once every 3 years has been challenging to meet because this mode rarely occurs on some units so it may require a forced shutdown. The EPA has offered some relief from this “Not Operating, Depressurized Mode” measurement, but they have to approve on a case by case basis through the use of a Best Available Monitoring Method request.

- **Reciprocating Compressor Rod Packing Venting:**
    - Onshore petroleum and natural gas production facilities:
        - Count total population of reciprocating compressors and multiply by emission factor
    - Onshore natural gas processing, onshore natural gas transmission, underground natural gas storage, LNG storage, LNG import and export
        - Open ended vent line: Measure gas flow (scf/hour) through rod packing, blowdown vent, and unit isolation valve in as found mode
        - No open ended vent line:
            - Perform annual leak detection using optical gas imaging camera, Method 21, infrared laser, acoustic leak detection device
            - Measure flow rate of leaks with high flow sampler, calibrated bag, or an appropriate meter
        - Total time (hours/year) the compressor was in each mode of operation that was measured during that calendar year
        - GHG mole fraction in vent gas
        - Emission factor (developed by each company and specific to your compressors) is applied to each mode of operation not measured during that calendar year
        - Must conduct a measurement of each compressor in the not operating, depressurized mode at least once every 3 calendar years
    - Measurement Challenges: For onshore natural gas transmission, storage, and processing sectors, the safe access of the vents has been the primary challenge associated with these measurements. It has required the installation of measurement ports at a safer access point on some reciprocating compressor vents. There are inherent risks associated with the installation of measurement ports especially on blowdown vents when a unit(s) is operating; it could be blowdown at any time with little to no notice. In addition, the measurement of reciprocating compressors in the not operating, depressurized mode at least once every 3 years has been challenging to meet because this mode rarely occurs on some units so it may require a forced shutdown. The EPA has offered some relief from this “Not Operating, Depressurized Mode” measurement, but they have to approve on a case by case basis through the use of a Best Available Monitoring Method request.

- **Equipment Leaks and Population Counts:**
    - Annual leak survey using optical gas imaging, Method 21 – TVA 1000B, Infrared laser beam, acoustic leak detection device
    - Emission factors are then applied to the components found leaking during leak survey
    - Population counts (Onshore petroleum and natural gas production category):
        - Method 1: Count major pieces of equipment and multiply component count by default average components listed in Tables W-1B and W-1C of Subpart W
        - Method 2: Count each component and use the applicable emission factor in Table W-1A

- **Vented, Equipment Leaks and Flare Emissions Identified in BOEMRE GOADS Study:**
    - Methods outlined in the BOEMRE Gulfwide Emissions Inventory Study (GOADS)
    - Facilities reporting under GOADS must report same annual emissions as calculated by BOEMRE using activity data submitted by offshore platform operators
    - Facilities not reporting under GOADS: monthly activity data from applicable offshore production facilities must be collected in accordance with the latest GOADS program instructions and GHG emissions calculated in accordance with the latest GOADS study

- **Enhanced Oil Recovery (EOR) Hydrocarbon Liquids Dissolved CO_2:**
    - Calculate CO_2 emissions downstream of hydrocarbon liquids storage tanks associated with EOR
    - Perform annual liquids composition sampling downstream of the respective storage tank to determine mass of CO_2 dissolved in hydrocarbons beyond storage per barrel of produced liquid hydrocarbons

- **EOR Injection Pump Blowdown:**
    - Calculate CO_2 emissions from critical phase CO_2 EOR injection pump blowdowns

- Use engineering estimates and best available data to determine the volume of gas-containing structures between isolation valves
- Track and keep records of the annual number of blowdowns for each EOR pump
- Determine density of the supercritical EOR injection gas using a standard published by a consensus-based standards organization
- Calculate annual GHG emissions associated with EOR injection pump blowdowns using the number of blowdowns, volume of blown down equipment, mass fraction of CO_2 in the injection gas, the density of the injection gas, and a conversion factor

- **Onshore petroleum and natural gas production and natural gas distribution combustion emissions:**
    - If fuel combusted is listed in Table C-1 of Subpart C, utilize Tier 1 calculation methodology specified in Subpart C. This methodology allows the use of best available operating data for determining fuel consumption for the combustion sources combined with a default higher heating value
    - If fuel combusted is field gas or a combination of field gas or process vent gas and one or more fuels listed in Table C-1, need to use volume of fuel and composition of the fuel to calculate CO_2 emissions. The volume of the fuel and gas composition can be determined using a fuel meter and gas analyzer, or best engineering accepted methods.
    - GHG emissions from external fuel combustion sources with a rated heat input capacity less than or equal to 5 MMBtu/hr do not have to be reported. Only unit count by type of unit need to be reported for this category.
    Measurement Challenges: Collection of fuel usage and equipment counts for drilling and completion related equipment for onshore production operations has placed an additional burden on operators as most of this information needs to be obtained from third-party contractors. This entails investing additional time and effort to ensure that contractors provide accurate information in a timely manner. Counts of all combustion equipment, including equipment that falls below the combustion emission reporting threshold, need to be reported, which can be a very tedious process. Further issues may be encountered when tracking drill rig or completion rig fuel consumption. In many cases, total diesel consumption may be reported for the entire main rig tank wich includes all sources of diesel; however, this necessitates backing out fuel usage for equipment that falls below the reporting threshold which can be very difficult to track and monitor, and result in a level of effort that is disproportionate in comparison with the overall contribution to emissions.

Conclusion

This paper provides a brief summary of the recent GHG Mandatory Reporting Rule that has been developed and implemented since 2009 . This rulemaking is the first of its kind promulgated by the USEPA requiring GHG reporting on a nationwide scale beginning in 2011 for the 2010 reporting year. As outlined in the prior paragraphs, this rule has had the most profound impact on the O&G industry with the issuance of nine separate subparts that could trigger reporting for all sectors of the industry from wellhead to burner tip. The most comprehensive of these subparts is widely considered to be Subpart W (Petroleum and Natural Gas Systems) because it encompasses all segments of the O&G industry. This paper primarily focused on the specifics of Subpart W as it pertains to the measurement and monitoring requirements for the industry. Because of the broad scope and burdensome requirements associated with Subpart W, the national industry trade groups such as API, GPA, and INGAA and numerous smaller state and regional trade groups have and are still in the process of implementing extensive advocacy efforts to try to get revisions made to this rule to simplify some of the requirements and petition the USEPA for reconsideration of various parts of the rule. The advocacy efforts have been successful for revising some of the components of the rule and not so successful for other components. While some of these revisions have been implemented, it is still uncertain how many more revisions will be implemented in the near future that will directly affect measurements and emissions reporting for Subpart W.

References

1. 74 Federal Register, No. 209, 56260 to 56519 (to be codified at 40 C.F.R. pts. 86, 87, 89 et al.), Mandatory Reporting of Greenhouse Gases, October 30, 2009.
2. 75 Federal Register, No. 229, 74458 to 74515 (to be codified at 40 C.F.R pt. 98), Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, November 30, 2010.