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noble energy

June 11, 2010

Environmental Protection Agency
EPA Docket Center (EPA/DC)
Attention: Docket ID No. EPA-HQ-OAR-2009-0923
Mailcode 2822T
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Re: **Comments Regarding the Proposed Rule, Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems dated April 12, 2010 (75 FR 18608)**

Dear Docket Clerk:

Noble Energy, Inc. (Noble) respectfully submits these comments regarding the Proposed Rule, Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems (Proposed Rule) dated April 12, 2010 (75 FR 18608). The Proposed Rule addresses greenhouse gas (GHG) reporting requirements for GHG sources in the petroleum and natural gas sectors in Title 40, Part 98, Subpart W of the Code of Federal Regulations (40 CFR 98, Subpart W).

Noble Energy is an independent energy company engaged in worldwide oil and gas exploration and production. Noble primarily operates in the Rocky Mountains, Mid-Continent, and Gulf Coast areas in the United States, with key international operations offshore Israel and West Africa. Noble operates about 130 onshore petroleum and natural gas producing fields in the United States. These operations will be affected by the Proposed Rule requirements in Subpart W.

Noble has taken a proactive role on greenhouse gas emissions. Noble has voluntarily prepared annual domestic GHG inventories since 2006 and has publicly submitted its 2007 and 2008 GHG emissions to the Carbon Disclosure Project, and its 2008 emissions in its response to the Bloomberg Sustainability Survey. Over the past few years, Noble has continued to improve its GHG inventory through improved data collection methods and processes, improved emission estimation methodologies and emission factors, and has implemented several GHG emission reduction projects and initiatives. From this experience, Noble understands the complexity and level of effort required to collect all the necessary activity data and prepare a comprehensive, accurate, and thoroughly documented company-wide GHG emission inventory.

While the April 2010 Subpart W proposal includes several positive aspects, Noble still has concerns with the proposed Subpart W, including inclusion of several insignificant emission sources, overly burdensome emission estimation and reporting requirements, and the need for a phased approach to rule implementation. Noble comments provide analysis of onshore production emission sources and emission estimation methods, and recommend solutions to outstanding issues. Through these comments and cooperative ongoing dialogue with EPA, Noble believes that a technically-sound final rule can be developed that achieves EPA's reporting and policy objectives, and provides reporters clear, reasonable requirements for compliance certainty.

Noble Energy appreciates your consideration of these comments... Please contact me at 303-228-4015 or blockard@nobleenergyinc.com if you have any questions. Thank you.

Sincerely,

Brian K. Lockard, P.E.
Manager, Corporate Climate Policy
Noble Energy, Inc.

Attachment: Noble Energy Comments, Docket No. EPA-HQ-OAR-2009-0923, Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, dated April 12, 2010 (75 FR 18608)

cc by email: Roger Fernandez, US EPA

Comments on the Proposed Rule for
Mandatory Reporting of Greenhouse Gases

Proposed Addition to Code of Federal Regulations Title 40, Part 98

75 Federal Register 18608, April 12, 2010

Submitted by:
Noble Energy, Inc.
1625 Broadway
Suite 2200
Denver, CO 80202

Submitted to:
Docket ID No. EPA-HQ-OAR-2009-0923
U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
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Executive Summary

Noble Energy, Inc. (Noble) is an independent energy company engaged in worldwide oil and gas exploration and production. Noble primarily operates in the Rocky Mountains, Mid-Continent, and Gulf Coast areas in the United States, with key international operations offshore Israel and West Africa. Noble is a member of the American Exploration and Production Council (AXPC), Independent Petroleum Association of America (IPAA), America's Natural Gas Association, as well as other industrial trade representative organizations that participate in the public comment process of rulemakings. Although Noble supports many of the comments prepared by these and other trade associations, the potential burden and cost to Noble necessitates comment responses on Proposed Rule deficiencies that require revision, clarification, streamlined approaches, and implementation schedule revisions.

Noble brings unique and valuable commentary to this rulemaking process, in part, by having actual experience monitoring greenhouse gas (GHG) emissions. Noble has voluntarily prepared annual domestic GHG inventories since 2006 and has publicly submitted its 2007 and 2008 GHG emissions to the Carbon Disclosure Project, and its 2008 emissions in its response to the Bloomberg Sustainability Survey. Over the past few years, Noble has continued to improve its GHG inventory through improved data collection methods and processes, and improved emission estimation methodologies and emission factors. Noble has also implemented several GHG emission reduction projects and initiatives.

From experience, Noble understands the complexity and level of effort required to collect all the necessary activity data and prepare a comprehensive, accurate, and thoroughly documented company-wide GHG emission inventory. While the Subpart W proposal includes several positive aspects including selected use of emission factors and an attempt to focus on the primary sources for each Subpart W industry segment, Noble has identified a number of key issues that must be addressed before this rule can be finalized.

As detailed in the comments that follow, Noble's analysis of the Proposed Rule, together with its industry expertise and recent experience monitoring GHG emissions, conclude that the current draft of the Proposed Rule will be unduly burdensome, overly broad, and impose unreasonable costs on industry to comply. It will also result in no more useful information than could be gathered in less costly ways, and will create legal and practical uncertainty. To aid the EPA in formulating a final rule, Noble has five primary comments:

- Definition of Facility: The concept of a basin-level "reporting area" should replace the proposed definition of "onshore petroleum and natural gas production facility". The proposed Subpart W definition of facility for onshore petroleum and natural gas production is inconsistent with the facility definition for other CAA programs and will cause undo complexity for companies managing compliance with numerous air regulations. Designation of "reporting areas" for petroleum and natural gas production will establish the same Subpart W scope intended by EPA, without using an overly broad concept of facility. The §98.6 definition of facility should be retained and apply to onshore petroleum and natural gas production.

- Streamline Implementation to Reduce Compliance Costs: Noble analysis of the rule implementation cost estimate indicates the EPA costs are significantly underestimated and understated. The total estimated first year cost of compliance for Noble Energy alone is approximately $16,000,000 with an average of about $8.50/tonne CO2e. Table W-5 of the Proposed Rule preamble estimates the first year cost of compliance for the ***entire*** onshore production sector to be about $22,700,000 with an average of $0.18/tonne CO2e. The EPA cost estimate is about a factor of 50 lower than the Noble Energy estimate. Emission estimation requirements driving these costs include company-wide surveys (e.g. count every component, characterize every high-bleed pneumatic device, survey every gas flowline and intra-facility gathering pipeline), extensive process sampling (annual pressurized oil and water samples from every separator for production liquids storage tank emission estimates, quarterly samples of field gas for composition and production liquids for CO_2 content), and direct measurement requirements (e.g. reciprocating compressor rod packing vents).

  It is evident that several proposed emission estimation methodologies are cost-prohibitive, and it is recommended that alternative, simpler, more cost-effective, and streamlined emission estimation approaches be included. Noble recommends: 1.) equipment size thresholds under which reporting is not required and/or simpler emission estimation methods apply (e.g. exempt very small combustion equipment such as seasonal catalytic heaters, apply emission factors to dehydrators with low throughput); 2.) reduced frequency of measurements or process sampling, especially for invariant parameters (e.g. relax quarterly sampling requirements for field gas and production liquids), 3.) representative sampling and measurements to develop emission factors/data to estimate entire population emissions rather than test or sample every emission source (e.g. counting every component is overly burdensome and the component population could be accurately estimated from a random statistical sampling, estimate emissions from a random statistical sampling of production liquids storage tanks), and 4.) best available methods currently employed by industry (e.g. HYSIS® process simulation software, simple fuel use estimation methods for small combustion equipment based on burner rating and estimated operating hours).

- Eliminate Insignificant Sources From Reporting: Noble analysis of available GHG emission data for onshore petroleum and natural gas emission sources indicates the contributions of numerous sources to the overall inventory are insignificant. Including these sources is not consistent with EPA objectives to capture emission sources that comprise 80% of facility emissions and incurs significant burden with minimal benefit.

  For example, if the inventory only includes the nine largest onshore production GHG emission sources (refer to Table 2) which comprise approximately 85% of the U.S. inventory, then the estimated Noble total first year cost of compliance would be about $4,000,000 (compared to $16,000,000 for all sources) with an average of about $3.00/tonne CO2e (compared to $8.50/tonne CO2e for all sources). Thus, about 85% of the GHG emissions can be acquired for about a quarter of the cost of all the Proposed Rule emission sources; in other words, the smallest onshore production emission sources that comprise less than 20% of the GHG emissions inventory account for about 75% of the compliance costs.

Noble thus proposes eliminating insignificant proposed emission sources[1] from the reporting requirements to focus project resources on understanding emissions from the largest, most relevant GHG sources.

- Defer Reporting for One Year: Noble recommends deferring reporting for one year. Based on industry estimates of man-hour requirements, it is not feasible for industry to implement the Subpart W reporting program as proposed on January 1, 2010. For example, based on Proposed Rule requirements, Noble estimates that 26,000 man-hours will be required just to conduct equipment surveys (i.e. component counts, characterize pneumatic devices) and collect separator oil and water samples. In summary, Noble, and most if not all onshore production companies, does not have: 1) the necessary equipment to collect the process samples, and conduct the process and emission measurements on the scale required; 2.) trained personnel to operate that equipment; 3.) personnel and data management systems to collect, archive, interpret, and transmit the emissions information; or 4.) quality control procedures to ensure the integrity and completeness of the emissions information.
- Adopt a 3-Year Phase-In Implementation Schedule: A phase-in implementation schedule is necessary. In the first year, reporting would be required for emission sources that can be estimated using emission factors with readily available associated activity data (i.e. equipment counts and process rates). This schedule assumes that alternative, streamlined emission estimation methods will be applied, specifically, "representative sampling and measurements to develop emission factors/data to estimate entire population emissions rather than test or sample every emission source." Sources would include components, gas-driven pneumatic equipment, and combustion equipment not requiring installation of fuel flow meters or hour meters. In the second year, reporting would be required for emission sources that require the collection of process samples and development of associated safety procedures (i.e. for sampling high pressure process streams such as separators). Sources would include: oil/condensate and water storage tanks, and glycol dehydrator vents. The third year would incorporate reporting for emission sources that require direct emission measurements, installation of equipment to measure process flow rates, development of additional safety procedures (e.g. measuring elevated compressor vents), and/or acquiring data from third party operators. Sources would include combustion equipment that requires meter installation, reciprocating compressor rod packings, and well completions, workovers, and unloadings.

Noble's detailed comments follow.

[1] These sources include: Centrifugal Compressor Wet Seal Oil Degassing Vents, Dehydrator (Desiccant) Venting, Gas Well Venting During Conventional Well Completions and Workovers, Acid Gas Removal (AGR) Vent Stacks, Hydrocarbon Liquids Dissolved CO_2, Well Testing Venting and Flaring, EOR CO_2 Injection Pump Blowdowns, Natural Gas Driven Pneumatic Pumps, Coal Bed Methane (CBM) Produced Water Emissions, Reciprocating Compressor Rod Packing Vents, and Gathering Pipeline Fugitives.

Introduction and Background

Noble Energy, Inc. (Noble) is an independent energy company engaged in worldwide oil and gas exploration and production. Noble primarily operates in the Rocky Mountains, Mid-Continent, and Gulf Coast areas in the United States, with key international operations offshore Israel and West Africa. Noble is a member of the American Exploration and Production Council (AXPC), Independent Petroleum Association of America (IPAA), America's Natural Gas Association, as well as other industrial trade representative organizations that participate in the public comment process of rulemakings.

Noble brings unique and valuable commentary to this rulemaking process, in part, by having actual experience monitoring GHG emissions. Noble has voluntarily prepared annual company-wide GHG inventories since 2006 using emission estimation methodologies from the API Compendium and other industry standard GHG inventory guidance documents. Noble has continued to improve its GHG inventory through improved data collection methods and processes, and has implemented several GHG emission reduction projects and initiatives. For select sources where standard emission factors or methods do not accurately estimate emissions, Noble developed source-specific process data collection procedures and engineering calculations for more accurate estimates. These sources include well completions, well workovers, and well liquids unloading events. Thus Noble understands the complexity and level of effort required to collect all the necessary activity data and prepare a comprehensive, accurate, and thoroughly documented company-wide GHG emission inventory. Noble publicly submitted its 2007 and 2008 GHG emissions to the Climate Disclosure Project, and its 2008 emissions in its response to the Bloomberg Sustainability Survey. Noble has continued to improve its inventory through improved data collection methods and processes, improved emission estimation methodology and emission factors, and has implemented several GHG emission reduction projects and initiatives.

On April 12, 2010, the Proposed Rule, Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems (Proposed Rule) was published in the Federal Register at 75 FR 18608. The Proposed Rule addresses greenhouse gas (GHG) reporting requirements for GHG sources in the petroleum and natural gas sectors under Title 40, Part 98, Subpart W of the Code of Federal Regulations (40 CFR 98, Subpart W). In addition, GHG emissions from combustion equipment at subject Subpart W facilities are estimated according to requirements in Subpart C of the Mandatory Reporting Rule that was published in the Federal Register on October 20, 2009 at 74 FR 56260.

Noble respectfully submits these comments regarding the Proposed Rule. These comments primarily concern the Proposed Rule applicability to onshore petroleum and natural gas production. While the April 2010 Subpart W proposal includes several positive aspects including selected use of emission factors and an attempt to focus on the primary sources for each Subpart W industry segment, there are important issues that must be reconciled to facilitate implementation of Subpart W reporting and to provide clear, reasonable compliance criteria for subject facilities.

<u>Detailed Noble Energy, Inc. Comments</u>

I. The concept of "Reporting Area" should replace the proposed definition of "onshore petroleum and natural gas production facility." The Subpart W definition of facility for onshore petroleum and natural gas production is inconsistent with the facility definition for other CAA programs and will cause undo complexity for companies managing compliance with numerous air regulations. Designation of "reporting areas" for this Subpart W will establish the source category that EPA desires without using an overly board definition of "facility" that will result in confusion, uncertainty and practical application problems. The §98.6 definition of facility should be retained and apply to onshore petroleum and natural gas production.

The proposed term "onshore petroleum and natural gas production facility" (proposed 40 C.F.R. § 98.238) as currently drafted is overly-broad and will create legal and practical application uncertainty. First, the term in section 98.238 is overtly inconsistent with the definition of "facility" in 98.6, and the definition of "facility" as used under other Clean Air Act regulatory programs. The EPA's statement on its web posting (Subpart W FAQ, March 2010) states that ". . . the facility definitions proposed in this rule do no impact requirements under other EPA regulation, for example, New Source Review (NSR)." Noble appreciates that the EPA will limit this novel facility definition to reporting under Subpart W. However, this deviation from historical regulatory precedent and delineation of source boundaries and revised application of the term "facility" for this one GHG regulatory scheme will create undue confusion not only by the regulated community, but also among regulators. It further subjects both the regulated community and the EPA to litigation risk regarding the meaning and use of this term. Second, Subpart W appears to be the only subpart that imposes an expansive definition of "facility." All other subparts related to other source categories adhere to the term "facility" as defined in 40 C.F.R. § 98.6.

The objective of the proposed rule is to establish reporting requirements for facilities that emit greenhouse gases as contemplated by 40 C.F.R. § 98.1(a). This objective can be achieved for source categories subject to Subpart W without complicating the use of the term facility. To this end, Noble recommends the term "onshore petroleum and natural gas production facility" in section §98.238 be deleted in its entirety and replaced with a "reporting area". This concept of a "reporting area" is already being utilized by EPA in its currently proposed definition of "onshore petroleum and natural gas production facility," however it is used in a way that does not distinguish it from a "facility". ***More clarity and regulatory certainty is provided by clearly distinguishing "reporting area" from "facility" in this regulatory context.* .** Therefore, Noble recommends that the definition of "onshore petroleum and natural gas production facility" in §98.238 be amended and replaced with the following proposed definition of "onshore petroleum and natural gas production reporting area:"

> *Onshore petroleum and natural gas production* ~~*facility*~~ ***'reporting area'*** means all **facilities that contain** ~~petroleum or natural gas equipment associated with all~~ **onshore** petroleum ~~or~~ **and** natural gas production ~~wells~~ under ~~common ownership or~~ common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is

> assigned a three digit Geologic Province Code. Where an ~~operating entity~~ **onshore petroleum and natural gas production owner or operator** holds more than one permit in a basin, then all onshore petroleum and natural gas production ~~equipment~~ relating to all permits in their name in the basin is ~~one~~ **included in the same** onshore petroleum and natural gas production ~~facility~~ **reporting area**.

This proposed definition of "reporting area" clearly defines the geographic reporting boundaries for an owner or operator of onshore petroleum and natural gas production sources which are subject to the reporting requirements without creating confusion and uncertainty regarding the term "facility" or unintentionally expanding the meaning of "facility." It also applies to the triggering threshold of 25,000 metric tons of CO_2 or more per year required under 98.2(a)(2). Therefore, the above proposed definition of "reporting area" does not change sources subject to Subpart W nor what emissions are required to report. In addition, the §98.6 definition of facility should be retained and apply to onshore petroleum and natural gas production. The Proposed Rule language regarding reporting threshold should also be revised to accurately reflect the scope of sources subject to reporting and the geological range applicable to reporting. Therefore, Noble respectfully suggests the following revision to the proposed section 98.231, Reporting Threshold:

> (a) You must report GHG emissions from petroleum and natural gas systems if your **offshore petroleum and natural gas production, onshore natural gas processing plants, onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment, or natural gas distribution** facility as defined in §98.230 **or §98.238 or offshore petroleum and natural gas production reporting area as defined in §98.238** meets the requirements of §98.2(a)(2).

In addition, proposed section 98.231(b) should be deleted in its entirely as it creates ambiguity and unnecessary complexity for reporting threshold determinations. To provide further clarity that a reporting area must meet the reporting threshold, Noble proposes the following amendment to § 98.2:

> §98.2 Who must report?
>
> **An owner or operator of onshore petroleum and natural gas production facilities that have total emissions from all facilities located within an onshore petroleum and natural gas production reporting area (as defined in §98.238) of 25,000 metric tons CO2e or more per year**.

If EPA does not accept Noble's recommended revisions to the Proposed Rule's definition of offshore petroleum and natural gas production facility, Noble believes it is imperative that EPA include language in the Rule to state that the Rule's definition of offshore petroleum and natural gas production facility will not be applied elsewhere in the CAA and will not impact other EPA regulations.

Note to reader, in the comments that follow the familiar "facility" is often retained for consistency with the Proposed Rule language. As discussed above, "facility" would be replaced by "reporting area" in the final rule.

II. The GHG emission estimation requirements in the Proposed Rule are overly burdensome and EPA has not provided data quality objectives to justify the extensive costs. To address these issues, Nobles recommends that the Proposed Rule revisions to reduce burden while collecting GHG emissions data to develop a representative inventory that is no less useful include: removal of insignificant emission sources; reducing the frequency of emission and process measurements; adapting simpler, more cost-effective emission estimation methods; and representative sampling of large source populations.

Noble's cost estimate for rule implementation concluded the EPA cost estimates for rule implementation are more than an order of magnitude low and that many proposed emission estimation methodologies are cost-prohibitive. EPA has not defined or provided inventory or data quality objectives to justify these extensive costs. Noble analysis of the U.S. onshore production GHG emissions inventory indicates about a third of the affected emission sources contribute about 80% of the onshore production emissions. GHG emissions reporting should be limited to these and select other sources. The majority of the proposed emission sources for this sector are insignificant. The inclusion of these sources adds unnecessary and unproductive reporting burden, and it is recommended that they be removed from the reporting requirements.

In addition to removal of unnecessary emission sources, Nobles recommends that the Proposed Rule revisions to reduce burden while collecting GHG emissions data to develop a representative inventory include alternative, simpler, streamlined GHG emission estimation methods:

- Equipment size thresholds under which reporting is not required and/or alternative, simpler emission estimation methods (e.g. emission factors) apply;
- Reduced frequency of measurements or process sampling, especially for invariant parameters;
- Representative sampling and measurements to develop emission factors / data to estimate entire population emissions rather than test or sample every emission source; and
- Best available methods currently employed by industry.

These issues are further addressed in the following. Subsection A presents cost of compliance estimates for each of the onshore production emission sources. Subsection B analyzes the relative contribution of the onshore production emission sources and identifies insignificant sources. Subsection C provides summary analysis of the source contribution and cost analyses, and provides recommended proposed rule revisions to reduce burden while collecting GHG emission data commensurate with defined data quality objectives.

A. EPA cost estimates for rule implementation are estimated to be over an order of magnitude low. Several proposed required emission estimation methodologies are cost-prohibitive and simpler, streamlined methods should be included as alternatives.

Subpart W GHG reporting requirements include 21 emission sources for onshore petroleum and natural gas production. In addition, affected facilities (reporting areas) are required to report emissions from Subpart C combustion sources and also have requirements for characterizing field gas composition. These extensive reporting requirements - which require equipment calibration, equipment surveys, measurements, process samples, and recordkeeping - place an excessive and disproportionate burden on the onshore production sector. The locations of onshore exploration and production (E&P) sources (i.e. large geographic distribution), and lack of onsite power to automate data collection (e.g. manual data logs would be required) significantly add to the resources needed to implement the data collection and reporting requirements. The result is an excessive cost burden that has been significantly underestimated by EPA.

Mandatory Reporting Rule (MRR) compliance for onshore petroleum and natural gas production will require extensive effort including, but not limited to, direct emission and process measurements (e.g. flow meters), thousands of quarterly and annual process samples (e.g. storage tank liquids, separator liquids, gas samples), thousands of equipment surveys, calculations and data management for thousands of emission sources, and project management, record-keeping and reporting. Table 1 presents estimated Noble Energy costs for MRR compliance including first year (Year 1) and subsequent year (Year 2+) estimated $/tonne CO2e costs for each emission source and the entire Noble inventory. These cost estimates are based on the emission measurement and estimation methods prescribed in Subpart W and Subpart C, and GHG emission estimates from the Noble Energy 2008 inventory. Details regarding the data, methods, and assumptions used for these cost estimates are provided in Attachment A. These estimates provide guidance regarding emission sources where alternative, simpler emission estimation requirements and methods are needed for reasonable compliance costs.

Noble Energy onshore production operations include thousands of small stationary and portable fuel combustion units including compressor drivers, heaters, separators, and glycol dehydrator boilers. The majority of these small combustion equipment are at remote locations without a power source. It is assumed that simple fuel use estimation methods, such as burner ratings and estimated operating hours, rather than direct fuel and/or operating hour monitoring will be considered “company records” for Subpart C Tier 1 (e.g. §98.33(a)(1)) emission estimates. For example, the estimated cost to install and monitor mechanical totalizing flow meters on all affected combustion equipment exceeds the combined compliance costs for all other emission sources. Thus, as discussed below, combustion equipment firing rate threshold(s) to exclude small equipment and/or allow simple emission estimation methods are needed.

The total estimated first year cost of compliance is approximately $16,000,000 with an average of about $8.50/tonne CO2e. For subsequent years, the estimated total cost of compliance is approximately $11,000,000 with an average of about $6.00/tonne CO2e. Although, as noted in the table, emissions and/or cost estimates were not available for all the emission sources, it is expected that over 90% of the costs are included. It should be noted that companies that have different production field characteristics (e.g. well completions and workovers, compression and dehydration requirements, gas-driven pneumatic device population) would have a different mix of primary emission sources and different cost factors.

Table 1. Estimated Noble Energy Cost to Comply with MRR Subpart W and Subpart C for Onshore Petroleum and Natural Gas Production Emission Sources.

Emission Source	% of US Inv.[A]	NE Costs ($/tonne CO2e)[B]		Notes
		Year 1	Year 2+	
Well Venting for Liquids Unloading [98.233(f)]	24%	$11.00	$9.00	C
Associated Gas Venting and Flaring [§98.233(m)]	12%	$2.00	$1.70	
Gas Well Venting During Unconventional Well Completions and Workovers [98.233(g)]	12%	$1.20	$0.51	
Gas-Fired Reciprocating IC Engines (Combustion)	11%	$2.90	$2.50	
External Combustion: Heaters, boilers	8.4%	$3.70	$2.10	D
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	6.9%	$1.30	$0.19	
Portable Combustion Sources (Drill Rigs) [§98.233(z)]	6.6%	ND	ND	
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]	3.9%	$2.60	$0.37	
Dehydrator (glycol) Vent stacks [98.233(e)]	3.1%	$12.00	$10.00	
Components [§98.233(r)]	3.0%	$17.00	$2.401	
Produced Water Dissolved CO2 [§98.233(y)]	2.7%	$21.00	$18.00	E
Production Storage Tanks [98.233(j)]	2.2%	$18.00	$16.00	
Gathering Pipeline Fugitives [§98.233(r)]	1.6%	$46.00	$6.60	
Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	0.7%	$43.00	$24.00	
Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]	0.7%	-	-	F
Natural Gas driven pneumatic pumps [98.233(c)]	0.6%	$1.50	$0.54	
Centrifugal Compressor Wet Seal Oil Degassing Vent [§98.233(o)]	0.1%	ND	ND	
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	0.1%	$49.00	$7.40	
Gas Well Venting During Conventional Well Completions and Workovers [98.233(h)]	0.1%	ND	ND	
Dehydrator (Desiccant) Vent stacks [98.233(e)]	0.1%	ND	ND	
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	0.0%	$38,000.00	$33,000.00	
EOR Injection Pump Blowdown [§98.233(w)]	0.0%	ND	ND	G
Well Testing Venting and Flaring [§98.233(l)]	0.0%	NA	NA	H
Flare Stacks [§98.233(n)]	0.0%	NA	NA	I
Gas Composition [§98.233(u)]		NA	NA	J
TOTAL	**100.0%**	**$8.50**	**$5.90**	

ND – data not available

NA – not applicable

A. Estimated percent of US onshore production GHG inventory from Table 2.
B. 2010 dollars. Data management, calculations, record-keeping, and reporting costs allocated to emission sources proportional to source emission estimation cost.
C. Well Unloading emissions and compliance costs are expected to reduce as more plunger lift operations are automated and optimized.
D. Based on simple "company records" including burner rating and estimated operating hours. Assumed that totalizing flowmeters will ***not*** be installed on all external combustion equipment.

E. Emission estimate based on engineering judgment and assumptions and additional data needed to refine estimate.
F. Minimal compliance costs; emissions based on population emission factor and readily available production data.
G. Based on docket data, 500,000 pumps would be needed to account for about 0.1% of sector GHG emissions.
H. The majority of well tests are conducted while the wells are in operation and do not require flaring. Other well tests would be included in well completion and well workover estimates.
I. Flare emission estimates included in other emission source specific estimates.
J. Cost to collect and analyze gas samples included in Total but not included in costs for individual emission sources.

A review of the cost data in Table 1 shows:

- EPA has drastically underestimated the cost of rule compliance.
  - The total estimated first year cost of compliance for Noble Energy alone is approximately \$16,000,000 with an average of about \$8.50/tonne CO2e. Table W-5 of the proposed rule preamble estimates the first year cost of compliance for the ***entire*** onshore production sector to be about \$22,700,000 with an of \$0.18/tonne CO2e. The EPA cost estimate is about a factor of 50 lower than the Noble Energy estimate.
  - The total estimated cost of compliance for subsequent years for Noble Energy alone is approximately \$11,000,000 with an average of about \$6.00/tonne CO2e. Table W-5 of the proposed rule preamble estimates the subsequent years cost of compliance for the ***entire*** onshore production sector to be about \$8,600,000 with an of \$0.06/tonne CO2e. The EPA cost estimate is about two orders of magnitude lower than the Noble Energy estimate.
- Very high compliance costs for numerous emission sources indicate alternative, simpler emission estimation methods are needed or that these sources should be removed from the reporting requirements.
  - Annual costs for Hydrocarbon Liquids Dissolved CO_2 are about \$40,000/tonne CO2e. These costs are a result of this being a very small emission source (as shown in Table 2 below) and the requirement for quarterly sampling of liquid hydrocarbon storage tanks. As discussed below, this is an insignificant emission source to the total inventory.
  - Quarterly sampling requirements contribute to the high costs for Produced Water Dissolved CO_2 and Acid Gas Removal Vent Stacks. As discussed above, AGRs are an insignificant emission source to the total inventory.
  - Extensive process sampling requirements contribute to the high costs for Production Storage Tanks and Glycol Dehydrators.
  - Surveying thousands of well sites and annual tracking of new, decommissioned, and divested operations contribute to the high costs for Component and Gathering Pipeline Fugitives. As discussed below, available data indicate Gathering Pipeline Fugitives is an insignificant emission source to the total inventory.
  - Direct measurement requirements contribute to the high costs for Reciprocating Compressors Rod Packing Vents and Well Venting for Liquids Unloading. As discussed below, available data indicate Reciprocating Compressors Rod Packing Vents is an insignificant emission source to the total inventory.

In summary, Noble Energy has prepared a best estimate of the proposed rule costs based on its understanding of the proposed rule requirements and experience developing GHG emission inventories. However, rule changes and clarifications upon promulgation and as yet understood external factors (e.g. limited service providers and excessive demand (i.e. industry wide, millions of emission sources would require survey, sampling, and/or measurement), and complications with field measurements and process sampling) could significantly increase the costs above these estimates. In addition rule implementation costs to develop data management and archival systems will likely result in additional underestimated burden. Many of the proposed emission estimation methodologies are cost-prohibitive and alternative simpler, streamlined methods need to be provided. Alternative, simpler emission estimation methods are discussed in sub-section C.

Finally, as noted in Comment V, EPA should provide a practical applicability screening approach for rapidly and efficiently determining Rule subjectivity based on the 25,000 tonne per year CO_2e reporting threshold. The inability to determine rule applicability with a reasonable degree of certainty will require emission estimations for numerous small facilities to ensure compliance certainty. This significantly adds to the regulatory burden and it does not appear EPA has considered these costs for this rulemaking

B. **Analysis of the U.S. onshore production GHG emissions inventory indicates about a third of the affected emission sources contribute about 80% of the onshore production GHG emissions. It is recommended that EPA limit the reporting requirements to the largest onshore production emission sources that comprise 80% of the GHG emissions inventory and select other sources. Many proposed emission sources are insignificant for the production sector and their inclusion adds unnecessary reporting burden and does not inform future policy.**

EPA has not followed its own "80/20"guidance for including emission sources. Thus, the rule includes reporting requirements for many sources that are insignificant to the U.S. onshore production GHG inventory and should excluded from reporting. As noted in the preamble:

> "Typically, at petroleum and gas facilities, 80 percent or more of a facility's emissions come from approximately 10 percent of the emissions sources. EPA used this benchmark to reduce the number of emissions sources required for reporting while ***keeping the reporting burden to a minimum*** [emphasis added]. Sources in each segment of the petroleum and natural gas industry were sorted into two main categories: (1) the largest sources contributing to approximately 80 percent of the emissions from the segment, and (2) the sources contributing to the remaining 20 percent of the emissions from that particular segment. EPA assigned sources into these two groups by determining the emissions contribution of each emissions source to its relevant segment of the petroleum and gas industry, listing the emissions sources in a descending order, and identifying all the sources at the top that contribute to approximately 80 percent of the emissions. Generally, those ***sources that fell into approximately the top 80 percent were considered for inclusion***. [emphasis added]."

The Technical Support Document (TSD) [Docket Document EPA-HQ-OAR-2009-0923-0027] presents the 2006 U.S. GHG Inventory[2] for the oil and gas industry (pages 71 -78). The U.S. inventory for onshore production does not include all the Subpart W emission sources and, as noted in the TSD, vented GHG emissions for three sources: 1.) well blowdown venting for liquid unloading, 2.) unconventional well completions, and 3.) unconventional well workovers are underestimated by the U.S. GHG Inventory methodology. To better understand the relative source contributions for onshore production, Noble estimated the industry-wide/U.S. 2006 GHG emissions for each Subpart W and Subpart C affected emission source. The starting point for this inventory was the 2006 U.S. GHG Inventory emissions data presented in the Technical Support Document. For the three well venting sources noted above, revised emission estimates from the TSD were used. Other data gaps were addressed with data and information from: 1.) the TSD and the "Draft Onshore Threshold Analysis (Basin)" [Docket Document EPA-HQ-OAR-2009-0923-0015], 2.) GHG emissions data collected by Noble Energy for its API Compendium-based GHG inventory introduced in Section I, and 3.) engineering analysis. These emission estimates and the resultant U.S. inventory for affected onshore production emission sources are presented in Table 2. Attachment B provides additional detail regarding these estimates.

The GHG emissions were estimated using industry standard estimation methods based on available information and data, These methods include engineering estimates based on best available data and peer-reviewed API Compendium estimation methodologies, and emission factors based on field measurements and GRI/EPA studies conducted in the early-90's. The resulting emissions data provide relative source contribution and source significance within this sector's emission estimates.

Table 2 presents the emission source estimates from largest to smallest. The onshore production Subpart W sources and affected combustion sources are included. For each emission source, the estimated GHG emissions (tonne CO2e), the source's percentage of the total onshore production GHG inventory, and the cumulative percent of inventory at that source (i.e. percentage based sum of emissions from that source and all larger sources) are presented. The emissions data show:

- Approximately 81 % of the estimated GHG emissions are attributable to the following eight sources:
    - Well Venting for Liquids Unloading;
    - Associated Gas Venting and Flaring;
    - Gas-Fired Reciprocating IC Engines (Combustion);
    - External Combustion: Heaters, Boilers (Combustion);
    - Gas Well Venting During Unconventional Well Completions;
    - Natural Gas Pneumatic Bleed Devices (High or Continuous);
    - Portable Combustion Sources (Drilling Rigs); and
    - Natural Gas Pneumatic Bleed Devices (Low).

[2] EPA. *U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2007*. Available online at: <http://epa.gov/climatechange/emissions/usgginv_archive.html>.

Table 2. Estimated 2006 US GHG Inventory for MRR Subpart W and Subpart C Onshore Petroleum and Natural Gas Production Emission Sources.

Emission Source	CO2e tonne/yr)	% of Inv	Cumm %	Notes
Well Venting for Liquids Unloading [98.233(f)]	48,000,000	24%	24%	
Associated Gas Venting and Flaring [§98.233(m)]	24,000,000	12%	36%	
Gas-Fired Reciprocating IC Engines (Combustion)	22,000,000	11%	48%	
External Combustion: Heaters, boilers	16,000,000	8.4%	56%	
Gas Well Venting During Unconventional Well Completions [98.233(g)]	16,000,000	8.0%	64%	
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	13,000,000	6.9%	71%	
Portable Combustion Sources (Drill Rigs) [§98.233(z)]	13,000,000	6.6%	77%	
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]	7,700,000	3.9%	81%	
Gas Well Venting During Unconventional Well Workers [98.233(g]	7,000,000	3.6%	85%	
Dehydrator (glycol) Vent stacks [98.233(e)]	6,100,000	3.1%	88%	
Components [§98.233(r)]	6,000,000	3.0%	91%	
Produced Water Dissolved CO2 [§98.233(y)]	5,400,000	2.7%	94%	A
Production Storage Tanks [98.233(j)]	4,400,000	2.2%	96%	
Gathering Pipeline Fugitives [§98.233(r)]	3,066,000	1.6%	98%	
Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	1,423,000	0.7%	98%	
Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]	1,400,000	0.7%	99%	
Natural Gas driven pneumatic pumps [98.233(c)]	1,100,000	0.6%	100%	
Centrifugal Compressor Wet Seal Oil Degassing [§98.233(o)]	190,000	0.1%	100%	
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	150,000	0.1%	100%	
Gas Well Venting - Conventional Well Completions [98.233(h)]	130,000	0.1%	100%	
Dehydrator (Desiccant) Vent stacks [98.233(e)]	120,000	0.1%	100%	
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	8,700	0.0%	100%	
Gas Well Venting - Conventional Well Workovers [98.233(h]	6,700	0.0%	100%	
EOR Injection Pump Blowdown [§98.233(w)]	-	<0.1%	100%	B
Well Testing Venting and Flaring [§98.233(l)]	0	0.0%	100%	C
Flare Stacks [§98.233(n)]	-	-	100%	D
TOTAL	**200,000,000**	**100.0%**		

A. These emissions could be estimated by simulations of produced water tank emissions by E&P Tanks (as applicable) or other process simulators (e.g. HYSIS) using water samples collected for storage tanks.
B. Based on docket data, 500,000 pumps would be needed to account for 0.1% of sector GHG emissions.
C. The majority of well tests are conducted while the wells are in operation and do not require flaring. Other well tests would be included in well completion and well workover estimates.
D. Flare emission estimates included in other emission source specific estimates.

- Sixteen sources contribute less than 20 percent of the overall estimated GHG emissions inventory. These sources increase the regulatory burden and greatly add to the cost as shown in Table 1.
  - Of these sixteen "bottom 20%" emission sources, eight sources have estimated emissions of approximately 0.1% of the inventory or less. Even if these estimates are an order of magnitude low, each emission source would still contribute approximately 1% or less to the inventory and it is recommended that these be acknowledged as insignificant sources and excluded from reporting for onshore petroleum and natural gas production:
    - Centrifugal Compressor Wet Seal Oil Degassing Vents. Centrifugal compressors are not frequently employed for oil and gas production because reciprocating compressors have partial load operating advantages. Noble does not own or operate centrifugal compressors and Noble is not aware of any centrifugal compressors used in onshore oil and natural gas production. In addition, the prevalence and use of wet seals for centrifugal compressors have steadily decreased since wet seals were identified as a gas emission source; thus, it is expected that the few centrifugal compressors used for onshore production would primarily be equipped with dry seals;
    - Acid Gas Removal (AGR) Vent Stacks. Acid gas removal is predominately performed in the gas processing segment and AGRs are infrequently employed during production;
    - Gas Well Venting During Conventional Well Completions. Data presented in the TSD indicate that vented gas emissions from "conventional" well completions are orders of magnitude smaller than from "unconventional" well completions;
    - Dehydrator (Desiccant) Vent stacks. EPA Natural GasStar data[3] show emission from desiccant dehydrators to be less than 2% of glycol dehydrator emissions and this is a very small emission source;
    - Hydrocarbon Liquids Dissolved CO_2. Oil that has flashed in an atmospheric pressure storage tank would be expected to retain minimal amounts of gaseous compounds such as CO_2. The API Compendium notes that "once live crude reaches atmospheric pressure and the volatile CH_4/CO_2 has flashed off, the crude is considered "weathered" and the crude oil vapors contain very little, if any, CH_4 or CO_2."
    - Gas Well Venting During Conventional Well Workovers. Data presented in the TSD indicate that vented gas emissions from "conventional" well workovers are orders of magnitude smaller than from "unconventional" well workovers;
    - EOR CO_2 Injection Pump Blowdowns. Blowdown event volumes and frequency presented in docket documents indicate that tens of millions of these pumps would be needed for this to be a significant emission source; and
    - Well Testing Venting and Flaring. The majority of well tests are conducted while the wells are in operation and do not require flaring. Emissions from other well tests would be included in well completion and well workover estimates.

[3] "Replacing Glycol Dehydrators with Desiccant Dehydrators" http://www.epa.gov/gasstar/documents/ll_desde.pdf

These sources should be eliminated from 98.232 (c) (1) through (21) and from reporting requirements in Subpart W. If EPA elects to retain these sources, proper cost impact analysis and justification should be provided to support the cost effectiveness and data end use objectives for the GHG inventory.

For the remaining nine "bottom 20%" emission sources - Gas Well Venting During Unconventional Well Completions, Dehydrator (glycol) Vent stacks, Components, Produced Water Dissolved CO_2, Production Storage Tanks, Gathering Pipeline Fugitives, Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak)), Coal Bed Methane (CBM) Produced Water Emissions, and Natural Gas Driven Pneumatic Pumps - additional emission data collection and analysis to refine the emission estimates and better evaluate their potential significance (i.e. in the highest 80%) would be recommended.

In the TSD, EPA primarily references data and information from the U.S. GHG Inventory and EPA Natural GasStar studies to estimate emissions from and determine the significance of individual emission sources. Much of the U.S. GHG Inventory is based on emission factors developed from production equipment and operations in the early 1990's (i.e. the GRI/EPA Study[4]) and the GasStar data are often "data of opportunity" rather than from a representative sampling of industry sources. Thus, some emission estimates may not represent current equipment and operations. Examples of emission reductions since the GRI/EPA Study include LDAR programs to reduce fugitive emissions, flash tanks and combustion controls for glycol dehydrators, and other Gas STAR implemented recommended technologies and practices.

It is recommended that EPA investigate additional, more recent sources of GHG emissions data and refine the emission source estimates presented in the TSD (i.e. refine Table 2). Updated, more representative data will allow a better evaluation of the potential contribution of all the individual emission sources and determine which sources are most likely insignificant, significant (i.e. in the top 80% largest sources), and sources where additional data would be needed to better define contribution to the overall inventory.

Potential sources of additional, more recent GHG emission data include, but are not limited to, the Western Regional Air Partnership (WRAP), data collected for State Implementation Plans, state agencies, equipment and reagent sales (e.g. desiccants sales to industry by largest suppliers), and GHG reporting programs.

If this analysis is not completed, then Noble recommends that the Noble U.S. GHG Inventory presented in Table 2 be used to identify insignificant sources; thus, the eight sources discussed above would be considered insignificant and removed from the rule. In addition, it is further recommended that the remaining emission sources estimated to contribute less than 2% of the GHG inventory be acknowledged as insignificant sources and excluded from reporting for onshore petroleum and natural gas production:

- Gathering Pipeline Fugitives;

[4] GRI/EPA Reports, "Methane Emissions from the Natural Gas Industry", June 1996 (EPA -600/R-96-080)

- Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak);
- Coal Bed Methane (CBM) Produced Water Emissions; and
- Natural Gas Driven Pneumatic Pumps.

C. The GHG emission estimation requirements in the proposed rule are overly burdensome and EPA has not provided data quality objectives to justify the extensive costs. To address these issues, Nobles recommends that the Proposed Rule revisions to reduce burden while collecting GHG emission data commensurate with defined data quality objectives to develop a representative inventory that is no less useful include: 1.) removal of insignificant and unnecessary emission sources; 2.) reducing the frequency of emission and process measurements; 3.) adapting simpler, more cost-effective emission estimation methods for selected source types and sources below minimum thresholds; and representative sampling of large populations rather than every source estimates.

The data and analysis presented in the preceding sub-comments indicate that many of the emission sources required to report for the proposed rule are not significant contributors to the onshore production GHG inventory, and that many of the proposed rule emission estimation requirements are cost-prohibitive resulting in an unnecessary and disparate compliance cost burden for onshore production. It is noteworthy that Subpart W includes 21 emission sources for the onshore production segment whereas for other petroleum and gas industry segments is smaller number of emission sources (i.e. nine or less) were determined to be significant and required to report.

EPA has not provided data quality objectives other than to inform policy to justify these extensive and costly GHG emission estimation requirements. Noble Energy supports a reporting rule that collects data to estimate the majority of the onshore production GHG emissions; however, the level of effort should be reasonable, equitable (with other industries), cost-effective, and aligned to the ultimate use of the data. Requiring robust data collection in advance of developing and defining the objectives of the data is likely to result in data gaps, unnecessary data collection, and a data mismatch.

To this end, Noble Energy recommends the following:

- Data quality objectives should be defined to provide guidance on emission source inclusion and emission estimation method selection.
  - Percent of total sector emissions to be included in the inventory. For example, the proposed rule preamble and other supporting documentation have discussed including the largest emission sources that contribute to approximately 80 percent of the industry segment GHG emissions; and
  - Rational, justified, and clearly defined guidance regarding acceptable range of data accuracy and uncertainty for individual emission sources and the entire inventory. This

guidance should be closely aligned with the inventory and data objectives. For example, annual measurement or data collection should be technically justified based on observed variability and accuracy objectives, not a perception that increased frequency results in substantially improved estimates.

- A reduced number of onshore production emission sources required to report GHG emissions under Subpart W (i.e. §98.232(c)) and Subpart C.

  Remove sources identified as insignificant by the Noble U.S. inventory analysis. The Noble Energy analysis of the U.S. onshore petroleum and natural gas production GHG emissions inventory identified the following emission sources as very likely being insignificant sources: Centrifugal Compressor Wet Seal Oil Degassing Vents, Acid Gas Removal (AGR) Vent stacks, Gas Well Venting During Conventional Well Completions, Dehydrator (Desiccant) Venting, Hydrocarbon Liquids Dissolved CO_2, Gas Well Venting During Conventional Well Workovers, EOR Injection Pump Blowdowns, Well Testing Venting and Flaring, Gathering Pipeline Fugitives, Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak), Coal Bed Methane (CBM) Produced Water Emissions, and Natural Gas Driven Pneumatic Pumps.

  Noble recommends that these sources be acknowledged as insignificant sources and excluded from reporting for onshore petroleum and natural gas production. Alternatively, these immaterial/insignificant sources could be re-proposed for later addition as necessary to meet inventory and data quality objectives

- The "Portable Equipment Combustion Emissions" emission source is unnecessary and should be removed from all reporting requirements.

  Noble proposes that the EPA delete the portable non-self propelled equipment from the proposed definition of onshore petroleum and natural gas production and from all reporting requirements. Noble Energy supports comments on this issue submitted by AXPC and API. Portable Equipment Combustion Emissions reporting should not be required for onshore producers. This is because portable combustion equipment GHG emissions are predominately from diesel-powered drilling rigs operated by third parties, and well owner/operators would not maintain the equipment, control the day-to-day operation, or have ready access to the fuel consumption data required for reporting. Collecting the fuel use data would be very resource intensive and complex because an owner/operator often employs numerous drilling rig operators and drilling rig equipment is moved from well to well. In addition, diesel fuel use combustion is already reported under Subpart MM. In summary, MMR by onshore petroleum and natural gas production for portable non-self propelled equipment is unprecedented, results in double counting, and is impractical for portable sources outside of a reporting entity's operational control; and is thus unduly burdensome. For these reasons, Noble proposes that the onshore petroleum and natural gas production definition be revised as follows:

  > §98.230(a)(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production ~~equipment~~ means all ~~structures~~ **facilities** associated with ~~wells~~ **the production of petroleum or natural gas** (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines)~~, and~~

~~portable non-self propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment)~~ used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all EOR operations using CO2, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway.

- <u>The "Produced Water Dissolved CO_2" emission source is unnecessary and should be removed from all reporting requirements</u>.
  - The amount of GHGs (i.e. CO_2) that will be vented from produced water storage tanks will be estimated from the E&P Tanks simulations required for liquid storage tanks [98.233(j)] (or by HYSIS® or an alternative process simulation software if E&P Tanks is not appropriate for water streams); thus, quarterly sampling of produced water immediately downstream of the separator per 98.233(y) is not necessary.
  - As presented in sub-Comment A, the emission estimation methods for numerous emission sources are cost-prohibitive (i.e. have very high $/tonne CO2e) and alternative, streamlined emission estimation methods and approaches are needed. In addition, if sources identified as insignificant are retained in the MRR, alternative, simpler emission estimation methods and approaches should be applied. These alternative, simpler emission estimation methods and approaches include, but should not be limited to:
- <u>Equipment size thresholds under which reporting is not required or alternative, simpler emission estimation methods are provided</u>. A primary example is small combustion equipment at well sites such as heaters, glycol dehydrator boilers, and separators that are required to report emissions under Subpart W (portable equipment combustion emissions §98.233(z)) or Subpart C. As discussed above, rather than requiring all small equipment measure fuel use and/or operating hours per Subpart C Tier 1 estimates, equipment with a burner/fuel use rating less than a significant value should base emissions on very simple methods such as population emission factors and high level activity data such as annual months of operation based on operator records. A threshold value of 0.5 MMBtu/hr is recommended. GHG emissions from combustion equipment equal to or smaller than this threshold should be based on the methods recommended in Comment IV or similar methods. Further, Noble recommends exempting all natural gas fired equipment burning less than 100 MMBtu/year from reporting.

  Additional examples of alternative, simpler estimation methods are provided in Comment IV.
- <u>Reduced frequency of measurements or process sampling, especially for invariant parameters</u>. Quarterly sampling is required for numerous parameters such as field gas, AGR process gases, and hydrocarbon and water storage tank liquids. EPA has not provided or supported the technical basis for requiring this frequency. In addition, the

costs are excessive as demonstrated above and should be reduced to an annual basis or less.

Data gathered as part of this process should inform the correct sample frequency over time and the sampling frequency should be relaxed when it is demonstrated that the process parameters are not significantly varying over time. For example, if two consecutive gas samples show that the composition is varying by less than a threshold (e.g. change in methane content and carbon content is less than 10%), then sampling should be relaxed to every other period and then to every fourth period and so forth unless consecutive samples exceed the threshold. For sampling and measurement activities required annually (e.g. separator oil and water samples for storage tank emission estimates), similar criteria to relax sampling to bi- or tri-annual should be instituted.

- Representative sampling and measurements to develop emission factors / data to estimate entire population emissions rather than test or sample every emission source. The large number of onshore oil and gas production emission sources – e.g. about 800,000 wellheads nationwide, over 10,000 wellheads and 6,000 separators and storage tanks for Noble operations alone – preclude the cost-effective collection of required data and samples for each individual emission source. For example, it is estimated that on the order of 20,000 man-hours would be required to survey just the component counts in the Noble inventory, and components are a relatively small emission source (estimated to be about 3% of the total Subpart W inventory in Table 2).

  For each emission source, required parameters would be collected from a statistically random sample of the emission sources in a basin. The average emissions determined for the emission source (i.e. emission factor) would then be applied to each emission source in the basin to calculate the total emissions estimate. As data objectives and policy are better defined, a more robust data set will have been reported and serve as the basis for improving the sample size determination and data needs. To provide clarity and compliance assurance, Noble recommends that the maximum number of sources sampled each year in a basin would be 5% of the total or 30, whichever is less. The minimum number of sources sampled each year in a basin would be 5 or the entire population if less than 5.

- Best available methods currently employed by industry. EPA should provide for allowances to apply current industry standards or best practices. These include, but are not limited to: emission factors and estimation methods from the API Compendium or other GHG reporting reference documents, HYSIS and other process simulators, EPA and/or industry initiatives to collect data and develop better emission factors, and other industry standard approaches. Flexibility in selecting and applying emission estimation methods is discussed in greater detail in Comment IV. Industry has developed and used a multitude of emission estimation tools and methods to develop GHG emission inventories. Many of these are equivalent to or more rigorous than methods prescribed in the proposed rule. These methods should be allowed provided they are documented in the monitoring plan.

- A "phased-in" program as discussed in Comment III. A program that phases in different emission sources over a period of years will allow adequate time to acquire equipment, train personnel, and develop programmatic requirements such as data documentation and record-keeping. This approach would also facilitate data quality because more time will be available to address each program element.

III. Additional time is warranted for Subpart W implementation. It is not feasible to implement a program to collect the large amount of data required to report GHG emissions for the affected Subpart W and Subpart C emission sources in the Proposed Rule timeframe. The Proposed Rule implementation schedule should be delayed and/or emission source applicability should be phased in.

A. Defer Reporting for the First Year

It is not feasible for Noble to implement a program to collect the necessary data to report emissions for the 21 Subpart W and affected Subpart C emission sources in the proposed timeframe (i.e. commencing Year 1 on January 1, 2010). This fact is illustrated by simple analyses of the man-hour requirements:

- Noble has approximately 10,200 wells, assuming 2 hours (including time for travel and to compile data) are required to survey the components (i.e. conduct component counts) and pneumatic devices at each well and associated equipment, then an estimated 20,500 man-hours, 2,560 man-days, or 11.6 man-years would be needed;
  - Nationwide, assuming 750,000 wells, the level of effort to survey onshore petroleum and gas production components extrapolates to an estimated 1.5 million man-hours or 850 man-years.
- Noble has approximately 5,900 separators that dump liquids to one or more storage tanks and annual samples will be required for E&P Tanks simulations, assuming 1 hour (including time for travel and sample custody and shipping) are required to collect pressurized oil and water samples at each separator, an estimated 5,900 man-hours, 740 man-days, or 3.8 man-years would be needed; and

The above only addresses two of the emission sources and also does not include quarterly field gas samples for compositional analysis; this effort alone will annually require thousands of man-hours. In addition, the system required to maintain data records has not been developed or tested. Noble estimates that one to two years are required to develop and streamline such a system to tabulate the volume of data required by this rule.

In summary, Noble does not have: 1) the necessary equipment to collect the process samples and conduct the process and emission measurements on the scale required; 2.) trained personnel to operate that equipment; 3.) personnel and data management systems to collect, archive, interpret and transmit the emissions information; or 4.) quality control procedures to ensure the integrity and completeness of the emissions information. In addition, the new personnel and multitude of new measurements will necessitate development of new safety measures (e.g. for measurements at elevated locations) as discussed in Attachment C. It is very likely that most, if not all, affected onshore production companies face similar logistical challenges. Industry wide, component counting/equipment surveys and required measurements will be conducted by inexperienced contractors that represent what is currently an undeveloped and immature discipline. The extremely short supply of qualified personnel will be problematic and possibly insurmountable in the short-term. These factors are likely to drive up the cost of the service with the demand out pacing the available service providers during the initial few years.

Ideally, Noble recommends postponing the first year of reporting for one year, with 2012 emissions for Subpart W sources reported in March 2013. An alternative to the first year reporting would be to conduct an industry wide survey to complete population prevalence and GHG emissions estimates of the sources considered in this proposed rule. The need for this refined industry GHG inventory is discussed in Comment II. A stepwise process that builds upon the prevalent priority sources could then be established. This evaluation would provide more certainty for insignificant sources, and reduce the list of emission sources required to report.

B. Adopt a Three-Year Phase-In Implementation Schedule

There is insufficient time for industry to implement a program of this magnitude on January 1, 2011. Implementation should be delayed one year. Additionally, for all the reasons set forth above, a phase in approach for the rule is strongly recommended regardless of when reporting begins Noble believes that a phased approach for emissions estimation and measurement will provide a reasonable pace for collection of quality data to meet inventory objectives. In addition, a phased approach to rule implementation is necessary to develop estimation tools, training materials, and data management systems; hire and train personnel; specify, purchase, calibrate, and install measurement equipment; allow service provider growth to match demand; and reduce the cost burden.

Noble requests that EPA consider several possible alternatives that will facilitate rule implementation. Alternatives to consider include:

1. Phase in the emission sources that must be reported over multiple years– i.e., only a subset of the Subpart W and Subpart C onshore production emission sources become affected for the first few years of the rule. Noble recommends the following implementation schedule:

   Year 1 – Emission sources that can be estimated using emission factors with readily available associated activity data (i.e. equipment counts and process rates) and combustion sources that do not require installation of fuel flow or hour meters. This will also allow the development of database systems required to collect and track the quantity of data required by the Proposed Rule. Based on the proposed rule, these would include: Coal Bed Methane Produced Water Emissions, Natural Gas Driven Pneumatic Pumps, Natural Gas Pneumatic Bleed Devices (Low), Natural Gas Pneumatic Bleed Devices (High), Gathering Pipeline Fugitives, EOR Injection Pump Blowdowns, Dehydrator (Desiccant) Venting, Gas Well Venting During Conventional Completions and Workovers, and Components. This schedule is based on final rule inclusion of the Noble Energy Comment II recommendation for alternative, streamlined emission estimation methods and approaches; specifically, "representative sampling and measurements to develop emission factors / data to estimate entire population emissions rather than test or sample every emission source." That is, this schedule is not feasible if every well and pipeline must be surveyed.

Year 2 – Emission sources that require the collection of process samples development of additional safety procedures (i.e. for sampling high pressure process streams such as separators). Based on the proposed rule, these would include: Production Storage Tanks, Produced Water Dissolved CO_2, Hydrocarbon Liquids Dissolved CO_2, and Dehydrator (Glycol) Vent Stacks. This schedule is based on final rule inclusion of the Noble Energy Comment II recommendation for alternative, streamlined emission estimation methods and approaches; specifically, "representative sampling and measurements to develop emission factors / data to estimate entire population emissions rather than test or sample every emission source." That is, this schedule is not feasible if every storage tank and separator must be surveyed.

Year 3 – Emission sources that require direct emission measurements, installation of equipment to measure process flow rates, development of additional safety procedures (i.e. for sampling elevated compressor vents), and/or acquiring data from third party operators. These would include the remaining emission sources identified in the proposed rule.

After EPA has received and analyzed the data from Year 3, Noble recommends that EPA revisit collection data needs based on data gaps and policy decisions that may require additional data or have sufficient data (and reporting would no longer be required).

2. Allow "best available data" for at least year one, and preferably for the years one and two, for difficult to measure sources (i.e. the Year 3 sources from above) based on published emission factors and other emission estimation methods from the API Compendium and developed by Noble for its ongoing annual GHG inventory program. Noble prefers the previous options over this approach because this exercise would result in year one facility GHG emissions that differ from subsequent reporting years based solely on methods. This would lead to confusion when comparing subsequent reporting year data or among outside reviewers of the information.

IV. Flexibility to use alternative "best available" emission estimation methods is needed to avoid unnecessary burden while ensuring quality data. Noble recommends that the emission factors in Subpart W tables should be moved to a separate EPA reference document that is incorporated into the rule by reference.

Noble believes that reporting requirements must properly and equitably balance reporting burden with reasoned objectives for data quality and accuracy. As noted in Comment II-A, Noble believes that EPA has significantly understated the cost and burden of the rule, and has failed to define data quality objectives beyond informing future policy decisions. Many policy decisions could be made using current emission factor and engineering estimate approaches. The numerous proposed rule requirements for mandatory emissions measurement and monitoring results in a financial and resource burden that has not been adequately supported or justified.

To alleviate some of this burden, Noble recommends that emission estimation flexibility - that is, alternative "best available" emission estimation methods - be allowed. Although these methods may differ from those prescribed in Subpart W and Subpart C, their basis would be standard industry GHG protocols, such as the API Compendium, and company-specific data collection and engineering calculations developed for on-going annual inventory programs. To ensure data quality, the alternative methods would be documented in the Monitoring Plan.

Recommended alternative methods to reduce burden by allowing flexibility are listed below. However, this list should not be considered an all inclusive because companies have developed methodologies best suited for their equipment and operations.

- For small emission sources, the use of industry standard emission factors. For example:
  - For glycol dehydrators with throughput less than 3 MMcf/day, appropriate (i.e. considering use of flash separator and gas-assisted glycol pumps) emission factors from the API Compendium would be used rather than collect all the data and samples required for a GLYCalc® estimation. While the emission factor approach may not be accurate for some individual sources, for the population of sources errors average out and the emission factor estimates would provide quality data to inform policy decisions.
- For small combustion sources, the use of burner ratings and estimated operating hours rather than direct fuel and/or operating hour monitoring to estimate emissions. For example:
  - Especially during winter months, production fields employ numerous small heaters and other combustion systems. Separators fire periodically to maintain temperatures necessary to separate oil, water, and gas in the production fluid. The separator burner controllers are typically on/off systems; thus when the burners fire they combust gas at the rated capacity. Operators understand the annual duration of the separator burners operation and can estimate the number of hours of combustion.
- For estimating flash gas emissions from production liquids storage tanks, process simulators (such as HYSIS®), correlation equations (such as the Vasquez-Beggs Equations), and other approaches have been accepted by state agencies for years as accurate estimations of flash gas emissions and are appropriate for these estimates. Process simulations can also provide estimates of CO_2 dissolved in production liquids. For example it is not clear if E&P Tanks is appropriate for estimating emissions from produced water streams (as required for produced water storage tanks by §98.233(j); if E&P Tanks is not appropriate, then HYSIS® or an alternative process simulation software appropriate for water streams would be required;
- The use of mass balance determinations and alternative flow rate measurements.
- Noble supports Section VII of the API Subpart W comments and proposed alternative methods as outlined in this section.
  - Noble generally supports API comment regarding the following emission sources: natural gas pneumatic high bleed device venting, natural gas pneumatic low bleed device venting, well venting for liquids unloading, gas well venting during conventional well completions, gas well venting during conventional well workovers, reciprocating compressor rod packing venting, dehydrator vent stacks, storage Tanks, associated gas venting and flaring , centrifugal compressor wet seal degassing venting, coal bed methane produced water emissions, EOR injection pump blowdown, acid gas removal vent stack, hydrocarbon liquids dissolved $CO_{2,}$ produced water dissolved CO2, and fugitive emissions.

- Gas well venting during unconventional well completions and workovers: Noble supports the API comment regarding gas well venting during unconventional well completions and workovers. Additionally, Noble requests, as proposed by API, the flexibility of allowing the completion and work-over measurements (Method #1) or estimates (Method #2) to be completed for an even larger grouping. This grouping could be multiple producing horizons/formations, rather than a single producing horizon/formation, if the reservoir characteristics and behavior from the group of horizons/formations tend to be quite uniform and operators tend to use the same or very similar hydraulic fracture and well clean-up techniques and practices.
- Natural gas driven pneumatic pumps: Noble recommends the use of an emission factor(s) (such as the emission factor(s) for natural gas driven pneumatic pumps listed in the API Compendium) based on natural gas driven pneumatic pump counts in each reporting area to determine emissions from pneumatic pumps. If EPA does not support the use of the emission factor method, then Noble supports API's suggested alternative methods for natural gas pneumatic pumps.

In addition, **Noble strongly recommends that the emission factors in Subpart W tables (e.g., Tables W-1 and W-2) should be moved to a separate EPA reference document (such as or similar to AP-42 emission factors) that is incorporated into the rule by reference**. Reopening a rule to update emission factors would be difficult to accomplish and introduce unnecessary delays resulting in outdated emission factors. A separate EPA reference document should be developed and subjected to a peer review process. Subsequent updates will facilitate emission factor improvements and refinements from new and improved data that are collected and compiled. This reference document can be periodically revisited and updated to ensure that the best available data and emission factors are being used.

V. A streamlined rule applicability screening method is necessary to identify facilities that are not required to report EPA should provide a practical applicability screening approach for rapidly and efficiently determining Rule subjectivity based on the 25,000 tonne per year CO_2e reporting threshold. The inability to determine rule applicability with a reasonable degree of certainty will require emission estimations for numerous small facilities/reporting areas to ensure compliance certainty. This significantly adds to the regulatory burden and cost that have not been considered as part of this rulemaking. Noble strongly recommends that a streamlined applicability screening method be included in the rule for natural gas sector sources to preclude the need for monitoring and measurement in reporting areas that fall below the applicability threshold.

For onshore petroleum and natural gas production reporting areas covered by Subpart W, determining Proposed Rule applicability (i.e., annual GHG emissions above 25,000 metric tons CO2e) for a given facility/reporting area significantly undermines the benefits of that threshold for reporting areas covered under the Subpart. To initially determine whether a given reporting area exceeds the threshold for emissions reporting, the General Provisions require reporting area emissions be estimated using the measurement and monitoring methods prescribed in the Final Rule. In subsequent years, per §98.2(h), this estimate would need to be revisited to ensure that smaller reporting areas that did not previously report have not exceeded the reporting threshold in a subsequent year. Thus, while smaller reporting areas that do not report are relieved of the actual reporting burden, there is significantly more monitoring and measurement required than EPA estimates to ensure compliance.

The Proposed Rule essentially requires that Subpart W emission estimation methods (monitoring and direct measurement) be applied to every industry segment-specific source within an onshore petroleum and natural gas production reporting area every year. A screening method that provides reasonable compliance certainty is needed to avoid unnecessary compliance risk, implementation complexity, and financial burden.

Noble strongly recommends that a streamlined applicability screening method be included in the rule for natural gas sector sources to preclude the need for monitoring and measurement in reporting areas that fall below the applicability threshold. By defining an appropriate screening method and conservative screening emission threshold to identify affected reporting areas, compliance certainty can be assured and unnecessary measurement and monitoring can be avoided.

Noble believes a first tier screening estimate for onshore petroleum and natural gas production using a combination of API compendium emission estimation methods, and Natural Gas STAR and area specific emission factors with a threshold of 20,000 tonne CO2e per year is a reasonable screening approach. This approach would provide small reporting areas with relief from the extensive emission calculation methods, and provide compliance and reporting certainty.

Noble offers it assistance to EPA for future industry studies and data collection to refine screening tool(s) that will ensure reporting certainty for onshore petroleum and natural gas production owners and operators.

VI. Industry segment-specific sources to report in §98.232 should be clarified. Noble recommends that the industry segment be based on the primary NAICS code.

§98.232 lists eight Subpart W industry segments [i.e. (b) through (i)] and the emission sources to report for each segment. For onshore petroleum and natural gas production, 21 primary sources are identified. Noble supports EPA's intent to limit reporting to segment-specific sources listed in §98.232. However, additional clarifying rule text is needed to avoid unnecessary implementation questions.

Onshore petroleum and natural gas production and processing operations include an array of processes and equipment / source types, ownership, leasing, and arrangements that significantly complicate clear facility and source applicability delineation. For example, a central gathering facility that has liquid stabilization may have sources from onshore petroleum and natural gas production §98.232 (c), and also onshore natural gas processing §98.232 (d). In this example, the lack of clear segment delineation from the multi-use facility unnecessarily complicates rule interpretation, implementation and compliance. Noble understands that a facility is only required to report emissions from the sources listed in the applicable §98.232 subsection; that is, the source list is specifically defined and limited to those sources in the §98.232 subsection for that segment.

Noble further understands that the applicable segment is based on the primary facility function. The 21 emission sources in §98.232(c) are to be reported under Subpart W for onshore petroleum and natural gas production. If other emission sources applicable to another segment (i.e. beyond the 21 onshore production sources) are at a production facility (e.g., a blowdown vent stack), emissions reporting for that source is not required.

Further clarification directed toward accurately defined segment definition and source applicability is needed for unambiguous identification of over riding section of the rule. Noble does not advocate reporting under multiple segments and instead advocates a primary facility reporting segment and source requirements. These clarifications are required to ensure rule implementation and compliance issues do not arise. Noble recommends revisions to §98.232(a) to indicate the following (recommended added text is **bold**):

> "(a) You must report CO_2 and CH_4 emissions from each industry segment specified in paragraph (b) through (i) of this section **and only those sources specified for the industry segment shall be reported for an applicable facility under this subpart**."
>
> **(i) The industry segment specified in paragraph (b) through (i) shall be based on the primary NAICS code reported under §98.3(c)(10)(i).**
>
> **(ii) When the NAICS code includes multiple industry segments from paragraph (b) through (i) of this section, the industry segment shall be based on the activity that provides the primary source of revenue for a particular facility, which shall be reported along with the primary NAICS code in the annual report."**

Noble recommends that the primary North American Industry Classification System (NAICS) code reported for a facility serve as the basis to identify the applicable industry segment and §98.232 subsection. The language above, or similar text, should be added to section §98.232 to clarify the source segment for a particular facility. On April 12, 2010, EPA proposed amendments to Subpart A of the Mandatory Reporting Rule at 75 FR 18455 – 18468. The proposed amendments include the requirement for reporters to provide, "…their primary and all other applicable North American Industry Classification System (NAICS) code(s)". [75 FR 18455] If the Subpart A amendments are not finalized for reference in the Final Rule, the language provided in (a)(i) above could be revised to delete reference to Subpart A, but still provide similar criteria.

VII. Numerous reporting and recordkeeping, and missing data requirements appear to have limited utility and are not feasible, highly costly, or not warranted to support mandatory reporting rule objectives..

Reporting and recordkeeping requirements are identified in §98.236 and §98.237, and procedures for missing data are identified are §98.235. Noble Energy recommends revisions or clarification to these sections to eliminate requirements that are not practical or do not add substantive value while incurring unwarranted costs.

A. Missing data procedures should not require a repeat test in most cases.

Missing data requirements in §98.235 indicate "A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible…". This requirement is unnecessarily burdensome. Missing data procedures should consider the relative importance of the lost data and whether reasonable means are available to provide an estimate of that parameter before conducting repeat measurements.

For example, if a quarterly gas composition sample was not collected, or it was discovered after the fact that laboratory error resulted in no data, §98.235 would require a repeat test. Under these circumstances, the other three quarterly samples would be sufficient to determine an annual average composition and a re-sampling, months after the missing data event, would not be justified. As a second example, compressor vent gas measurements are conducted at ambient conditions, and if it is discovered after the fact that the ambient pressure was not recorded during a measurement, a repeat test would be required by §98.235. This would require test crew and operator remobilization, and could require operator actions such as man lift rental and process manipulation to achieve the proper operating mode (e.g., for multi-mode testing on reciprocating compressors). Rather than retest, ambient pressure could be determined from weather records from a station in proximity to the facility location. This would provide a very reasonable means to replace the missing data and calculate the vent gas flowrate at standard conditions. Even if the ambient pressure estimate was 0.5 "Hg in error, the resulting error in the flow correction to standard conditions would be approximately 2% or less. If suitable data from previous year(s) are available reasoned engineering judgment should be allowed and applied to complete the missing data and the estimate should be denoted as missing or errant data was replaced.

Although EPA has not addressed "materiality" or insignificant emissions in the Reporting Rule, sensible approaches to missing data that consider the relative impact of the data and whether reasonable alternatives are available should be allowed. For example, §98.3(i) provides accuracy requirements for device calibrations such that "All measurement devices shall be calibrated to an accuracy of 5 percent." §98.235 could include a similar threshold that requires that: (1) the operator to complete a repeat measurement unless replacement data or a reasonable estimate is available; (2) the operator document that a source-specific error of less than 5% would result; and (3) the basis for the replacement data and accuracy is documented in the annual report. It is in the best interest of operators to ensure that all data are routinely acquired and lost data issues do not occur; however, if EPA is concerned lost data allowances could be exploited; maximum usage of this allowance could be stipulated in the rule (e.g., no more than 10 % of emission sources in any annual report).

B. Recordkeeping and reporting requirements should be limited to reasonably accessible data that are required to achieve regulatory objectives.

The reporting requirements for the onshore petroleum and natural gas production emission sources included in §98.232(c) are listed in §98.236. Some of these requirements are infeasible, overly burdensome, and/or not pertinent to the reporting rule objectives or to inform future policy. Data objectives need to align with well defined policy objectives and purpose. Collecting additional data in anticipation of possible future use or emissions correlation is remiss.

Noble recommends deleting the following items from the list of reported parameters for §98.236 or including the affected parameter(s) in the Monitoring Plan required under §98.3(g)(5) rather than the annual report.

- <u>§98.236(c)(2) – Report emissions separately for standby equipment</u>: Separate reporting of emissions from "standby" equipment is not practical and should not be required for onshore production because the majority of these equipment are at remote, unmanned locations; thus, the time that the large number and variety of equipment are in a "standby" mode cannot be practically determined. In addition, "standby" is not defined in the MRR and can have different meaning for different types of equipment precluding compliance certainty.
- <u>§98.236(c)(4) – Acid gas removal (AGR) units</u>: AGR operating parameters – i.e., (i) through (iii) - are required for ***each*** unit; however, AGR emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual units; thus, the parameter reporting requirements have limited utility, add unnecessary burden to the reporting, and should not be included in the rule.
- <u>§98.236(c)(5) – Glycol dehydrators</u>: Glycol dehydrator operating parameters – i.e., (i) (A) through (B) - are required for ***each*** unit; however, glycol dehydrator emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual dehydrators. For these reasons, the parameter reporting requirements have limited utility, add unnecessary burden to the reporting considering the thousands of these emission sources, and should not be included in the rule.
- <u>§98.236(c)(10) – Production liquids storage tank emissions</u>: Production tank and associated operating parameters – i.e., (i) through (v) - are required for ***each*** unit; however, production liquids storage tank emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual tanks. For these reasons, the parameter reporting requirements have limited utility, add unnecessary burden to the reporting considering the tens of thousands of these emission sources, and should not be included in the rule.
- <u>§98.236(c)(14) – Flare stacks</u>: Flare stacks operating parameters – i.e., (i) through (v) - are required for ***each*** unit; however, flare stacks emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual flares. For these reasons, the parameter reporting requirements have limited utility, add unnecessary burden to the reporting considering the tens of thousands of these emission sources, and should not be included in the rule.
- <u>§98.236(c)(17) – Centrifugal compressor wet seals</u>: Centrifugal compressor operating parameters – i.e., (i) through (vii) - are required for ***each*** unit; however, centrifugal compressor wet seals emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual centrifugal compressor wet seals and degassing vents. For these reasons, the

parameter reporting requirements have limited utility, add unnecessary burden to the reporting, and should not be required. Specifically, compressor throughput is not readily available and reporting this parameter would add significant burden. This data is not expected to inform policy especially given the lack of these sources within E&P

- §98.236(c)(18) – Reciprocating compressor rod packing: Reciprocating compressor rod packing operating parameters – i.e., (i) through (vii) - are required for ***each*** unit; however, reciprocating compressor rod packing emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual reciprocating compressors. For these reasons, the parameter reporting requirements have limited utility, add unnecessary burden to the reporting considering the thousands of these emission sources, and should not be required.
- §98.236(c)(20) – EOR injection pump blowdowns: EOR injection pump blowdowns and associated operating parameters – i.e., (i) through (iv) - are required for ***each*** pump; however, EOR injection pump blowdowns emission estimates are reported in the aggregate per §98.236(a) and it would not be possible to correlate the reported emissions to the reported parameters for individual pumps. The parameter reporting requirements add unnecessary burden to the reporting considering the thousands of these emission sources and should not be required. Average values for items (i), (ii), and (iv) should be documented in the Monitoring Plan required under §98.3(g)(5) rather than the annual report
- §98.236(d): The requirement for "minimum, maximum and average throughput for each operation" is not clear and no explanation for the data use is provided. This requirement should be deleted or these terms and the intended data use should be clearly defined. If this is intended to require gas, oil, and water production values for facilities (basins), then a single throughput value is determined each year; that is, minimum, maximum, and average do not apply.
- §98.236(f): requirement is to "Report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters." Most onshore production combustion equipment, such as compressors and heaters (separators), are often rotated from a site for maintenance and/or if well conditions change and more appropriately sized equipment are needed. These equipment are often leased and operated or owned by third parties further encumbering data collection. The time that individual equipment is in service at a location is not routinely tracked and whether these equipment meet the definition of a stationary source or a portable source is not well known and can not be easily determined. What is known is the time that a site has equipment installed and operating, and these are the parameters needed for estimating GHG emissions using Subpart C methodology. Separate reporting of portable and stationary equipment emissions is not practical for most production combustion equipment, and would place undo burden on the reporters, and have no impact on the total reported GHG emissions; thus, Noble recommends that this requirement be removed. Drilling rigs are the one onshore production combustion source that would be considered "portable" under most, if not all, applications and the issue of drilling rigs is addressed in Comment II.

VIII. The definition of "onshore petroleum and natural gas production owner or operator" should be revised to clarify that royalty owners and non-operating interest owners be excluded from the revised definition.

State drilling permits are required to operate onshore petroleum and natural gas wells. Upon acceptance of a satisfactory bond, the state approves one operator per well; thus, MRR provisions for multiple operators are unnecessary. If such a circumstance were to exist where there could somehow be more than one operator for a well, requiring a new agreement would be unnecessary because multiple operators already necessitate a joint operating agreement, or equivalent agreement such as a force pooling order or unit operating agreement. While a joint operating agreement, or equivalent agreement, does not contain authority to bind other working interest owners, it does designate an operator. This designated operator would then be the reporting entity. Requiring additional agreements is unduly burdensome and superfluous. More than one entity holding a permit for or exercising operational control over individual equipment listed as sources in proposed section 98.230(a)(2), such as a pipe or a compressor, is rare; thus, provisions for multiple owners for proposed section 98.230(a)(2) sources other than wells are also unnecessary. But, to clarify ownership should the situation arise, Noble has proposed a catch-all provision in the below proposed definition whereby the entity with the greatest operational control shall be the owner or operator.

Noble has also proposed specifically excluding royalty owners and non-operators from the definition of an onshore petroleum and natural gas production owner or operator to remove any conflict with the owner or operator definition in Subpart A. A conflict in the definitions could result in daily filings of changes of ownership for royalty owners if such filings are required. For example, Noble operates thousands of wells in Colorado alone. A single, but representative, well in Colorado's Piceance Basin has 72 royalty owners. The preparation of a title opinion updating royalty owner information takes months and costs thousands of dollars. Royalty payments are made upon division of interest decks, which are CBI, and constitute one of the most litigated issues for onshore petroleum and natural gas producers. Providing royalty owner information will require filing for each change of ownership throughout the year, which are voluminous documents and clearly increase regulatory costs for regulated entities and the EPA. For all these reasons, Noble proposes the following amended definition:

> *Onshore petroleum and natural gas production owner or operator* means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state, which operates ~~an~~ onshore petroleum and/or natural gas production ~~facility~~ (as described in ~~§98.230(b)(2)~~ **§98.230(a)(2)**). Where more than one entity ~~are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility~~ holds legal or equitable title to or control over a source in section 98.230(a)(2), the entity exercising the greatest operational control over the source category shall be deemed the owner or operator designed to report all emissions. For all purposes of Subpart W, onshore petroleum and natural gas production owner or operator excludes any other person or entity who has legal or equitable title to, has a leasehold interest in, or

control of a facility or supplier or petroleum and natural gas well or source, including but not limited to royalty interest owners and non-operators."

Noble recommends that the language above, or similar text, be incorporated into the definition for onshore petroleum and natural gas production owner or operator in §98.6.

A. The scope of Subpart W reporting will be basin-wide; thus, the authorization of responsibilities and requirements at Subpart A at § 98.4 must be modified to be reasonably and appropriately applied to Subpart W onshore petroleum and natural gas production facilities.

Given that under Subpart W reporting is to occur on a basin-wide scope, the authorization of responsibilities and requirements at Subpart A at § 98.4 must be modified to be reasonably and appropriately applied to Subpart W facilities. Overlooking this need to reconcile Subpart A and Subpart W will cause significant and unjustified burden on onshore petroleum and natural gas production facilities subject to Subpart W.

IX. EPA should adopt a safe harbor policy for the first two annual submissions by those reporting under Subpart W whereby the EPA will presume that the submissions and calculations are being reported honestly and accurately, and that any errors are inadvertent.

The reporting required by Subpart W is unprecedented and will be implemented on an aggressive timeline. The goal of these reporting requirements is to obtain emissions data, and the reporting requirements should not penalize reporting that is done diligently, in good faith and on a timely basis. As the EPA and reporting entities monitor implementation of the reporting requirements, utilize best practices and streamline the process, the process will improve. Innovation is necessary. Some of these best practices have long-term potential and should be encouraged. The EPA should focus any enforcement efforts on those who do not report in good faith or intentionally submit false information. When other agencies have implemented unprecedented programs gathering aggressive amounts of data, they have employed a safe harbor policy for the initial reporting period where submissions are presumed to be made in good faith. *See*, FERC, *Policy Statement on Natural Gas and Electric Price Indices*, PL03-3-000 (July 24, 2003), PL03-3-001 (December 12, 2003). The EPA should not seek to prosecute or penalize errors in reporting unless those errors violated good faith standards, contained intentional submission of false or misleading data or intentionally failed to report data. In addition to delayed reporting and the phase-in approach Noble has requested in the above comments, Noble proposes that EPA adopt a safe harbor policy for the first two annual submissions by those reporting under Subpart W whereby the EPA will presume that the submissions and calculations are being reported honestly and accurately and that any errors are inadvertent.

X. Miscellaneous definitions, rule citations, clarifications, other issues.

This section itemizes a number of comments on issued not addressed elsewhere including clarifications or flawed rule text associated with definitions, rule section citations, and questionable grammar (i.e., poorly worded text).

- Noble recommends that EPA conform the definitions and terminology used throughout the proposed rule to be more consistent standard industry nomenclature to prevent errors and confusion.
- The rule should be consistent in defining standard conditions for expressing gas volumes and mass and in its use of nomenclature; that is, references to industry conditions, ambient conditions, actual conditions, and STP are confusing. Noble recommends that the rule consistently apply 60°F and 14.7 psia as the standard temperature and pressure; these are the units commonly used in GHG reporting protocols and referenced industry standards, and are the common units used for calibrating industry devices for custody transfer.
- 98.6 Definitions. Noble agrees with API comments concerning the definition regarding Fugitive Emissions.
- Noble requests clarification regarding definitions for "flowlines" and "intra-facility gathering lines" referenced in §98.230(a)(2) with the clarification that an owner/operator is responsible for reporting emissions from pipelines from the well, separator, compressor, etc. (as applicable) to the point of custody transfer.
- §98.233(j) Onshore production and processing storage tanks. The rule indicates that this source applies to "emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter.)" Noble believes that compliance with the requirement for "including stationary liquid storage not owned or operated by the reporter" is overly burdensome and will not be practical because a reporter may not have access to the necessary operational data (i.e. throughput) nor legal access to the tankage to collect required samples (e.g. sales oil for API gravity and Reid vapor pressure) to perform the required calculations. Therefore, Noble requests that this section only applies when the tank is owned or operated by the reporting entity.
- The flare N_2O emission factor in Table W-8 is based on MMCf gas production. An emission factor based on volume of gas combusted would be more appropriate.

XI. Conclusions

Noble shares the EPA desire to collect accurate, reliable and reasonably complete GHG emissions data for the natural gas sector. Noble also acknowledges the EPA desire to improve the quality of data on vented and fugitive emissions at onshore petroleum and natural gas production facilities. Additionally, Noble acknowledges and supports several aspects of the Proposed Rule including selected use of emission factors and an attempt to focus on the primary sources for each Subpart W industry segment.

However, Noble still has considerable concerns, and strongly urges EPA to thoughtfully consider and address issues identified in these comments. Noble's comments detail a number of concerns and recommended solutions, including the following key issues:

- The Subpart W definition of onshore petroleum and natural gas production facility should not differ from the traditional, existing CAA "facility" definition. The rule should rely on the existing CAA definition of facility and create roll-up "reporting areas" for capturing 80% of the GHG emissions from this industry segment;

- EPA should streamline implementation to reduce compliance costs;
- Eliminate insignificant sources from reporting;
- Eliminate portable equipment from the reporting requirements;
- Remove requirements for including sources not owned or under operational control of the reporting entity;
- There is insufficient time for industry to implement a program of this magnitude on January 1, 2011 and Noble recommends deferring implementation for a year. Regardless of when reporting begins, reporting should be phased in over 3 years to properly address GHG emission sources that require direct measurement or process samples to estimate emissions;
- An applicability screening method must be provided for Subpart W sources;
- Clarification is required regarding limitations in segment-specific source reporting;
- Prescriptive methods and technology requirements should be replaced with more flexible approaches;
- Subpart W emission factors should be moved to a separate EPA document that is incorporated into the rule by reference (such as AP-42, Compilation of Air Pollutant Emission Factors);
- Safety must not be compromised; and
- Clarity and unambiguous compliance criteria must be reflected in Subpart W.

Noble offers its assistance to reconcile the issues herein, and facilitate the development of viable Subpart W requirements for onshore petroleum and natural gas production facilities.

Attachment A – Documentation of Estimated MRR Compliance Costs for Noble Energy Onshore Petroleum and Natural Gas Production Operations

This attachment describes the data and methods that were used to estimate Mandatory Reporting Rule compliance costs for Noble Energy onshore petroleum and natural gas production sources affected by Subpart W and Subpart C. Compliance costs were estimated for most of the affected emission sources and for preparing the entire inventory. The GHG emissions data that are the basis for the majority of the estimates are from the Noble Energy 2008 GHG emission inventory. This inventory is primarily based on emission estimation methods from and consistent with the API Compendium. For some of the emission sources that are not included in the Noble inventory, emissions were estimated using Subpart W or Subpart C methods if applicable activity data were available. Emissions could not be estimated for some sources.

Table A.1 provides summary information for each affected emission source. As available, CO2e emission estimates from the Noble 2008 are presented with estimated compliance costs for the first year (i.e. Year 1) and subsequent years (i.e. Year 2+). Estimated compliance costs are presented as $/tonne CO2e for the emission source. These costs include physical sample collection and analysis and/or direct measurements, engineering calculations (e.g. E&P Tanks), equipment calibrations, personnel training, recordkeeping, emission source level and rolled up calculations, and reporting. Based on Noble's interpretation of the rule requirements, the last column details the data, methods, and assumptions (e.g. survey and/or measurement of different emission sources during a single site visit) used to estimate the costs. As would be expected at this stage of a rulemaking, there is considerable uncertainty in these cost estimates. In addition to the assumptions discussed in the Table A.1, other factors that could impact costs include a shortage of service providers and trained personnel, and excessive demand (i.e. industry wide, millions of emission sources would require survey, sampling, and/or measurement), and complications with field measurements and process sampling (e.g. pressurized separator water and oil samples).

Year 2+ costs for emission sources that require a survey (e.g. components, pneumatic devices), are assumed to be 15% of the Year 1 costs based on a Noble average annual operations acquisition and organic growth rate of 15%. Year 2+ costs for emission sources that require annual or quarterly sampling and/or direct measurement are generally assumed to be 90% of Year 1 costs to account for efficiency improvements.

Average sampling + analytical cost per sample are included as applicable. For process sample collection and analysis (e.g. field gas or separator liquids composition), industry budgetary costs typically range from $150 to $250 per sample. The costs presented in Table A.1 are generally consistent with or lower than these guidelines suggesting they could be a low-biased estimate of the true costs.

Table A-1. Data and Methodologies Used to Estimate Emission Estimation Costs for Onshore Production Sources Affected by MRR Subpart W.

Emission Source	% of US GHG Inv.	Noble GHG Inv. CO2e (tonne/yr)	Year 1 Costs ($/tonne CO2e)	Year 2+ Costs ($/tonne CO2e)	Notes
Well Venting for Liquids Unloading [98.233(f)]	24.3%	89,727	$10.67	$8.56	Must calculate average flowrate per minute for each unique tubing diameter and producing horizon/formation combination in each producing field (Method 1) and apply this flowrate to unloadings from similar wells. Method 2 requires, for each well venting, determine well shut in pressure and duration (in addition to well dimensions). This estimate is for Method 1 because pressure measurements for every event for Method 2 would be prohibitively expensive. For each unique tubing diameter and producing horizon/formation combination assume 4 hours to conduct measurement (set up meter & drive time). Assume 15 minutes to document duration (start and stop) of each event. Approximately 29,000 events per year - about 90% of costs from tracking duration of each event and only about 10% from measurements. It is anticipated that recently commenced project to install automated plunger systems will reduce number of events, emissions, and associated tracking and reporting costs.
Associated Gas Venting and Flaring [§98.233(m)]	12.2%	153,531	$1.64	$1.40	For Noble GHG Inventory includes both vented and flared associated gas. Costs based on collecting annual pressurized oil samples for GOR analysis from 1,319 oil wells that either vent or flare associated gas. 98.233(m)(1) states "Determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared" Assume can collect 8 pressurized samples per day in these areas. Average cost per sample about $175 (may be biased slightly low). Oil production must be tracked.
Gas Well Venting During Unconventional Well Completions and Workovers [98.233(g)]	11.6%	268,852	$0.55	$0.40	For one well completion in each gas producing field and for one well workover in each gas producing field, measure gas flow rate by installing a meter or pressure drop across choke. Use this flow rate EF for all other wells in field. Track duration of all well completions and workovers. For Noble in 2008, about 33% of gas from well completions and workovers is vented and 67% flared. Costs based on measuring choke pressure drop (Calculation methodology 2) – assume 4 hours per event (set up P gauge and travel time) and about 50 producing fields.. Assume 15 minutes to document duration (start and stop) of each event and about 3,400 total events per year. Year 2+ costs based on every other year testing.

Gas-Fired Reciprocating IC Engines (Combustion)	11.3%	211,988	$1.62	$1.19	Engine fuel use calculated from engine load, BSFC, and operating hours. Engine load for compressor drivers determined from control panel parameters (compressor P, T) and compressor manufacturer software. Engine data collected quarterly (15 minutes per event) and 0.5 hours/yr to calculate engine load + 0.5 hours per engine Year 1 to record & document engine data and set up data logs (make, model, etc). 900 ICEs in inventory.
External Combustion: Heaters, boilers	8.4%	265,864	$3.72	$2.12	Fuel consumption estimate based on burner rating, and estimated annual operating hours (e.g. estimate of months operating and percent time firing). Heater/separator data collected quarterly (15 minutes per event) + 0.5 hours per engine Year 1 to record & document equipment data and set up data logs (make, model, burner, rating, etc) . 6050 units in inventory.
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	6.9%	256,723	$1.30	$0.19	Need to survey all wells and document high-bleed devices by make and model. First Year costs based on surveying 10,237 wells and 0.3 hours per well including travel, data organization, etc. Assumed that survey of high-bleed pneumatics, low-bleed pneumatics, and components are done simultaneously. For subsequent years assume 15% new wells.
Portable Combustion Sources (Drill Rigs) [§98.233(z)]	6.6%		-	-	This emission source was not included in Noble Energy GHG inventory, drilling companies have operational control.
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]	3.9%	87,423	$2.59	$0.37	Need to survey all wells and document low-bleed devices by make and model. First Year costs based on surveying 10,237 wells and 0.2 hours per well including travel, data organization, etc. Assumed that survey of high-bleed pneumatics, low-bleed pneumatics, and components are done simultaneously. For subsequent years assume 15% new wells.
Dehydrator (glycol) Vent stacks [98.233(e)]	3.1%	6,796	$11.92	$10.39	Costs based on 60 glycol dehys in Noble Inventory. Need to collect and analyze natural gas samples & dehy parameters (2.5 hours per dehy) and run GLYCalc and document data (1.5 hours per dehy)
Components [§98.233(r)]	3.0%	99,081	$16.88	$2.41	Need to survey all wells and count components on all equipment. First Year costs based on surveying 10,237 wells and 1.5 hours per well including travel, data organization, etc. Assumed that survey of high-bleed pneumatics, low-bleed pneumatics, and components are done simultaneously. For subsequent years assume 15% new wells.

Produced Water Dissolved CO2 [§98.233(y)]	2.7%	103,529	$23.26	$19.90	Quarterly sampling and analysis required for post-separator water for CO_2. Dissolved CO2 not determined for Noble GHG inventory so estimate based on GOR for CO_2 in water estimated to be 12 scf/bbl based on average separator pressure of 85 psi and charts prepared by Kansas Geological Survey. Produced water volume of 131 MMbbls from Noble 2008 GHG inventory. Assume can collect 8 pressurized samples per day per technician (prep, travel, sampling, sample custody and shipping). 5,893 separators in inventory. These costs are shared with sampling required for HC tanks dissolved CO2 samples; and also only based on 3 of 4 quarterly samples because one sample already collected for storage tanks flash gas samples (for E&P Tanks) . Costs would be higher without these shared labor costs. Estimated sampling + analytical cost per sample ≈ $125 (lower than normal range).
Production Storage Tanks [98.233(j)]	2.2%	210,643	$18.18	$15.56	For Noble GHG Inventory, about 22% of gas is vented, 69% flared, and 9% recovered by a VRU. Costs based on collecting annual pressurized oil and water samples from 5,893 separators. Also need to collect a tank sample of sales oil for API gravity and Reid vapor pressure analysis. Average cost per sample about $200. If only collect oil or water sample then cost per sample would increase. Assume can collect all three (two pressurized) samples from 6 separators/tanks per day. Not sure what software used to estimate emissions from Produced water tanks.
Gathering Pipeline Fugitives [§98.233(r)]	1.6%	23,997	$23.23	$3.31	First Year costs based on surveying pipelines ("flowlines" and "intra-facility gathering lines" per 98.230(a)(2)) associated with 10,237 wells and 0.5 hours per well including travel, data organization, etc. Requires person familiar with Noble operations and pipelines. For subsequent years assume 15% of first year costs based on expansion (new wells), acquisitions, divestitures, and modifications. This estimate could change depending on how gathering pipelines are defined; i.e. are high pressure "flowlines" associated with gas wells considered gathering pipelines?
Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	0.7%	8,425	$42.66	$24.43	Annual measurement requirements are vented gas flowrate from rod packing, unit isolation valves, and blowdown valve in three operating modes: Operating, Standby pressurized, and Not operating, pressurized. Assume can test average of 2.5 compressors per day in three modes (50% of tests three per day, 50% of tests two per day). Operator required to change compressor operating mode for testing. Purchase of six hi-flow samplers. Annual operating hours in each mode must be tracked/estimated. 145 compressors in inventory

Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]	0.7%		-	-	This emission source was not included in Noble Energy GHG inventory. Cost to report these emissions expected to be very low because activity data are available from production reports and emissions based on population EF.
Natural Gas driven pneumatic pumps [98.233(c)]	0.6%	85,167	$1.45	$0.54	First Year costs based on surveying 1,514 devices and 0.5 hours to survey each device (get make and model, service, scf/gal data, set up data log) and 0.25 hours to collect liquid used data. For subsequent years assume 15% new devices (based on expansion (new wells), acquisitions, divestitures, and modifications)and must be surveyed by operators with same liquid use data collection requirements for all pumps
Centrifugal Compressor Wet Seal Oil Degassing Vent [§98.233(o)]	0.1%	0	-	-	No Centrifugal Compressors in Noble inventory
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	0.1%	1,437	$48.66	$6.62	Measurement requirements are metered flow of pre- and post-AGR gas, and quarterly sampling and analysis of pre- and post-AGR gas for CO2. Year 1 costs include specify, purchase, and install six meters (3 AGRs) and quarterly samples. Year 2+ costs include recalibrate flow meters and quarterly samples. Estimated sampling + analytical cost per sample ≈ $175.
Gas Well Venting During Conventional Well Completions and Workovers [98.233(h)]	0.1%		-	-	For this analysis, assume all completions and workovers are unconventional.
Dehydrator (Desiccant) Vent stacks [98.233(e)]	0.1%	0	-	-	No desiccant dehydrators in Noble inventory
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	0.0%	73	$41,203	$35,262	Quarterly sampling and analysis of post-flash HC storage tank liquids for CO2. Dissolved CO2 not determined for Noble GHG inventory so estimate based on average GOR of 150 scf/bbl, 2% of gas does not flash, and 3.9% of gas is CO2 (based on Watt flash gas analysis). 11.8 MMbbl condensate + oil from Noble 2008 inventory. Assume can collect 8 pressurized samples per day per technician (prep, travel, sampling, sample custody and shipping). 5,893 separators in inventory. These costs are shared with sampling required for water separator for dissolved CO2 samples; and also only based on 3 of 4 quarterly samples because one sample already collected for storage tanks flash gas samples (for E&P Tanks). Costs would be higher without these shared labor costs. Estimated sampling + analytical cost per sample ≈ $150 (low end of normal range).

Flare Stacks [§98.233(n)]	0.0%	15,727	-	-	Flared gas emissions calculated for individual sources (e.g. well completion) are included in the totals.
Well Testing Venting and Flaring [§98.233(l)]	0.0%		-	-	Emissions from this emission source are included in well completion estimates.
EOR Injection Pump Blowdown [§98.233(w)]	0.0%		-	-	This emission source is not included in Noble Energy operations and GHG inventory.
Total			**$8.47**	**$5.88**	A

A. Cost to collect and analyze gas samples included in Total but not included in costs for individual emission sources.

Attachment B – Documentation of Estimated U.S. GHG Emission Inventory and Subpart W Source Contributions for Onshore Petroleum and Natural Gas Production

This attachment describes the data and methods that were used to estimate GHG emissions from onshore petroleum and natural gas production sources affected by Subpart W and Subpart C of the Mandatory Reporting Rule. These data were used to estimate the contribution of each emission source to the total U.S. inventory emissions and consider the relative significance of the source, whether the source should be excluded from the reporting requirements based on its contribution, and/or whether alternative, streamlined emission estimation methods are necessary.

These estimates were primarily based on the industry GHG emissions data presented in the Technical Support Document (TSD) [Docket Document EPA-HQ-OAR-2009-0923-0027], and data gaps were addressed with data from the EPA Natural GasStar Program, the "Draft Onshore Threshold Analysis (Basin)" [Docket Document EPA-HQ-OAR-2009-0923-0015], GHG emissions data collected by Noble Energy for its API Compendium-based GHG inventory, and engineering judgment/analysis.

Table B.1 provides summary information for each affected emission source. As available, activity data, and methane and CO_2 emission estimates are presented. GHG emissions expressed as CO2e and percent of total inventory are presented for each emission source. The last column details the data, methods, and assumptions used to derive the emissions estimate.

Table B-1. Data and Methodologies Used to Estimate 2006 GHG Emissions for Onshore Production Sources Affected by MRR Subpart W.

Emission Source	Activity Data	AD Units	CH4 (MMcf/yr)	CO2 (MMcf/yr)	CO2e (tonne/yr)	% of Inv.	Emission Estimation Notes
Well Venting for Liquids Unloading [98.233(f)]		LP Gas Wells	118,413		47,685,274	24.3%	Gas wells are vented to the atmosphere to expel liquids accumulated in the tubing. 1.) TSD page 85 estimates "the final resulting emissions from gas well venting due to liquid unloading were estimated to be 223 Bcf." From TSD Page 85 - estimate of 223 Bcf methane emissions "does not include emission reductions from control methods such as plunger lifts, plunger lifts with "smart" automation, or other artificial lift techniques. Thus, 223 Bcf is estimate of potential US emissions from unloading operations. 2.) To estimate percent emissions reduction from applying plunger lifts, plunger lifts with "smart" automation, and other artificial lift, associated GasStar documents[1] and Noble operating experience were referenced. GasStar partners report gas savings of 50% and more from installation of plunger systems and application of smart automation to both wells with plungers and wells without plungers (accumulated liquids expelled conventional way but optimizing shut-in period). Noble operators report 90+% reductions in emissions after installation of automated plunder systems. Estimated emissions reduction assumed to be average of these, or about 70%. 3.) To estimate actual emissions, assume that 33%* of conventional wells do not have smart automation and/or plunger lifts, or other artificial lift; that is, 33%* of the estimated potential gas to be vented (223 Bcf) is vented during traditional unloading operations. For the 67%* of wells with smart automation and/or plunger lifts or other artificial lift, assume emissions are reduced by 70%. * This is an assumed value. It is believed that less than 67% of wells have artificial lift to reduce emissions but discussion with industry personnel suggests that artificial lift is preferentially (being) installed on newer, larger wells with highest unloading losses – estimated to correspond to 67% of potential emissions. Additional data are needed to refine this estimate.

Associated Gas Venting and Flaring [§98.233(m)]			51,011	64,735	23,947,622	12.2%	Total volume of natural gas vented and flared in 2006 from DOE.EIA website (129,469 MMcf). http://www.eia.doe.gov/dnav/ng/hist/n9040us2m.htm. Assume 78.8% CH4, and 50% of emissions flared. Assume 100% combustion efficiency for flare and assume 1 mole C/mole gas to simplify estimation.
Gas-Fired Reciprocating IC Engines (Combustion)	46,356,000,000	hp-hr			22,141,851	11.3%	From EPA-HQ-OAR-2009-0923-0015 pg 1496 - 1498, gas engines activity data of 46,356,000,000 hp-hr for 2006. Assuming BSFC of 9,000 Btu/hp-hr and using Subpart C GHG emission factors (53.02 kg CO_2/MMBtu, 0.001 kg CH_4/MMBtu, and 0.0001 kg N_2O/MMBtu) annual emissions from gas-fired engines were calculated.
External Combustion: Heaters, boilers					16,428,018	8.4%	Based on ratio of external combustion/internal combustion GHG emissions from Noble 2008 inventory (1.25), ratio of US Inventory External Combustion/Internal Combustion equipment counts = (Seps+Heaters+Dehys)/Comp (16.7), ratio of Noble Inventory Internal Combustion/External Combustion equipment counts = Comp/(Seps+Heaters+Dehys) (0.035), and US Inventory Gas-Fired Reciprocating IC Engines GHG Emissions. Noble Energy has a different ratio of internal-to-external combustion devices than the US inventory.
Gas Well Venting During Unconventional Well Completions [98.233(g)]			33,490	42,500	15,722,159	8.0%	Unconventional wells means gas well in producing fields that employ hydraulic fracturing to enhance gas production volumes. Assume that 50% of unconventional well completion volume is vented and 50% is flared (total = 85 Bcf of natural gas, assume 78.8% methane). Total emissions from Subpart W TSD page 82. Assume 100% combustion efficiency for flare and assume 1 mole C/mole gas to simplify estimation.
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	396,920	controllers	33,448		13,469,378	6.9%	Control devices powered by pressurized natural gas and used for maintaining a process condition. Vents (bleeds) to the atmosphere at a rate in excess of six scf/hr. From Noble Energy 2008 GHG inventory pneumatic devices population, about 15% are hi-bleed and 85% are lo-bleed. Hi-bleed EF from GRI/EPA Volume 12 (654 scf NG/day) and Lo-Bleed EF from Sub W (2.75 scf NG/hr). Based on ratio of population % * EFs, about 63.6% of emissions from hi-bleed devices. Total emissions may be biased high due to EF that is basis for total; (i.e. percent of pneumatics that are high/continuous bleed has decreased since the EF was developed).

Portable Combustion Sources [§98.233(z)]					12,874,647	6.6%	This estimate is for GHG emissions from drilling rigs, the predominate portable combustion emission source. Refer to Attachment B.1.
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]			19,143		7,708,890	3.9%	Control devices powered by pressurized natural gas and used for maintaining a process condition. Vents (bleeds) to the atmosphere at a rate less than or equal to six scf/hr. From Noble Energy 2008 GHG inventory pneumatic devices population, about 15% are hi-bleed and 85% are lo-bleed. Hi-bleed EF from GRI/EPA Volume 12 (654 scf NG/day) and Lo-Bleed EF from Sub W (2.75 scf NG/hr). Based on ratio of population % * EFs, about 63.6% of emissions from hi-bleed devices. Total emissions may be biased high due to EF that is basis for total; (i.e. percent of pneumatics that are high/continuous bleed has decreased since the EF was developed).
Gas Well Venting During Unconventional Well Workers [98.233(g]			14,972	19,000	7,028,730	3.6%	Unconventional wells means gas well in producing fields that employ hydraulic fracturing to enhance gas production volumes. Assume that 50% of unconventional well workovers volume is vented and 50% is flared (total = 38 Bcf of natural gas, assume 78.8% methane). Total emissions from Subpart W TSD page 82. Assume 100% combustion efficiency for flare and assume 1 mole C/mole gas to simplify estimation.
Dehydrator (glycol) Vent stacks [98.233(e)]			15,229		6,132,597	3.1%	Dehydrator vent stack emissions means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps. Emissions from Kimray Pump + Dehy vent. Emissions data from Subpart W TSD page 73.
Components [§98.233(r)]			14,830		5,991,473	3.0%	Valves, connectors, OELs, PRVs, vents, compressor starter gas pumps, flanges, and other fugitive sources (such as instruments, loading arms, pressure relief valves, grease fittings, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services). Emissions based on data from Subpart W TSD page 73. Sum of fugitive emissions from gas wells, separators, heaters, dehydrators, meters/piping, and large reciprocating compressor stations.

Produced Water Dissolved CO2 [§98.233(y)]	8,484,000,000			101,808	5,355,422	2.7%	CO_2 retained in produced water immediately downstream of the HC/water separator. Carbon dioxide solubility in water decreases with temperature, increases with pressure, and increases with pH (more soluble in alkaline solutions). US 2006 inventory for produced water based on oil + condensate production and 6 bbl water/bbl oil [Sullivan et al][1] -> 8,484,000,000 bbls water = 6 bbl water/bbl oil * (56,000,000+1,358,000,000) bbl oil. Conservative estimate that does not consider produced water reinjected into formation without reaching atmospheric pressure. GOR for CO_2 in water estimated to be 12 scf/bbl based on average separator pressure of 85 psi and charts prepared by Kansas Geological Survey.[2] These emissions would be estimated by E&P Tank simulations.
Production Storage Tanks [98.233(j)]	56,000,000 bbls (condensate) and 1,358,000,000 bbls (oil)	bbl condensate/yr			4,392,542	2.2%	Atmospheric pressure storage tanks receiving produced liquids from petroleum and natural gas production. Based on sum of condensate tanks w/out control devices and condensate tanks with control devices, and oil tanks w/out control devices and oil tanks with control devices. Total emissions from condensate tanks from Subpart W TSD page 73; assuming 95% control efficiency, and ignoring flare CO2 emissions, these emissions correspond to condensate GOR of 110 scf CH4/bbl and about 80% of emissions being controlled. For oil, annual production of 1,358,000,000 bbls (from EPA-HQ-OAR-2009-0923-0015 pg 1496 - 1498) and assume GOR of 10 scf CH_4/bbl and GOR of 30 scf NG/bbl, 50% of tanks controlled, 95% control efficiency, and for flare combustion assume 100% combustion efficiency and 2.5 mole C/mole gas (higher C content than Field Gas).
Gathering Pipeline Fugitives [§98.233(r)]	392,624	miles	7,616		3,066,891	1.6%	Based on Subpart W emission factor of 2.81 scf NG/mile-hr and 78.8% CH4 in gas. Activity data (392,624 miles) from Subpart W TSD page 73. CO2e slightly lower than reported in table on TSD page 73.

Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	28,591		3,535		1,423,382	0.7%	Reciprocating compressor rod packing means - a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere. When units are pressurized, closed blowdown valve leaks can be a large emission source. When compressor is offline/depressurized, gas leaks from pipeline through unit isolation valves can leak to atmosphere thru open blowdown and/or other valves. Emissions data from TSD page 73. Assume 100% of small compressors in 2006 US inventory are reciprocating (28,490) and that 90% of large compressors in 2006 US inventory are reciprocating (90% of 112) (from EPA-HQ-OAR-2009-0923-0015 pg 1496 - 1498). Conservatively assume that all fugitive emissions from 2006 Inventory are from the rod packing, and blowdown and isolation valves.
Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]			3,478		1,400,495	0.7%	Emissions data from TSD page 73, based on Powder River + Black Warrior basins.
Natural Gas driven pneumatic pump [98.233(c)]	30,006	CIPs	2,823		1,136,867	0.6%	Pump that uses pressurized NG to move a piston or diaphragm and pump liquids. Emissions data for CIPs from Subpart W TSD page 73.
Centrifugal Compressor Wet Seal Oil Degassing Vent [§98.233(o)]	11				187,000	0.1%	Centrifugal compressor wet seal degassing venting emissions- means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. Assume 10% of large compressors in 2006 US inventory for E&P (112 total - EPA-HQ-OAR-2009-0923-0015 pg 1496 - 1498)) are centrifugal and conservatively assume all are equipped with wet seals (over-estimates emissions). Assume that emissions from the wet compressor seals = 100 scf/min (approx 17,000 tonne CO2e/yr) - from GasStar Lessons Learned "Replacing Wet Seals with Dry Seals in Centrifugal Compressors". Centrifugal compressors are not frequently employed for oil and gas production because reciprocating compressors have partial load operating advantages. Noble does not own or operate centrifugal compressors and Noble is not aware of any centrifugal compressors used in onshore oil and natural gas production.

							In addition, the prevalence and use of wet seals for centrifugal compressors have steadily decreased since wet seals were identified as a gas emission source; thus, it is expected that the few centrifugal compressors used for onshore production would primarily be equipped with dry seals.
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	141,210	MMcf/yr		2,824	148,562	0.1%	CO2 is separated from natural gas by an acid gas removal (AGR) system. Assume 0.6% of US gas production is treated by Production Sector AGRs. In 2008 Noble Energy treated 0.6% of produced gas with AGRs. Total 2006 US gross production of 23,535,018 MMcf from DOE/EIA website. Assume 2% of gas is removed as CO2. AGRs primarily in processing sector and not prevalent in production.
Gas Well Venting During Conventional Well Completions [98.233(h)]			276	350	129,477	0.1%	Conventional wells means gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas. Assume that 50% of conventional well completion volume is vented and 50% is flared (total = 0.7 Bcf natural gas, assume 78.8% methane). Emissions data from Subpart W TSD page 82. Assume 100% combustion efficiency for flare and assume 1 mole C/mole gas to simplify estimation.
Dehydrator (Desiccant) Vent stacks [98.233(e)]			305		122,652	0.1%	Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Assume emissions from desiccant dehydrators = 2% of glycol dehydrator emissions (based on GasStar document "Replacing Glycol Dehydrators with Desiccant Dehydrators" http://www.epa.gov/gasstar/documents/ll_desde.pdf) and that desiccant dehydrators treat the same volume of gas as glycol dehydrators.
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	1,414,000,000	bbl condensate/yr		165	8,703	0.0%	CO_2 retained in hydrocarbon liquids after flashing from storage tanks at STP. From API Compendium Page E-4. "Once live crude reaches atmospheric pressure and the volatile CH4/CO2 has flashed off (as described in Section 5.4.1), the crude is considered “weathered” and the crude oil vapors contain very little, if any, CH4 or CO2." The API Compendium and Subpart W docket do not have data or methods to estimate emissions that would result if all CO_2 in HC liquids was emitted. This estimate is based on average GOR of 150 scf/bbl, 2% of gas does not flash, and 3.9% of gas is CO_2 (based on flash gas analysis from largest

							Noble Energy field). Total HC liquids = 56 MMbbl condensate + 1,358 MMBbbl oil (from EPA-HQ-OAR-2009-0923-0015 pg 1496 - 1498).
Gas Well Venting During Conventional Well Workovers [98.233(h]			14	18	6,659	0.0%	Conventional wells mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas. Assume that 50% of conventional well workovers volume is vented and 50% is flared (total = 0.036 Bcf natural gas, assume 78.8% methane). Emissions data from Subpart W TSD page 82. Assume 100% combustion efficiency for flare and assume 1 mole C/mole gas to simplify estimation.
EOR Injection Pump Blowdown [§98.233(w)]					0	<0.1%	EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil. Subpart W TSD page 88 listed parameters used to estimate emissions "It is assumed that the pump and pipeline vent gas equivalent to their volume once a year during blowdown operations." The number of supercritical pumps required per field was estimated by assuming that the EOR operations use pumps with 600 hp with a throughput of 40 Mcf/day." From EPA-HQ-OAR-2009-0923-0015 page 1512, volume of pump and associated piping is 20 cf. From EPA-HQ-OAR-2009-0923-0015 page 1511, density of critical CO2 is 0.464 tonne/m3; estimate 0.263 tonne CO2/pump-yr. Estimated number of pumps required to be 1% of inventory is about 5,000,000 - based on these data, therefore, this is an insignificant source.
Flare Stacks [§98.233(n)]					0	0.0%	Emissions from flares are included in the estimated emissions from specific emission sources.
Well Testing Venting and Flaring [§98.233(l)]			0		0	0.0%	Assume emissions from this emission source and would be included in well completion estimates.
TOTAL			**318,581**		**196,5097,290**	**100.0%**	

[1] http://www.epa.gov/gasstar/documents/partnerupdate.pdf, http://www.epa.gov/gasstar/documents/desaulniers.pdf
[2] http://www.unm.edu/~cstp/Reports/H2O_Session_4/4-5_Sullivan.pdf
[3] http://www.kgs.ku.edu/PRS/publication/2003/ofr2003-33/P1-05.html

Attachment B.1 Portable Combustion Equipment (Drilling Rigs)

Docket document EPA-HQ-OAR-2009-0923-0015 (Draft Onshore Production Threshold Analysis (Basin)) lists combustion emission estimates for dehydrators and drilling rigs. The estimated drilling rigs emissions are almost three orders of magnitude more than the dehydrator emissions; thus, the focus of this portable combustion equipment emissions analysis is drilling rigs. Page 1497 of EPA-HQ-OAR-2009-0923-0015 provides the following information to estimate drilling rig annual GHG emissions:

Table B1-1. Docket Estimate of 2006 Drilling Rigs GHG Emissions.

Drilling Engine:	1,500 HP
Emissions per engine:	462 tonne CO2e/rig engine-well
Natural Gas Combustion EF	0.0560 tonne CO2e/10^6 Btu
Heat content	1020 Btu/ cf
Operation Duration	90 Days
# of gas wells drilled 2006	35,600 wells
Total Emissions	32,878,315 tonne CO2e

The analysis assumes two engines per rig (Subpart W TSD page 87) or 932 tonne CO2e/well.

462 tonne CO2e/rig engine for a 1,500 hp engine equates to about 26 days of engine operation;

$$611\left(\frac{hrs}{well}\right) = 462\left(\frac{tonne\,CO2e}{rig\ engine-well}\right)*\frac{1}{0.056}\left(\frac{MMBtu}{tonne\,CO2e}\right)*10^\wedge 6\left(\frac{Btu}{MMBtu}\right)*\frac{1}{1{,}500}\left(\frac{rig-engine}{hp}\right)*\frac{1}{9{,}000}\left(\frac{hp-hr}{Btu}\right)$$

for a 90 day Operation Duration, this equates to engine operation about 30% of the time assuming the engines are operating at 100% load.

However, the data presented in the table above are not consistent with well drilling data for 2006 compiled by the DOE Energy Information Administration (EIA)[5] [6]

U.S. Onshore Crude Oil and Natural Gas Rotary Rigs in Operation (Number of Elements)	1,558 (monthly average)
U.S. Natural Gas Exploratory and Developmental Wells Drilled (Number of Elements)	32,877
U.S. Crude Oil Exploratory and Developmental Wells Drilled (Number of Elements)	13,288
U.S. Dry Exploratory and Developmental Wells Drilled (Number of Elements)	5,177
Total Wells Drilled	51,342

[5] http://www.eia.doe.gov/dnav/ng/ng_enr_drill_s1_m.htm
[6] http://www.eia.doe.gov/dnav/ng/ng_enr_wellend_s1_m.htm

$$32.9\left(\frac{wells}{rig\text{ - }yr}\right) = 51{,}342\left(\frac{wells}{yr}\right) * \frac{1}{1{,}558}\left(\frac{1}{rigs}\right) \qquad \text{Eqn. B1-1}$$

$$266\left(\frac{rig\text{ - }hrs}{well}\right) = 365\left(\frac{days}{yr}\right) * \frac{1}{32.9}\left(\frac{rig\text{ - }yr}{wells}\right) * 24\left(\frac{hr}{day}\right) \qquad \text{Eqn. B1-2}$$

The average of 266 hours (about 11 days) for each well is much less than the 90 day Operation Duration and as well as the 26 days of operation for each engine. Thus, the assumptions used to calculate the drilling rig emissions of 32,878,315 tonne CO2e/yr presented in the docket (refer to Table B1-1) do not appear to be valid. To provide a more reliable estimate of GHG emissions from drilling rigs, 2006 fuel use data for about 4,700 spuds (i.e. drilling operations) collected by the Western Regional Air Partnership (WRAP) for four basins in Colorado, Utah, and New Mexico. These data represent about 10% of the wells drilled in 2006 and were extrapolated to estimate US GHG emissions for onshore production drill rigs in 2006 as follows.

Table B1-2 summarizes the WRAP III drilling rigs data and the calculations used to estimate the associated diesel fuel use.

Table B1-2. Estimated 2006 Drilling Rigs Diesel Fuel Use in Four Basins.

Basin[A]	Spuds[A]	tons SO2[A]	ppm S in diesel[A]	Percent S -> PM[A]	ton S/ ton SO2	ton Fuel/ ton S	lb/ton	gal/lb[B]	gal fuel
	A	B	C	D	E	F = 10^6/ (C*(1-D))	G	H = 1/7.07	I = B*E*F*G*H
Denver-Julesburg	1,500	58.8	500	2.20%	0.5005	2,045	2,000	0.141	17,023,763
Piceance	1,186	242.1	500	2.20%	0.5005	2,045	2,000	0.141	70,092,739
Unita	1,069	361.6	2,400	2.20%	0.5005	426	2,000	0.141	21,810,490
South San Juan	919	80.5	2,400	2.20%	0.5005	426	2,000	0.141	4,855,488
Total	**4,674**								**113,782,481**

A. Western Regional Air Partnership (WRAP) Phase III inventory project. http://www.wrapair.org/forums/ogwg/PhaseIII_Inventory.html
B. Diesel fuel density of 7.07 lb/gal. API Compendium DRAFT Version 3, Table 3-8.

Equation B1-3 calculates estimated drilling rigs GHG emissions for the four basins in 2006.

$$1{,}172{,}064(tonne\ CO2e) = 113{,}782{,}481(gal\ diesel) * \frac{1}{42}\left(\frac{bbl}{gal}\right) * 5.83\left(\frac{MMBtu}{bbl}\right) * \frac{1}{1{,}000}\left(\frac{tonne}{kg}\right) *$$
$$\left(73.92\left(\frac{kg\,CO2}{MMBtu}\right) + 21\left(\frac{kg\,CO2e}{kg\,CH4}\right) * 0.003\left(\frac{kg\,CH4}{MMBtu}\right) * 310\left(\frac{kg\,CO2e}{kg\,N2O}\right) * 0.0006\left(\frac{kg\,CO2e}{kg\,N2O}\right)\right) \qquad \text{Eqn. B1-3}$$

Where:

5.83 - HHV of diesel fuel [API Compendium DRAFT Version 3, Table 3-8];

73.92 - Subpart W CO_2 emission factor for diesel fuel combustion;

21 - Global warming potential for methane;

0.003 - Subpart W CH_4 emission factor for diesel fuel combustion;

310 - Global warming potential for nitrous oxide;

0.0006 - Subpart W N_2O emission factor for diesel fuel combustion;

Equation B1-4 calculates estimated drilling rigs GHG emissions for the US inventory in 2006 based on the average GHG emissions per well drilled in the four basins.

$$12{,}874{,}647(tonne\ CO2e) = \frac{1{,}172{,}064}{4{,}674}\left(\frac{tonne\ CO2e}{spuds}\right) * 51{,}342(spuds) \qquad \text{Eqn. B1-4}$$

Where:

1,172,064 - estimated GHG emissions from drilling rigs in the four basins

51,342 - total number of wells drilled (“spuds”) in U.S. in 2006; and

4,674 - total number of wells drilled (“spuds”) in four basins in 2006.

Attachment C. Safety Issues Associated with GHG Reporting Rule Data Collection for Onshore Petroleum and Natural Gas Production

Test methods/procedures and job hazards assessments need to be completed to evaluate safe monitoring and measurement from Subpart W sources. EPA has not adequately contemplated the costs or time required to implement source measurements further discussed below. Noble requests that any source deemed unsafe to measure be placed on a list and accompanied with an explanation of the specific safety concerns. In the absence of measured data, Noble suggests using published emission factors or engineering estimates to be used in lieu of unsafe to monitor sources. Alternatively EPA should provide a method or procedure that allows the safe access and measurement of such sources.

Reciprocating Compressor Rod Packing Vents

Safety is a very significant issue when attempting to collect measurements from roofline vents at onshore natural gas processing facilities or gathering compressor stations. Safe access to and sample collection from leaking reciprocating compressor rod packing vents are mandatory. At these existing facilities, the majority of vents are routed outside the compressor building and elevated above the roof line to disperse potentially flammable gas vapor. In addition to gaining safe access to the elevated vent source, these vents are frequently manifolded with other vents or adjacent to blowdown vents that may automatically discharge to relieve pressure. Any measurement requirement that results in placing test personnel in a potentially dangerous environment is deemed unacceptable.

Resolution would likely require modifications to provide vent access from a safer location. However, line accessibility may not be readily available as the facilities were not constructed considering access. Engineering evaluations and analysis would be necessary to identify possible sample port locations. Due to the proposed schedule, this would put operators at risk of failing to comply with the annual survey requirement, or placing test personnel would be exposed to an immediate danger defying safety procedures. Therefore, additional time is required to implement the vent measurement program so that modifications can be made to accommodate measurement from a safer location than the vent exhaust from these elevated sources.

The majority of building roofline vents would be deemed inaccessible under conventional LDAR programs, as such components would be considered unsafe-to-monitor (UTM) or difficult-to-monitor (DTM) in a typical LDAR program (i.e., components that cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface). In addition, a manlift is typically required to gain access over high pressure yard piping further complicating access and safety concerns for elevated vents. Under a typical LDAR program, monitoring can be deferred due to unsafe or difficult-to-monitor components. In response, the facility must maintain documentation that explains the conditions under which the components become safe to monitor or no longer difficult to monitor. For vent lines at most gathering compressor stations, typical conditions under which these vents would be "safe" would preclude normal engine operations or pressurized scenarios where the potential for a vented release is possible.

Leak detection and repair (LDAR) programs are required as part of 40 Code of Federal Regulations (CFR) Part 60 (NSPS), 40 CFR 61 (NESHAP), 40 CFR 63 (MACT), and 40 CFR

264 (Hazardous Waste Handling). LDAR requirements provide allowances for identification and explanation for any equipment that is:

- unsafe to monitor (UTM) – Exposing test personnel to an immediate danger as a consequence of monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, high pressure piping, proximity to heated, sharp, or rotating equipment, or would risk damage to equipment.
- difficult to monitor (DTM) – obstructed access (e.g. insulated), elevated access > 2 meters required, limited access to component
- inaccessible - Obstructed by equipment, piping, or insulation that prevents access to the connector by a monitor probe; Buried or confined space entry prohibits access to measurements.

DTM and UTM provisions for accommodating safety related concerns or measurement or monitoring access need be considered and allowances for estimating these sources provided.

<u>Pressurized Vessel Liquid Sample Collection</u>

Care must be taken to safely obtain liquid samples from pressurized vessels. These pressure vessels have a wide range of operating temperatures and pressures. When mishandled, samples taken from high-pressure systems can cause serious injury, or even death. Even a small pinhole in a high-pressure line can cause serious injury. Whenever a sample is drawn, every precaution necessary must be taken to ensure the safety not only of the sample collector, but also of those working around the system. As with all high-pressure sampling systems, appropriate safety precautions must be followed. Sampling procedures and taps must be properly sighted and installed to reduce safety concerns. The cost and burden for safely accessing these samples has not been considered or addressed.

<u>Other Related Safety Concerns</u>

Safety training for fall protection and hydrogen sulfide (H_2S) or respirator certification will be required for most test personnel to allow safe measurement from vents and component population counts. Unlike the downstream sector, field natural gas may contain higher levels of hydrogen sulfide (highly toxic and flammable gas) and higher quantities of nitrogen or carbon dioxide (potential asphyxiants). Potential exposure to these high concentrations of these compounds requires training, safety awareness, proper certifications, and field/facility overviews prior to conducting any measurement activities. In addition, hot work permits are required for any equipment or instrument that is not intrinsically safe. This permit adds to the cost and implementation burdens and has not been considered by EPA in the cost analysis.