Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Supplemental Rule (GHG Reporting)

Final Report

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INTRODUCTION AND BACKGROUND

1.1 Background

On December 26, 2007, President Bush signed the FY2008 Consolidated Appropriations Amendment, which authorized funding for the U.S. Environmental Protection Agency (EPA) to develop and publish a draft rule on an accelerated schedule:

> [N]ot less than $3,500,000 shall be provided for activities to develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to require mandatory reporting of GHG emissions above appropriate threshold in all segments of the economy.

The accompanying explanatory text stated that EPA shall “use its existing authority under the Clean Air Act” to develop a mandatory GHG reporting rule.

> The agency is further directed to include in its rule reporting of emission resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate. The Administrator shall determine appropriate thresholds of emissions above which reporting is required, and how frequently reports shall be submitted to EPA. The Administrator shall have discretion to use existing reporting requirements for electric generating units under Section 821 of the Clean Air Act.

EPA signed the final Mandatory Reporting Rule (final MRR) on September 22, 2009, which was published in the October 30, 2009 Federal Register (74 FR 56260). The final MRR did not include Subpart W, Petroleum and Natural Gas Systems due to the extensive number of comments received on the April 10, 2009, proposal (74 FR 16448). Instead, EPA revised the Subpart W proposal based on its review of the comments and updated information about monitoring techniques. As a result, EPA has issued a supplemental proposed rulemaking today that would add Subpart W to the final MRR and collect emissions data from two additional segments in the petroleum and natural gas source category.

This economic impact analysis assesses the costs and benefits of the Subpart W supplemental proposed rulemaking and highlights differences from the original proposal. For example, the supplemental proposed rulemaking incorporates additional methodologies at lower costs per metric ton for the industry segments compared to the original proposal; the supplemental proposal also includes the key onshore production segment as well as natural gas distribution.

The methodology proposed for Subpart W under the original MRR involved 100 percent measurement for the six segments covered (offshore production, onshore gas processing, transmission, underground storage, LNG storage and LNG import & export). In contrast, today's supplemental rulemaking proposes hybrid methodologies to quantify GHG emissions from eight segments in the petroleum and natural gas systems subpart (the original six plus onshore production and natural gas distribution). The proposed hybrid methodologies would use limited direct measurement, e.g., only in areas where emissions are known to be significant and insufficient reliable data are available to develop emissions factors. The bulk of emissions will be quantified using engineering calculation estimates based on actual facility or field data, and the use of leak detection and "leaker" factors[1]. There are also some sources that would use population based factors—often referred to as default factors—primarily for inaccessible sources or relatively small fugitive sources. Consistent with the supplemental proposed rulemaking and Technical Support Document (TSD) (EPA-HQ-OAR-2009-0923), the economic analysis uses population based factors. In addition, EPA is recommending use of the MMS Gulfwide Offshore Activity Data System (GOADS) process for collecting data from offshore production platforms. This leverages an existing GHG data collection process to minimize burden.

Overall, the hybrid methodology case results in a significant reduction in the compliance cost per metric ton of fugitive and vented GHG emissions reporting relative to the original proposal. For the six original segments, fugitive and vented emissions costs decline from \$0.36/metric ton CO_2e in the original proposal to \$0.10/tonne CO_2e in the supplemental proposed rulemaking, based on average "subsequent year" costs.[2] The cost per metric ton for onshore production is \$0.06/metric ton CO_2e and for natural gas distribution reporters is \$0.04/metric ton CO_2e. Overall cost for the entire petroleum and natural gas source category will be \$21.5 million, or an average of \$0.08/metric ton CO_2e for about 272 million metric tons CO_2e process emissions.

[1] Leaker factors are factors developed by actual measurement of leaks from a large population of common fugitive or vented sources; the emissions quantification requires actual detection of a leak before application of a factor. This provides a truer assessment of actual emissions than "population" emissions factors which are based on simple population count (which assume a percentage of leaking components, hence they are only "potential" emissions).

[2] Unless otherwise specified, this document reports all costs in 2006 dollars and the emissions as CO_2e using a 100-year global warming potential from the IPCC. Also, subsequent year costs are the average of costs subsequent to year one costs, and thereby represent a "steady-state" time period.

The hybrid monitoring case also accounts for the cost to report combustion emissions because some entities that equal or exceed the Subpart W threshold for fugitive and vented emissions would need to report combustion emissions under Subpart C of the final MRR. In those cases, the entities would not have triggered the Subpart C reporting threshold in the absence of Subpart W. However, entities that meet the emissions threshold under Subpart W are required to report combustion emissions under Subpart C, even if the combustion emissions alone do not exceed the Subpart C threshold. In short, EPA expects the addition of Subpart W to the MRR to result in the reporting of additional combustion emissions under Subpart C. Total combustion emissions reported under Subpart C would total about 158.1 million metric tons CO_2e, and would cost $5.8 million per year, or $0.04/metric ton. Of the 158.1 million metric tons, 79.1 million metric tons CO_2e are the combustion emissions from petroleum and natural gas facilities that would not have reported in the absence of Subpart W. The incremental combustion emissions reporting is $3.9 million per year of the total combustion emissions cost, or $0.05/metric ton.

Year one costs for Subpart W vented and fugitive emissions are significantly higher than the "subsequent year" costs, totaling $56 million for fugitive and vented emissions determination compared to $21.4 million in subsequent years. The higher burden is due to the requirement to install ports in vent lines for compressors and well equipment to enable spot measurement of emissions using devices such as vane anemometers. The installation of ports results in a high first year cost, beyond which the only cost in subsequent years is to physically take spot measurements.

The total cost for Subpart W reporting is therefore significant compared to most other MRR source categories. The alternative of direct measurement (continuous emissions monitoring system, or "CEMS" case) for all Subpart W segments would result in a prohibitive total cost to reporting parties. The cost to simply use default emission factors would be lower, but reliable default emissions factors are not available for many large onshore production sources and large vented sources in other segments. This would make the emissions reported from these emissions sources unreliable and inhibit achievement of the MRR's goal to gather information on actual emissions that could inform future policy.

Finally, the original MRR proposal from April 10, 2009 included both vented and fugitive emissions sources, and collectively defined both sources as "fugitive." EPA received a large number of comments from industry stakeholders and others indicating that this definition created confusion. Hence we are defining vented emissions separately from fugitives in the supplemental proposed rulemaking. For this supplemental rulemaking, emissions from the petroleum and natural gas industry are defined as:

1) vented emissions, which include intentional or designed releases of CH_4 and/or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas) from emissions sources including, but not limited to, open ended lines, gas pneumatic powered valves and pumps, equipment depressuring to the atmosphere and compressor shaft seals;

2) fugitive emissions, which are defined to include those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening; and

3) flare combustion emissions, which include CH_4, CO_2 and N_2O emissions resulting from combustion of gas in flares.

1.2 Role of the Economic Impact Analysis in the Rulemaking Process

1.2.1 Legislative Roles

This report analyzes the estimated regulatory economic impacts of the mandatory reporting program that EPA has developed for Subpart W, in accordance with the FY08 Appropriations language, under the authority of Section 114 of the Clean Air Act [CAA]. Section 114 provides EPA broad authority to collect data for the purpose of “carrying out any provision” of the Act (except for a provision of Title II with respect to manufacturers of new motor vehicles or new motor vehicle engines). Section 114(a)[3] of the CAA authorizes the Administrator to, *inter alia*, require certain persons (see below) on a one-time, periodic or continuous basis to keep records, make reports, undertake monitoring, sample emissions, or provide such other information as the Administrator may reasonably require. This information may be required of any person who (i) owns or operates an emission source, (ii) manufactures control or process equipment, (iii) the Administrator believes may have information necessary for the purposes set forth in this section, or (iv) is subject to any requirement of the Act (except for manufacturers subject to certain Title II requirements). The information may be required for the purposes of developing an implementation plan, an emission standard under sections 111,

[3] The joint explanatory statement refers to “Section 821 of the Clean Air Act” but section 821 was part of the 1990 CAA Amendments and was not codified into the CAA itself.

112 or 129[4], determining if any person is in violation of any standard or requirement of an implementation plan or emissions standard, or "carrying out any provision" of the Act (except for a provision of Title II with respect to manufacturers of new motor vehicles or new motor vehicle engines)[5].

The scope of the persons potentially subject to a section 114(a)(1) information request (e.g., a person "who the Administrator believes may have information necessary for the purposes set forth in" section 114(a)) and the reach of the phrase "carrying out any provision" of the Act are quite broad. EPA's authority to request information reaches to a source not subject to the CAA, and may be used for purposes relevant to ***any*** provision of the Act. Thus, for example, utilizing section 114, EPA could gather information relevant to carrying out provisions involving research (e.g., section 103(g)); evaluating and setting standards (e.g., section 111); and endangerment determinations contained in specific provisions of the Act (e.g., 202); as well as other programs.

EPA has recently announced a number of climate change related actions, including:

- Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act (74 FR 18886, April 24, 2009);

- Joint proposed rulemaking with DOT to limit greenhouse gas emissions from light-duty vehicles, "Joint Rulemaking to Establish Vehicle GHG Emissions and CAFÉ Standards," (74 FR 49454, September 28, 2009);

- Reconsideration of the memo entitled "EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program" (73 FR 80300, December 31, 2008); and

- Granting the California Waiver (74 FR 32744, July 9, 2009).

These are all separate actions. Some are related to EPA's response to the U.S. Supreme Court's decision in Massachusetts v. EPA. 127 S.Ct. 1438 (2007), others are EPA actions to address climate change. The MRR and this supplemental proposed rulemaking do not indicate EPA has made any final decisions on these other actions. However, the mandatory GHG reporting

[4] Section 111 of the CAA allows for "standards of performance for new stationary sources," section 112 is for "hazardous Air Pollutants," and section 129 contains provisions for "solid waste combustion."

[5] Although there are exclusions in section 114(a)(1) regarding certain title II requirements applicable to manufacturers of new motor vehicle and motor vehicle engines, section 208 authorizes the gathering of information related to those areas.

program will provide EPA, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions, which could assist in future policy development.

Accurate and timely information on GHG emissions is essential for informing some future climate change policy decisions. Although additional data collection (e.g., for other source categories such as indirect emissions or offsets) will no doubt be required as the development of climate policies evolves, the data collected in this rule will provide useful information for a variety of polices. Furthermore, many existing programs collect this type of information and will continue to do so. Through data collected under this rule, EPA, States and the public will gain a better understanding of the relative emissions of the petroleum and natural gas industry, and the distribution of emissions from individual facilities within different segments of this industry. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions.

The Agency considered a wide range of determining factors when selecting the alternatives for this rule. These included the consideration of costs and benefits, which are essential to making efficient, cost-effective decisions for implementation of these standards. Other important considerations included the language of the Appropriations Act and the accompanying explanatory statement related to source categories; consistency with other CAA or state-level regulatory programs that typically require facility or unit level data; the relative accuracy of different monitoring approaches and the monitoring methods already in use within the petroleum and natural gas industry; and the potential burden placed on small businesses associated with a range of reporting thresholds.

This Economic Impact Analysis is intended to inform the public about the selection criteria for this rule, which include, but are not limited to, the potential costs and benefits that may result when the mandatory reporting program is implemented.

1.2.2 Role of Statutory and Executive Orders

Several statutes and executive orders dictate the manner in which EPA considers rulemaking and apply to any public documentation. The analysis required by these statutes and executive orders is presented in Section 6.

EPA presents this Economic Impact Analysis for Subpart W—Petroleum and Natural Gas Systems—pursuant to Executive Order 12866, the guidelines of Office of Management and

Budget (OMB) Circular A-4, and EPA's Economic Guidelines[6]. These documents present guidelines for EPA to assess the benefits and costs of the selected regulatory option, as well as options that are more stringent or less stringent. Section 4 of the Economic Impact Analysis presents the costs of the supplemental proposed rulemaking; section 5 summarizes the cost-effectiveness analysis of the program. Section 5 also qualitatively describes the benefits of the supplemental proposed rulemaking.

1.2.3 Illustrative Nature of the Analysis

The analysis illustrates the types of costs and benefits that may accrue as a result of the program. The estimates of costs reflect existing production levels in Subpart W for certain petroleum and natural gas systems. Estimates of emissions are based on 2006 data with a number of adjustments to reflect best and most current information from published sources (delineated in the TSD). When the reporting program takes effect, actual patterns of economic activity and emissions may differ from current conditions. However, these data provide estimates of baseline conditions and estimated costs of compliance.

1.3 Overview and Design of the Economic Impact Analysis

This Economic Impact Analysis for Subpart W comprises seven sections. Following this introductory section, Section 2 describes segments affected by Subpart W provisions and reviews existing reporting programs and how they treat comparable petroleum and natural gas systems. Section 3 describes the development of the rule, including control options and analyses of alternative scenarios. Section 4 characterizes baseline conditions and presents engineering estimates of the costs of complying with Subpart W of the rule. Section 5 presents an assessment of the monitoring and reporting costs for the petroleum and natural gas industry, a qualitative examination of uncertainty related to measurement accuracy of monitoring methods prescribed, and an assessment of potential impacts on small entities. Section 5 also presents a brief qualitative examination of potential benefits of the rule. Section 6 provides a discussion of the Agency's compliance with executive orders and other statutes during the development of the rule. Section 7 describes EPA's conclusions and findings.

1.3.1 Baseline and Years of Analysis

Data used for the analysis represent the most recent data available on estimates of GHG emission for the petroleum and natural gas source category, productive capacity, existing emissions monitoring, and reporting activities for this industry. While EPA recognizes that

[6] U.S. Office of Management and Budget. Circular A-4, September 17, 2003: http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf.

economic growth and changes in the structure of the economy over time will likely result in changes in both emissions and costs for those covered by Subpart W, attempting to project these changes would lead to an increased level of uncertainty without conveying comparable improvements in the assessment. Thus, EPA uses data representing essentially current conditions as a proxy for conditions present when the rule takes effect. Such estimates are inherently uncertain because data needed for more precise measurements are not available. The data collected by the rule would greatly enhance future estimates.

1.3.2 Developing the GHG Reporting Rule Considered in This Economic Impact Analysis

In order to ensure a comprehensive consideration of GHG emissions, EPA conducted numerous stakeholder meetings, evaluated over 80 significant and detailed comments (over 1,200 plus pages for Subpart W) and conducted extensive review and analysis of available information on segments and specific sources.

EPA examined existing GHG reporting programs prior to developing the rule. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the rule to see how these programs treat emissions from the petroleum and natural gas industry. One of EPA's goals was to develop a reporting rule for Subpart W units that, to the extent possible and appropriate, is consistent with existing GHG emission estimation and reporting methodologies in order to reduce the burden of reporting for all parties involved. The TSD documents our review of GHG monitoring protocols for each segment identified by Subpart W that is used by federal, state, regional, and international voluntary and mandatory GHG programs, and our review of state mandatory GHG rules and how they treat fugitive emission from the petroleum and natural gas industry.

EPA's overall rulemaking approach began with identification of anthropogenic sources in the U.S. GHG Inventory and Intergovernmental Panel on Climate Change (IPCC). The rule would require reporting of CO_2 and CH_4 fugitive and vented emissions, and combustion-related emissions[7] of CO_2 and CH_4 and N_2O as defined in the rule. The IPCC focuses on CO_2, CH_4 and N_2O for both scientific assessments and emissions inventory purposes because these are long-lived, well-mixed GHGs not controlled by the Montreal Protocol on Substances that Deplete the Ozone Layer. These GHGs are directly emitted by human activities, are reported annually in EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, and are the common focus of the climate change research community.

[7] It must be noted that only flaring emissions are required for reporting under this Subpart of the MRR. All other combustion related emissions are to be reported under Subpart C of the finalized MRR.

EPA then conducted a review of existing methodologies and reporting programs (e.g., California Air Resources Board [CARB], The Climate Registry [TCR], 1605b of the Energy Policy Act). EPA's review of existing reporting programs and measurement methodologies employed by existing federal and state programs is described in Section II of the final MRR Preamble (74 FR 56260, October 30, 2009). A description specific to petroleum and natural gas can be found in Section C of the TSD. EPA used this information to inform its selection of measurement and reporting methods for this supplemental proposed rulemaking.

Once EPA had a complete list of source categories relevant to the United States., the Agency systematically reviewed those source categories against the following criteria to develop the list of source categories included in the proposal:

(1) Include source categories that emit the most significant amounts of GHGs, while also minimizing the number of reporters; and

(2) Include source categories that can be quantified with an appropriate level of accuracy.

Source categories that would be required to report were identified. Sources were then screened by several key criteria, looking at the number of reporters versus the coverage of emissions under various thresholds, relevant and appropriate quantification methodologies, quantification accuracy, and administrative burden. Based on the source level screening activities, possible reporting methodologies for the selected sources were developed. The reporting methodologies identified fall into several categories, including continuous emissions monitoring, calculating emissions based on site-specific information, and calculating emissions based on default emissions factors. In general, for the final MRR, EPA selected a combination of continuous emissions monitoring and calculations based on site-specific information.

For Subpart W, the original rule proposal involved almost exclusive application of detection and direct spot measurement[8] of vented and fugitive emissions for the six segments (offshore production, onshore natural gas processing, transmission, underground storage, LNG storage and LNG import and export facilities). The supplemental proposed rulemaking includes eight segments—the original six plus onshore petroleum and natural gas production and natural gas distribution—and significantly reduces the sources that must be directly quantified. While direct spot measurement is still required to develop site or equipment-specific emissions factors

[8] Direct spot measurement means that the reading is taken only once in the reporting year and through direct measurement using a vane anemometer or similar equipment; the measurement is not "CEMS" as it is not continuous.

for some major sources, much of the emissions quantification is through effective but less burdensome use of engineering estimates and leak detection with use of leaker factors and component population count and population (default) emission factors.

Once the Subpart W segments and methodologies had been identified, EPA evaluated different rule options across the following dimensions:

- Threshold (level of emissions below which entities are not required to report);
  - 1,000 metric tons CO_2e/year;
  - 10,000 metric tons CO_2e/year;
  - 25,000 metric tons CO_2e/year;
  - 100,000 metric tons CO_2e/year;
- Methodology for measuring emissions;
  - Direct spot measurement;
  - Facility-specific calculation methods;
  - Leaker and default emissions factors;

The Agency examined several options for each dimension to identify the selected option for the rule.

The options and alternatives evaluated are described in detail in Section 3. Section 4 details the engineering cost analysis which outlines the monitoring and reporting activities and costs for each source under Subpart W that is required to report.

1.3.2.1 Summary of the Major Changes Since April, 2009 Proposal

EPA received a total of approximately 16,800 public comments on the proposed rulemaking for all subparts. EPA held two public hearings and conducted an unprecedented level of outreach between signature of the proposal and the close of the public comment period. Over 1,200 pages of comments were received specific to the original rule proposal Subpart W. Below are the major changes reflected in the supplemental proposed rulemaking for Subpart W:

- Two additional petroleum and natural gas system segments have been added: onshore production and natural gas distribution. These segments represent the largest (onshore production) and fourth largest (natural gas distribution) segments for fugitive, vented, and flare emissions in the petroleum and natural gas system source category.

- The original rule proposal for Subpart W reflected costs that were about 19 percent of total original rule proposal costs, while emissions covered were only 3 percent of total emissions covered in the entire initial rule proposal. This in large measure was due to the fact that essentially 100 percent of the original rule proposal Subpart W emissions were leak detection and direct measurement. In the supplemental rule proposal, the percentage of total fugitive and vented emissions directly spot measured has been reduced to 6 percent.

– The methodology selected for individual sources in each of the supplemental rule proposal Subpart W segments was determined based on the intent to achieve the most cost effective coverage of emissions. Therefore, in some cases accepted engineering estimates based on facility data is used, in others leak detection coupled with use of average leaking component (i.e. leaker) factors is used (this is more informative data on actual leaks for long term tracking purposes than emissions "population" factors based on component counts).

– Use of population emission factors is proposed in several areas, primarily for minor fugitive sources and also sources that are inaccessible or excessively burdensome for leak detection. To the degree possible, use of these is minimized.

– In the case of offshore production, EPA proposes reporting of existing MMS GOADS emissions results for offshore platforms in Federal Gulf of Mexico (GoM) waters to avoid redundancy of reporting efforts.[9] We have also required that facilities not covered by GOADS (State waters and Federal non-GoM platforms) use data collection and emissions calculation methods in accordance with the MMS GOADS program to reduce burden and make emissions reporting consistent across the segment.

In addition to the Subpart W-specific changes above, the changes affecting all subparts of the final MRR would likewise affect Subpart W reporters. These changes include:

– Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that report less than 25,000 metric tons of CO_2e for 5 years to cease annual reporting to EPA.

– Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that report less than 15,000 metric tons of CO_2e for 3 years to cease annual reporting to EPA.

– Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that stop operating all GHG-emitting processes and operations covered by the rule to cease annual reporting to EPA.

– Added a provision in 40 CFR 98.3 for submittal of revised annual GHG reports to correct errors.

[9] Gulf Offshore Activities Data System (GOADS) is an inventory of air emissions from platforms operating in Federal waters in the Western Gulf of Mexico developed by The Minerals Management Service (MMS). The MMS mandated that all 2525 offshore operators in the Gulf of Mexico conduct annual surveys (in 2000 and 2005) of their GHG and other hazardous pollutants. The MMS collects activity data from each platform that is then used to estimate emissions. The usual cycle for this data collection effort has been once in every three to four years.

- Added, in 40 CFR 98.3, an accuracy specification of plus or minus 5 percent for flow meters.

- Excluded R&D activities from reporting under 40 CFR part 98 by adding an exclusion in 40 CFR 98.2.

- Revised the requirements of the Designated Representative in 40 CFR 98.4 to align them with those in 40 CFR 75 (ARP regulations).

- Changed record retention to 3 years instead of 5 years for most records (40 CFR 98.3).

- In the recordkeeping section (40 CFR 98.3), clarified the contents of the monitoring plan (called the QAPP at proposal).

- Revised several definitions in 40 CFR part 98, subpart A to address comments.

Overall, the difference between the estimated annual cost of the supplemental proposed rulemaking for Subpart W and the estimated annual cost of the original proposed rule results from the inclusion of new segments in Subpart W and the significant reduction in direct emissions spot measurements.

1.3.3 Evaluating Costs and Benefits

To assist in the selection of the selected option EPA conducted an Economic Impact Analysis across the above dimensions for Subpart W. EPA estimated the costs of complying with each of the reporting alternatives, and assessed the cost-effectiveness of each alternative by examining the costs per million metric ton of CO_2 equivalent ($MMtCO_2e$) reported. This cost-effectiveness metric was considered in combination with other important factors such as the potential impacts on small entities, consistency with other CAA or state-level regulatory programs and monitoring methods already in use within the regulated industries.

1.4 Subpart W Selected Greenhouse Gas Reporting Alternative

The selected option for Subpart W of the mandatory GHG reporting rule is outlined below. Section 5 provides cost comparisons for each alternative evaluated under the following two dimensions. The selected option strikes a balance between impacts on small entities, consistency with other programs, costs incurred by the reporting entities, and emissions coverage.

- **Threshold**: 25,000 metric tons CO_2e/year

  - The thresholds for the finalized MRR fall generally into three groups: capacity, emissions, or entire source category (“All in”). In Subpart W, a facility that emits 25,000 metric tons CO_2e/year or more reports all sources for which there are methods specified in the Rule.

- Subpart W facilities determine their applicability by comparing their emissions to a threshold of 25,000 metric tons CO_2e/year.
- Subpart W segments evaluate threshold from an analysis of reported vented and fugitive emissions and stationary combustion-based emissions.

– **Methodology**: Combination of direct measurement and source-specific calculation methodologies

- Direct spot measurement of site or equipment specific emission factors from sources at facilities that were deemed to be essential to collect based on the estimated volume of emissions and the lack of effective alternative methodologies or emissions factors.
- Source-specific engineering calculation methods using facility-specific information for other sources at the facility.
- Source-specific calculation methods for equipment identified to be leaking.
- Source-specific use of population based emission factors for minor vented and fugitive sources or inaccessible sources.

SECTION 2
REGULATORY BACKGROUND

The intent of this rule is to collect accurate and timely GHG emissions data that can be used to inform future policies. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the rule, and how these existing programs treat the petroleum and natural gas industry. The reporting program will supplement rather than duplicate other U.S. government GHG programs. We outline EPA's overall rulemaking approach, sources considered, and summarize our review of GHG monitoring protocols for each petroleum and natural gas system used by federal, state, regional, and international voluntary and mandatory GHG programs, and our review of state mandatory GHG rules below. For example, the monitoring and GHG calculation methodologies for many of the petroleum and natural gas systems are the same as, or similar to, the methodologies contained in state reporting programs. The remainder of the section provides an overview of related existing programs and discusses their relevance in the development of this rule.

2.1 EPA's Overall Rulemaking Approach

In response to the FY2008 Consolidated Appropriations Amendment, EPA has developed this rulemaking. The components of this development are explained in the following subsections.

2.1.1 Identifying the Goals of the Greenhouse Gas Reporting System

The mandatory reporting program outlined in Subpart W will provide comprehensive and accurate data which will inform future climate change policies. Potential future climate policies include research and development initiatives, economic incentives, new or expanded voluntary programs, adaptation strategies, emission standards, a carbon tax, or a cap-and-trade program. Because we do not know at this time the specific policies that will be adopted, the data reported through the mandatory reporting system should be of sufficient quality to support a range of approaches. Also, consistent with the Appropriations Amendment, the reporting rule covers a broad range of source categories in the economy; however, this Economic Impact Analysis for the supplemental proposed rulemaking is specific to Subpart W, petroleum and natural gas systems.

To these ends, we identified the following goals of the mandatory reporting system:

- Obtain data that are of sufficient quality that they can be used to support a range of future climate change policies and regulations.
- Balance the rule coverage to maximize the amount of emissions reported while minimizing reporting from small emitters.

- Create reporting requirements that are consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.

2.1.2 Developing the Rule

For Subpart W, EPA evaluated the requirements of existing GHG reporting programs, obtained input from stakeholders, analyzed reporting options, and developed the general reporting requirements and specific requirements for each of the GHG emitting processes listed in Subpart W.

2.1.3 Evaluation of Existing Greenhouse Gas Reporting Programs

A number of state and regional GHG reporting systems currently are in place or under development. EPA's goal is to develop a reporting rule that, to the extent possible and appropriate, would rely on similar protocols and formats of the existing programs for petroleum and natural gas systems and, therefore, reduce the burden of reporting for all parties involved. Therefore, we performed a comprehensive review of existing voluntary and mandatory GHG reporting programs, as well as guidance documents for quantifying fugitive GHG emissions from the petroleum and natural gas source category. These GHG reporting programs and guidance documents specifically related to the petroleum and natural gas source category include:

- U.S. national programs, such as the U.S. GHG inventory, the ARP, DOE 1605(b) voluntary registry, and voluntary GHG partnership programs (e.g., Natural Gas STAR);
- State and regional GHG reporting programs, such as The Climate Registry (TCR), the Regional Greenhouse Gas Initiative (RGGI), and programs in California, New Mexico, and New Jersey;
- Reporting protocols developed by nongovernmental organizations, such as the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD); and
- Programs from industrial trade organizations, such as the American Petroleum Institute's Compendium of GHG Estimation Methodologies for the Petroleum and Gas Industry.

In reviewing these programs, we analyzed the segments covered, thresholds for reporting, the monitoring or emission estimating methods used, the measures to assure the quality of the reported data, the point of monitoring, data input needs, and information required to be reported and/or retained. We analyzed these provisions for suitability to a mandatory, federal GHG reporting program, and compiled the information. Section 2.3 describes the existing reporting programs examined regarding Subpart W. The full review of existing GHG reporting programs and guidance for all MRR subparts may be found in the docket at EPA-HQ-OAR-2008-0508-054.

2.1.4 Stakeholder Outreach to Identify Reporting Issues

Early in the development process, we conducted a proactive communications outreach program to inform the public about the rule development effort. We solicited input and maintained an open door policy for those interested in discussing the rulemaking. Since January 2008, EPA staff has held more than 100 meetings with stakeholders, including the following:

– trade associations and firms in potentially affected industries/segments;

– state, local, and tribal environmental control agencies and regional air quality planning organizations;

– state and regional organizations already involved in GHG emissions reporting, such as TCR, California Air Resources Board (CARB), and Western Climate Initiative (WCI); and

– environmental groups and other nongovernmental organizations.

– We also met with U.S. Department of Energy (DOE) and U.S. Department of Agriculture (USDA), which have programs relevant to GHG emissions.

During the meetings, we shared information about the statutory requirements and timetable for developing a rule. Stakeholders were encouraged to provide input on key issues. Examples of topics discussed included existing GHG monitoring and reporting programs and lessons learned, thresholds for reporting, schedules for reporting, scope of reporting, handling of confidential data, data verification, and the role of states in administering the program. As needed, the EPA technical workgroups followed up with these stakeholder groups on a variety of methodological, technical, and policy issues. EPA staff also provided information to tribes through conference calls with different Indian tribal working groups and organizations at EPA as well as through individual calls with tribal board members of TCR.[10]

On April 10, 2009 (74 FR 16448), EPA proposed the GHG reporting rule. EPA held two public hearings, and received over 16,000 written public comments. The public comment period ended on June 9, 2009. Subpart W received comments from over 80 entities with over 1,200 pages of comments, recommendations and alternatives for consideration.

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[10] For a full list of organizations EPA met with when developing this rule, please see the EPA docket memo, EPA-HQ-OAR-2008-0508-055.

In addition to the public hearings, EPA had an open door policy, similar to the outreach conducted during the development of the proposal. As a result, EPA met with over 4,000 people and 135 groups between proposal signature (March 10, 2009) and the close of the comment period (June 9, 2009). Details of these meetings are available in the docket (EPA-HQ-OAR-2009-0923)

2.1.5 Analysis of Emissions from the Petroleum and Natural Gas Industry

For each of the petroleum and natural gas system segments mentioned in Section 2.2, EPA compiled information on current conditions in the segment, including information about existing monitoring equipment or reporting frameworks, estimated emissions of GHGs, and estimated productive capacity or throughput. Section 4 summarizes the incremental costs of measuring vented and fugitive GHG emissions and conducting reporting activities for Subpart W facilities. Section 5 presents cost scenarios that vary the conditions of the reporting rule for Subpart W with respect to the size of the entity required to report and the type of measurement required of the petroleum and natural gas segment. The scenarios specific to Subpart W are listed in Section 3. EPA also reviewed the benefits to stakeholders, including the public, the government, and industry, of a reporting system for petroleum and natural gas fugitive emissions in a qualitative analysis. These benefits are outlined in Section 5.

2.2 Sources Considered

A technical subgroup on fugitive and vented emissions considered the following sources of emissions from the petroleum and natural gas industry, as shown in Table 2-1. Using screening criteria based on the feasibility of monitoring, verifying, and measuring these sources, the technical subgroup developed reporting methodologies for the sources in Subpart W identified in Table 2-2.

Table 2-1 Sources of GHG Emissions Considered

Source	Subpart W: GHG Emission Considered
Downstream	
Direct emitters	**Stationary combustion**: Sources considered include stationary combustion units (e.g., EGUs, boilers, furnaces, turbines, skid mounted portable equipment).
	Vented emissions: Intentional or designed emissions result from the extraction, processing, storage, and transport of fossil fuels (coal, petroleum, and natural gas) to the point of final use. Examples include compressor seal vents, storage tank vents, or pneumatic device emissions.
	Fugitive emissions: Emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. Examples include leaks from valves and connectors.
	Flare combustion: Intentional and unintentional emissions result from the extraction, processing, storage, and transport of fossil fuels (coal, petroleum, and natural gas) to the point of final use.

Table 2-2 Segments Included in the Petroleum and Natural Gas Regulatory Analyses

Subpart W Segments
Onshore petroleum and natural gas production
Offshore petroleum and natural gas production
Natural gas transmission
Natural gas processing
Natural gas underground storage
LNG storage
LNG import & export terminals
Natural gas distribution

2.3 How the Mandatory GHG Reporting Program Is Different from the Federal and State Programs EPA Reviewed

The various existing state and federal programs EPA reviewed are diverse. They have different thresholds, require different pollutants and different types of emissions sources to be reported, rely on different monitoring protocols, and require different types of data to be reported, depending on the purposes of each program. None of the existing programs require nationwide, mandatory GHG reporting by facilities in a large number of segments, so EPA's mandatory GHG rule is unique in this regard. The remainder of this section focuses on existing state and federal programs that apply to petroleum and natural gas systems covered under Subpart W.

Although the mandatory GHG rule is unique, EPA carefully considered other Federal and State programs during development of the rule. Documentation of our review of GHG monitoring protocols for each source category used by federal, state, and international voluntary and mandatory GHG programs, and our review of State mandatory GHG rules can be found at EPA-HQ-OAR-2008-0508-056. The monitoring and GHG calculation methodologies for many source categories are the same as, or similar to, the methodologies contained in State reporting programs such as TCR, CCAR (California Climate Action Registry), and State mandatory GHG reporting rules and similar to methodologies developed by EPA voluntary programs such as Climate Leaders. Similarity in methods will help maximize the ability of individual reporters to submit the emissions calculations to multiple programs, if desired. EPA will continue to work closely with states and state-based groups to ensure that the data management approach in this rule will lead to efficient submission of petroleum and natural gas data to multiple programs.

The intent of this rule is to collect a reasonable estimate of GHG emissions data that can be used to inform future policy decisions. One goal in developing the rule is to be consistent with the GHG protocols and requirements of other state and federal programs, where appropriate, in order to make use of existing cooperative efforts and reduce the burden to petroleum and natural gas facilities submitting reports to other programs. However, we also need to be sure the mandatory reporting rule collects facility-specific vented and fugitive emissions data of sufficient quality to achieve the Agency's objectives. Therefore, some reporting requirements of this rule related to petroleum and natural gas fugitive emissions are different from other federal and state programs.

2.3.1 Inventory of U.S. Greenhouse Gas Emissions and Sinks

The U.S. greenhouse gas inventory, prepared by EPA's Office of Atmospheric Programs in coordination with the Office of Transportation and Air Quality, is an impartial, policy-neutral report that tracks annual GHG emissions. The annual report presents historical U.S. emissions of CO_2, CH_4, N_2O, hydroflurocarbons, perflurocarbons, and sulfur hexafluroide.

The United States submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The UNFCCC treaty, ratified by the United States in 1992, sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The United States has submitted the GHG inventory to the United Nations every year since 1993. The annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is consistent with national inventory data submitted by other UNFCCC parties, and uses internationally accepted methods for its emission estimates.

In preparing the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, EPA leads an interagency team that includes the DOE, USDA, the Department of Transportation (DOT), the Department of Defense (DOD), the State Department, and others. EPA collaborates with hundreds of experts representing more than a dozen federal agencies, academic institutions, industry associations, consultants, and environmental organizations. The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is peer-reviewed annually by domestic experts and by UNFCCC, and undergoes a 30-day public comment period, and is peer reviewed annually by UNFCCC review teams.

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is a comprehensive, top-down national assessment of national greenhouse gas emissions, and uses top-down national energy data and other national statistics. To achieve the goal of comprehensive national emissions coverage for reporting under the UNFCCC, most GHG emissions in the report are calculated via activity data from national-level databases, statistics, and surveys. The use of the aggregated national data means that the national emissions estimates are not broken down at the geographic or facility level. In contrast, this reporting rule focuses on bottom-up data and individual sources above appropriate thresholds.

The Inventory contains estimates of vented, fugitive and combustion emissions from petroleum systems and from natural gas systems, which are both IPCC source categories. Regarding the quantification of CH_4 emissions from natural gas systems, reductions achieved through the Natural Gas STAR program and National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations are included (see below for more details on these programs). A detailed study by the Gas Research Institute[11] and EPA (GRI/EPA 1996) is used as the basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry in the report.

[11] Now the Gas Technology Institute

For Petroleum and Natural Gas systems, EPA has been aware that there are a number of areas where the 2008 U.S. Greenhouse Gas Inventory Report assumptions may substantially underestimate actual emissions levels. The supplemental proposed rule for Subpart W is estimated to significantly increase the level of emissions covered than included in the 2008 U.S. Greenhouse Gas Inventory Report by reflecting improved estimates of emissions from key sources such as well liquid unloadings, well workovers, well completions and compressor wet seal degassing vents. These estimates are based on publicly available information from the EPA Natural Gas Star website and assumptions based on expert judgment.

The supplemental proposed rule for Subpart W will therefore help to improve the development of future national inventories for Petroleum and Natural Gas Systems by improving the estimates of emissions and thereby advance the understanding of emission processes and monitoring methodologies. Facility, unit, and process level GHG emissions data for all sources will improve the accuracy of future U.S. Greenhouse Gas Inventory Reports by confirming the national statistics and emission estimation methodologies used to develop the top-down inventory. The results can confirm shortcomings in the national statistics and identify where adjustments may be needed.

Therefore, although the data collected under this rule will not replace the system in place to produce the comprehensive annual national Inventory, it can serve as a useful tool to better improve the accuracy of future national-level inventories.

2.3.2 Federal Voluntary Greenhouse Gas Programs

EPA and other federal agencies operate a number of voluntary GHG reporting and reduction programs that EPA reviewed when developing this proposal, including several non-CO_2 voluntary programs, and the DOE 1605(b) voluntary GHG registry. Several other federal voluntary programs encourage emissions reductions, clean energy, or energy efficiency; this summary does not cover them all (for additional information see *Review of Existing Programs*, EPA-HQ-OAR-2008-0508-054). This summary focuses on programs that include voluntary GHG emission inventories or reporting of GHG emissions reduction activities for sources that were considered for inclusion in Subpart W of this supplemental proposed rulemaking.

2.3.2.1 Non-CO_2 Voluntary Partnership Programs

Since the 1990s, EPA has operated a number of non-CO_2 voluntary partnership programs aimed at reducing emissions from GHGs such as methane, SF_6, and PFCs. There are four segment-specific voluntary methane reduction programs: Natural Gas STAR, Landfill Methane Outreach Partnership (LMOP), Coalbed Methane Outreach Programs (CMOP), and Ag STAR.

In addition, there are segment-specific voluntary emissions reduction partnerships for high global warming potential gases. The program specific to those entities that fall under Subpart W is the Natural Gas STAR partnership, which encourages companies across the natural gas and petroleum industries to adopt practices that reduce methane emissions. Industry partners voluntarily provide technical information on projects they undertake to reduce methane emissions on an annual basis, but they do not submit methane emissions inventories.

2.3.2.2 1605(b) Voluntary Registry

The DOE Energy Information Administration (EIA) established a voluntary GHG registry under Section 1605(b) of the Energy Policy Act of 1992. The program was recently enhanced and a final rule containing general reporting guidelines was published on April 21, 2006 (71 FR 20784); the rule is contained in 10 CFR Part 300. Unlike EPA's proposal, which requires reporting of greenhouse emissions from facilities over a specific threshold, the DOE 1605(b) registry allows anyone (e.g., a public entity, private company, or an individual) to report their emissions and their emissions reduction projects to the registry. Large emitters (e.g., anyone that emits over 10,000 metric tons of CO_2e per year) who wish to register emissions reductions must submit annual company-wide GHG emissions inventories following technical guidelines published by DOE and must calculate and report net GHG emissions reductions. The program offers a range of reporting methodologies from stringent direct measurement to simplified calculations using default factors and allows the reporters to report using the methodological option they choose. For the petroleum and natural gas industry, some methods for estimating emissions are outlined, but this petroleum and natural gas section in the 1605(b) ***Technical Guidelines*** is only meant to serve as a guide. Reporters can use established, published authorities' estimation methods, which must be referenced. In addition, as mentioned above, unlike EPA's proposal, sequestration and offset projects can also be reported under the 1605(b) program. There is additional flexibility offered to small sources that can choose to limit annual inventories and emissions reduction reports to a single type of activity rather than reporting company-wide GHG emissions, but must still follow the technical guidelines. Reported data are made available on the Internet in a public use database.

2.3.2.3 Summary

These voluntary programs are different in nature from the mandatory GHG emissions reporting rule. Industry participation in the programs and reporting to the programs is entirely voluntary. A small number of sources report, compared to the number of facilities that will likely be affected by Subpart W of the mandatory GHG reporting rule. Most of the EPA voluntary programs do not require reporting of annual emissions data, but are instead intended to encourage GHG reduction activities and track partners' successes in implementing such projects.

At the same time, aspects of the voluntary programs serve as useful starting points for the mandatory GHG reporting rules. Greenhouse gas emission calculation principles and protocols have been developed for various types of emission sources by Climate Leaders, the DOE 1605(b) program, and some partnerships such as the SF_6 reduction partnerships and SmartWay. Under these protocols, reporting companies monitor process or operating parameters to estimate greenhouse emissions, report annually, and retain records to document their GHG estimates. Through the voluntary programs, EPA, DOE, and participating companies have gained understanding of processes that emit GHGs and experience in developing and reviewing GHG emission inventories.

2.3.3 Federal Mandatory Reporting Programs

2.3.3.1 Toxics Release Inventory (TRI)

TRI requires facility-level reporting of annual mass emissions of approximately 650 toxic chemicals. If they are above established thresholds, facilities in a wide range of industries report including manufacturing industries, the petroleum industry, and other industrial segments. Facilities must submit annual reports of total stack and fugitive emissions of the listed toxic chemicals using a standardized form which can be submitted electronically. No information is reported on the processes and emissions points included in the total emissions. The data reported to TRI are not directly useful for the GHG rule because TRI does not include GHG emissions and does not identify processes or emissions sources. However, the TRI program is similar to the GHG reporting rule in that it requires direct emissions reporting from a large number of facilities (roughly 23,000) across all major industrial segments. Therefore, EPA reviewed the TRI program for ideas regarding program structure and implementation.

2.3.4 Other EPA Emissions Inventories

2.3.4.1 National Emissions Inventory

EPA compiles the National Emissions Inventory (NEI), a database of air emissions information provided primarily by state and local air agencies and tribes. The database contains information on stationary and mobile sources that emit criteria air pollutants and their precursors, as well as hazardous air pollutants. Stationary point source emissions that must be inventoried and reported are those that emit over a threshold amount of at least one criteria pollutant. Many states also inventory and report stationary sources that emit amounts below the thresholds for each pollutant. The point source NEI includes over 60,000 facilities. Required point source information consists of facility identification information; process information detailing the types of air pollution emission sources, air pollution emission estimates (including annual emissions), control devices in place, stack parameters, and location information. The NEI differs from the GHG reporting rule in that the NEI contains no GHG data, and the data are reported primarily by State agencies rather than directly reported by industries. However, in developing the rule, EPA used the NEI to help determine sources that might need to report under Subpart W of the GHG reporting rule. We considered the types of facility, process and activity data reported in NEI to support the emissions data as a possible model for the types of data to be reported under the GHG reporting rule.

2.3.5 State and Regional Voluntary Programs for Greenhouse Gas Emissions Reporting

A number of States have demonstrated leadership and developed corporate voluntary GHG reporting programs individually or joined with other States to develop GHG reporting programs as part of their approaches to addressing GHG emissions. The following discussion summarizes two prominent voluntary efforts. In developing the greenhouse rules, EPA reviewed the relevant protocols used by these programs as a starting point. We recognize that these programs may have additional monitoring and reporting requirements than those outlined in the rule in order to provide distinct program benefits.

2.3.5.1 California Climate Action Registry

The California Climate Action Registry (CCAR) is a voluntary GHG registry already in use in California. CCAR has released several methodology documents, including a general reporting protocol, general certification (verification) protocol, and several segment-specific protocols. Companies submit emissions reports using a standardized electronic system. Emission reports may be aggregated at the company level or reported at the facility level. CCAR is transitioning out of entity emissions reporting, and 2009 will be the last year it accepts such reporting. Emissions reporting can instead be conduced under CCAR’s sister organization The Climate Registry (TCR), which is based off of CCAR’s work. A number of members of CCAR have already made the transition over to TCR.

2.3.5.2 The Climate Registry

The Climate Registry (TCR) is a partnership formed by U.S. and Mexican states, Canadian provinces, and tribes to develop standard GHG emissions measurement and verification protocols and reporting system capable of supporting mandatory or voluntary GHG emission reporting rules and policies for its member states. TCR has released a final General

Reporting Protocol that contains procedures to measure and calculate GHG emissions from a wide range of source categories. They have also released a general verification protocol, and an electronic reporting system. Several industry-specific draft protocols have been released recently for public comment including an *Petroleum & Gas Exploration & Production Protocol* and a verification protocol for this segment. Founding reporters (companies and other organizations that have agreed to voluntarily report their GHG emissions) implemented a pilot reporting program in 2008. Annual reports will be submitted covering six GHGs. Corporations must report facility-specific emissions broken out by type of emission source (e.g., stationary combustion, mobile combustion, process, fugitive and indirect) and gas (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) within each facility.

2.3.6 State and Regional Mandatory Programs for Greenhouse Gas Emissions Reporting and Control

Several individual States and regional groups of States have demonstrated leadership and are developing or have developed mandatory GHG reporting programs and GHG emissions control programs. This section of the preamble summarizes two regional cap-and-trade programs and several State mandatory reporting rules, which cover, or for those programs still under development, have the potential to cover the petroleum and natural gas segment. We recognize that, like the current voluntary regional and State programs, State and regional mandatory reporting programs may evolve or develop to include additional monitoring and reporting requirements than those included in the rule. In fact, these programs may be broader in scope or more aggressive in implementation because the programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific measures that indirectly reduce GHG emissions (e.g., energy efficiency).

2.3.6.1 Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a regional cap-and-trade program that covers CO_2 emissions from EGUs larger than 25 MW in member states in the Mid-Atlantic and Northeast. The program goal is to reduce CO_2 emissions to 10% below 1990 levels by the year 2020. Certain types of offset projects will be allowed, and GHG offset protocols have been developed. The states participating in RGGI have adopted state rules (based on a model rule) to implement RGGI in each state. The RGGI cap-and-trade program took effect on January 1, 2009. There has been some discussion of regulating additional sources of GHG emissions under the RGGI program in the future.

2.3.6.2 Western Climate Initiative

WCI is another regional cap-and-trade program being developed by a group of Western States and Canadian provinces. The goal is to reduce GHG emissions to 15 percent below 2005 levels by the year 2020. Draft options papers and program scope papers were released in early 2008, public comments were reviewed, and final program design recommendations were made in September 2008. Other elements of the program, such as reporting requirements, market operations, and offset program development continue. WCI released its final version of the first group of Essential Requirements for Mandatory Reporting (ERMR) in July 2009, and it is anticipated that WCI jurisdictions will have rules implementing these reporting requirements in place for the 2010 reporting year or shortly thereafter. Petroleum and natural gas production facilities are not listed in the first reporting group, although petroleum refiners must report. Several source categories are being considered for inclusion in the cap and trade framework. One such category is "industrial process emission sources, including petroleum and natural gas process emissions[12]," meaning that sources covered under Subpart W of the Federal reporting rule may also be regulated under a future WCI program. The program might be phased in, starting with a few source categories and adding others over time. Points of regulation for some source categories, calculation methodologies, and other reporting program elements are under development. The WCI is also analyzing alternative or complementary policies other than cap-and-trade that could help reach GHG reduction goals. Options for rule implementation and for coordination with other rules and programs such as TCR are being investigated.

2.3.7 State Mandatory Greenhouse Gas Reporting Rules

Seventeen states have developed, or are developing, mandatory GHG reporting rules.[13] The docket for the final MRR (74 FR 56260, October 30, 2009) contains a summary of these state mandatory rules (EPA-HQ-OAR-2008-0508-056). Final rules have not yet been developed by some of the states, so details of some programs are unknown. Reporting requirements have already entered into effect in twelve states as of 2009; the rest will begin between 2010 and 2012. Reporting is typically annual, although some states require quarterly reporting for EGUs, consistent with RGGI.

State rules differ with regard to which facilities must report and which GHGs must be reported. Some states require all facilities that must obtain Title V permits to report GHG

[12] In the WCI design recommendations, process emissions are defined as including emissions from chemical, biological, and other non-combustion processes. These emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental.

[13] These are California, Colorado, Connecticut, Delaware, Hawaii, Iowa, Maine, Maryland, Massachusetts, New Jersey, New Mexico, North Carolina, Oregon, Virginia, Washington, West Virginia, and Wisconsin.

emissions. Others require reporting for particular segments (e.g., large EGUs, cement plants, refineries). Some state rules apply to any facility with stationary combustion sources that emit a threshold level of CO_2. Some apply to any facility, or to facilities within listed industries, if their emissions exceed a specified threshold level of CO_2e. Many of the state rules apply to six GHGs covered by the final MRR (CO_2, methane, nitrous oxide, HFCs, PFCs, SF_6); others apply only to CO_2 or a subset of the six gases. Most require reporting at the facility level, or by unit or process within a facility.

The level of specificity regarding GHG monitoring and calculation methods varies. Some of the states refer to use of protocols established by TCR or CCAR, to industry-specific protocols (such as methods developed by the American Petroleum Institute [API]), to accepted international methodologies such as IPCC, and/or to emission factors in EPA's *Compilation of Air Pollutant Emission Factors* (known as AP-42) or other EPA guidance.

2.3.7.1 California Mandatory Greenhouse Gas Reporting Rule

The mandatory reporting rule of the California Air Resources Board (CARB) is an example of a state rule that covers multiple source categories and contains relatively detailed requirements, similar to this proposal developed by EPA. The regulation became effective on January 2, 2009. According to CARB, selected facilities (e.g. general stationary combustion facilities outside the petroleum-and-gas segment, and electricity generation and cogeneration plants not within the operational control of larger facilities and entities) are required to file their first emissions data reports by April 1, 2009. The rest of the facilities and entities report by June 1, 2009 (see http://www.arb.ca.gov/cc/reporting/ghg-rep/ghgschedadvisory.pdf). The rule requires facility-level reporting of all GHGs (except PFCs) from cement manufacturing plants, electric power generation and retail markets, cogeneration plants, petroleum refineries, hydrogen plants, and facilities with stationary combustion sources emitting greater than 25,000 metric tons CO_2 per year. The California rule does not impact those facilities that would be subject to reporting under Subpart W of the Federal reporting rule. Part 75 (Acid Rain Program) data will be used for EGUs. The regulation contains specific GHG estimation methods that are largely consistent with CCAR protocols, and also relies on API protocols and IPCC/European Union protocols for certain types of sources. California continues to participate in other national and regional efforts, such as TCR and WCI, to assist with developing consistent reporting tools and procedures on a national and regional basis.

SECTION 3
DEVELOPMENT OF THE MANDATORY REPORTING RULE

To develop Subpart W of the Mandatory GHG Reporting Rule, EPA considered various dimensions of the reporting program and developed and evaluated several options for each dimension. After a preliminary evaluation of the options for each dimension, a recommended reporting program alternative was selected. Several possible program alternatives were selected, generally by varying one dimension at a time, while retaining the recommended option for the other dimensions. These alternatives were then evaluated based on estimated cost, cost-effectiveness (cost per metric ton of emissions reported), and estimated impacts on small entities. This process is discussed in greater detail below.

3.1 Rule Dimensions for Which Options Were Identified

Possible designs for Subpart W of the Mandatory GHG Reporting Rule were developed by varying options across two dimensions:

1. **Thresholds**: Based on the discretion in the language of the appropriations bill that calls for emissions reporting above appropriate thresholds in all segments of the economy, EPA has identified an appropriate threshold above which petroleum and natural gas facilities are required to report their GHG emissions. Types of thresholds considered were production or productive capacity, and emissions based.

2. **Measurement Methodology**: To be able to report their GHG emissions, facilities will be required to measure them using an appropriate methodology. Generally, measurement methodologies may be based on instrumentation and direct measurement, or on calculation of measurements based on other data available to the facility (e.g., activity data and emissions factors).

The options EPA considered for each dimension for Subpart W sources are discussed below and summarized in Table 3-1. The table shows a column identifying the options for each specific dimension. Shaded boxes represent recommended options.

Table 3-1 Options Considered in Developing Scenarios for Regulation under Subpart W (Recommended Option Indicated by Shading)

Threshold	Methodology
Capacity-based	Direct measurement (CEMS)
Emissions based 1,000mtCO_2e	Hybrid: Direct spot measurement for major emissions sources and facility-specific calculations for others
Emissions-based 10,000 mtCO_2e	Default emissions factors from EPA
Emissions-based 25,000 mtCO_2e	
Emissions-based 100,000 mtCO_2e	
Hybrid: 25,000 mtCO_2e unless already reporting based on capacity under another program	

3.1.1 Thresholds

Three options were considered in setting the threshold above which reporting of GHG emissions will be required for Subpart W: capacity-based thresholds, emissions-based thresholds, or a hybrid of the two. Within each option, various definitions and levels of the threshold were examined.

3.1.1.1 Option 1: Capacity-based threshold

A capacity-based threshold would be defined based on the emitting facility's throughput, production, or productive capacity. In defining the capacity-based threshold, EPA considered that using a source-level capacity measure for the threshold might be a more straightforward way for facilities to know that they must report their GHG emissions, but the data on source-level capacity is not currently universally available to EPA.

3.1.1.2 Option 2: Emissions-based threshold (recommended)

Option 2 involves the use of actual facility-level emissions of GHGs, measured in metric tons of CO_2-equivalent emissions (tCO_2e). Various levels were considered, ranging from 1,000 tCO_2e to 100,000 tCO_2e. Obviously, lower thresholds would require more facilities to participate in the reporting program. Given current data availability, an emissions-based threshold will generally focus on larger, emissions-intensive sources in the petroleum and natural gas segment for which emissions data are readily calculated or measured.

3.1.1.3 Option 3: Hybrid

The hybrid threshold option is a combination of three general groups: capacity, emissions, or entire source category ("All in"). The thresholds developed are generally equivalent to a facility-wide threshold of 25,000 metric tons of CO_2e per year of actual emissions. The preference is to establish thresholds for as many source categories as possible based on a capacity metric, for example, tons of product produced per year. A capacity-based threshold is least burdensome, because a facility would not have to estimate emissions to determine if the rule applies. However, EPA faces two key challenges in trying to develop capacity thresholds. First, in most cases, especially involving fugitive and vented emissions under Subpart W, data are insufficient to determine an appropriate capacity threshold. Secondly, in many of the petroleum and natural gas segments, the level of emissions from vented and fugitive sources is not related to capacity or throughput. Rather, emissions may be driven by design and operating factors. As an example, pneumatic controls on petroleum and natural gas facilities are designed to vent natural gas to drive valve movements. The level of venting is not dependent on throughput.

3.1.2 Measurement Methodology

EPA identified three measurement methodology options, ranging from installing emissions monitoring equipment on all sources under Subpart W to using default emissions factors to estimate emissions. The measurement methodology options considered for Subpart W sources are discussed below.

3.1.2.1 Option 1: Direct measurement for all reporters

This option would apply direct measurement requirements to all reporters. This would require facilities subject to Subpart W to use fuel flow meters for gaseous fuels and for spot measurement of vented emissions from various equipment. In addition, it would require spot leak detection and quantification of emissions by use of calibrated bagging or high volume samplers throughout all segments. This option was the selected option for the original proposed rule for Subpart W (74 FR 164888, April 10, 2009).

3.1.2.2 Option 2: Hybrid of direct measurement and facility-specific calculation for other sources (recommended)

EPA's current recommended measurement methodology option for Subpart W is a hybrid of direct measurement and facility-specific calculations, which is considerably less burdensome than Option 1. Specifically, EPA recommends the use of direct spot measurement where reliable emissions factors do not exist and engineering calculations based on site-specific information to estimate emissions from the largest emission sources. Other sources will be quantified through the use of leak detection and application of emissions factors for leaking equipment (i.e. “leaker” factors). Use of population count and default population emissions factors are used for smaller and inaccessible sources.

The hybrid approach results in a significantly lower cost burden to reporting parties yet provides a much more robust development of GHG emissions. Unlike Option 3, which is described below, Option 2 will enable EPA to monitor year-to-year changes in emissions levels from the petroleum and natural gas source category.

3.1.2.3 Option 3: Default emissions factor calculation for both combustion and process emissions

Under Option 3, EPA would require petroleum and natural gas facilities to base their reported emissions on simplified calculations performed at the facility level, based on EPA-provided default factors combined with the type of process, production rate, and/or the quantity of fuel/chemical inputs used.

3.2 Selected Option

As described above, EPA evaluated a variety of options for each dimension of the GHG reporting program, and selected a preferred or recommended option for each dimension. We summarize the recommended option for each dimension below.

- **Threshold**: Emissions based approach
  - For Subpart W sources, applicability is based on emissions. Emissions are the sum of vented and fugitive emissions sources and stationary combustion emissions, as well as emissions from any other source category covered by the finalized MRR that may be present at the facility. A facility that emits 25,000 metric tons CO_2e/year or more reports all sources for which there are proposed methods.
  - For several segments in Subpart W, it was determined appropriate to develop the threshold calculation by defining “facility” differently:
    - For onshore petroleum and natural gas production, the facility is defined as the equipment covered in the proposed rule and owned or operated by a single entity, as defined by the holder of a state-issued permit, located in a petroleum basin. EPA also analyzed the same facility definition, but as applied to a petroleum field, as opposed to a petroleum basin. As described in the Preamble, the threshold

determination and cost burden is recommended to be based on the basin level approach.

  - For natural gas distribution a facility is defined as the local distribution company (LDC). Therefore the threshold is based on total company level emissions of the LDC.

- **Methodology**: Combination of direct measurement and source-specific calculation methodologies

  - For Subpart W, EPA is recommending the use of direct spot measurement and/or engineering calculations using site specific information to estimate emissions from the largest emission sources. In addition, sources which are smaller, or may be inaccessible to direct measurement will be quantified through the use of leak detection and application of emissions factors for leaking equipment. Use of population count and population emissions factors are used for smaller and inaccessible sources.
  - Source-specific calculation methods using facility-specific information for other sources at the facility subject to Subpart W;

3.3 Alternative Scenarios Evaluated

EPA developed alternative reporting scenarios and assessed the costs and emissions associated with each. Alternative scenarios were developed by creating the recommended scenario (the recommended option for each dimension, as shown in Table 3-1), then varying the levels in one dimension while keeping the other three dimensions at the recommended options. The alternative reporting scenarios evaluated for Subpart W are listed below:

1. A 1,000 $mtCO_2e$ threshold; recommended options for methodology.

2. A 10,000 $mtCO_2e$ threshold; recommended options for methodology.

3. A 100,000 $mtCO_2e$ threshold; recommended options for methodology.

4. Direct techniques (CEMS, flow meters) are used to measure emissions; recommended option for threshold.

5. Default emissions factors (simplified methods) are used to measure emissions; recommended option for threshold.

The evaluation of the alternative reporting scenarios will allow policy makers, regulated entities, and the general public to see the impact of each variation and assess their cost compared to the recommended option. Total costs, emissions, and cost-effectiveness of the alternative reporting scenarios for the petroleum and natural gas industry pursuant to Subpart W are discussed in Section 4.

3.4 Data Quality for This Analysis

EPA gathered existing data from EPA, industry trade associations, states, and publicly available data sources (e.g., labor rates from the Bureau of Labor Statistics [BLS]) to characterize the processes, sources, segments, and facilities affected. Costs were estimated based on the data collected and engineering analysis and models provided by EPA and its contractors. EPA staff and contractors provided engineering expertise, knowledge of existing facility conditions and activities, and an estimate of incremental activities required to comply with the rule. Existing models, such as EPA's CEMS "continuous emissions monitoring system" cost model, were used for Subpart W to ensure consistency of cost inputs and assumptions.

The most important elements affecting the data quality for this analysis include the number of affected facilities in each source category, the number and types of production processes that emit GHGs, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and the measurements that are already being made for reasons not associated with the rule (to allow only the incremental costs to be estimated). The background information for standards development, often collected from petroleum and natural gas industry surveys, was supplemented from numerous sources, including industry surveys from the U.S. Census Bureau, trade associations, and operating permits. Information on measurements that are already made (and thus would not be associated with the rule) was obtained from discussions with industry representatives, knowledge gained from previous site visits, and other sources. The data collected to characterize the facilities in Subpart W are judged to be of good quality and the best that are publicly available.

Other elements affecting the quality of the data include estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored for Subpart W; and engineering judgment. Labor costs were taken from the BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring. The data quality associated with these elements of the cost analysis is analogous to the quality of data used in the development of numerous other Information Collection Requests.

SECTION 4
ENGINEERING COST ANALYSIS

4.1 Introduction

EPA estimated costs for each facility under Subpart W to comply with the rule and report fugitive and vented GHG emissions. EPA used available industry and EPA data to characterize conditions at affected sources (i.e., affected facilities). Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility, and the associated costs were estimated for Subpart W. We present the reporting and verification requirements for petroleum and natural gas systems in Table 4-1.

Table 4-1 Selected Reporting Thresholds and Reporting Requirements

Subpart (Source Category)	Segment	Reporting and Verification
W—Petroleum & Natural Gas Systems (§98.230)	Production (onshore and offshore) Natural gas processing Natural gas transmission compression Natural gas underground storage LNG storage LNG import and export terminals Natural gas distribution	(a) Annual emissions reported separately for each of the operations listed in (a)(1) through (8) of this paragraph. Within each operation, emissions from each source type must be reported in the aggregate. For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number. (1) Onshore petroleum and natural gas production facilities (2) Offshore petroleum and natural gas production facilities; (3) Onshore natural gas processing facilities; (4) Onshore natural gas transmission compression facilities; (5) Underground natural gas storage facilities; (6) Liquefied natural gas storage facilities; (7) Liquefied natural gas import and export facilities; (8) Natural gas distribution facilities (b) Emissions reported separately for standby equipment; (c) Report activity data for each aggregated source type level for which emissions are being reported; (d) Activity data for each aggregated source type level for which emissions are being reported. (e) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (8) of this section; and (f) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing petroleum, gas, or both.

Note: Many facilities that would be affected by the rule emit GHGs from multiple sources. The facility must assess every source category that could potentially apply to each when determining if a threshold has been exceeded. If the threshold is exceeded for any source category, the facility must report emissions from all source categories, including those source categories that do not exceed the applicable threshold.

4.2 Overview of Cost Analysis

The costs of complying with the rule will vary from one facility to another, depending on the types of emissions, the number of affected sources at the facility, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with Subpart W. All costs referred to in this section are reported in 2006 dollars.

There are two major categories for which costs are determined. One is the cost to quantify fugitive and vented emissions; the other is the cost to quantify the additional combustion-related emissions for facilities that did not exceed the Subpart C threshold with only combustion emissions. Overall costs presented for Subpart W aggregate process and combustion emissions above those covered by Subpart C alone.

We first provide a general overview of baseline reporting (if data are available); two cost components associated with this information collection; labor costs (i.e., the cost of labor by facility staff to meet the information collection requirements of the rule); and capital and operating and maintenance costs (e.g., the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information). Additional details of the data, methods, and assumptions underlying the costs are documented in this section.

4.2.1 Baseline Reporting

In general, the Subpart W analysis assumes that none of the facilities in the covered segments are currently reporting fugitive and vented emissions and that many of the requirements will result in "new" or "full" costs to meet reporting requirements. Specifically, we assume that there will be additional costs for any detection, sampling and testing requirements in the methods used to quantify emissions from petroleum and natural gas sources. We are also assuming that additional costs will be incurred for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records. The only significant element for these sources that we know is performed routinely by all companies in Subpart W is that they have measurements and records of consumption of raw materials such as feedstocks as part of their routine operation for accounting purposes.

4.2.2 Reporting Costs

Costs for Subpart W were developed based on assessments of all estimated capital and operations and maintenance costs to monitor, measure, detect and calculate the emissions sources in all segments of Subpart W. Key variables and data fields were clearly defined to ensure that each segment developed costs around a standard set of methods and assumptions for Subpart W (e.g., method for annualization of capital costs, interest rate to be applied to capital). Cost estimates were developed for each threshold of emissions based on the number of reporting entities in that threshold group and estimates of the specific capital and labor costs associated with conducting the emissions reporting.

Labor Costs. The costs of complying with and administering this rule include the time of managers, technical, and administrative staff in both the private segment and the public segment. Staff hours are estimated for activities including:

- monitoring (private): staff hours to operate and maintain emissions monitoring systems;
- reporting (private): staff hours to gather and process available data and reporting it to EPA through electronic systems; and
- assuring and releasing data (public): staff hours to quality assure, analyze, and release reports.

Staff activities and associated labor costs may vary over time. Thus, cost estimates are developed for start-up, first-time reporting, and subsequent reporting.

Loaded hourly labor rates (also referred to as "wage rates") were developed for several labor categories to represent *the employer costs to use an hour of employees' time* in each of the manufacturing segment labor categories used in this analysis. The labor categories correspond to the job responsibilities of the personnel that are likely to be involved in GHG emissions monitoring activities at the petroleum or natural gas facility to comply with the rulemaking.

For purposes of this study, EPA adopted the methodology used by Rice (2002) to calculate the wage rates for the EPA's Toxics Release Inventory (TRI) Program. Thus, the *wage rates* calculated for different labor categories included the *employer costs for employee compensation* (comprising the basic wages and the corresponding benefits) and *the overhead costs to the employer*[14].

For each labor category applicable to Subpart W, the following formula was used to calculate the wage rates:

Loaded Hourly Labor Rate ($/hr.) = Basic Wages ($/hr.) *
(1 + Benefits Loading Factor + Overhead Loading Factor).

The *benefits loading factor* corresponds to the relative share of benefits compensation in the total employee compensation (comprising basic wages and benefits). Although the benefits factor tends to vary by labor category and by industry (0.37 to 0.50), for purposes of this

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14 For each employee, the employer also incurs *overhead costs* (comprising the rental costs of the office space, computer hardware and software, telecommunication and other equipments, organizational support, etc.) required for and used by the employee to effectively fulfill his/her job responsibilities. These costs are over and above the employee compensation costs.

analysis, we have assumed the benefits loading factor to remain the same for each labor category across all industries in the rule due to a lack of availability of necessary industry-specific data on benefits paid to employees.

The *overhead loading factor* corresponds to the share of overhead costs to the employer relative to the total employee compensation. For purposes of this analysis, we have also adopted the same overhead loading factor that Cody Rice (2002) used in her wage rate calculations. Thus the overhead loading factor that we used in the wage rate calculations remains the same for all labor categories and across all industry types in the rule. The overhead loading factor was assumed to be 0.17.

For Subpart W, the combined "Benefits and Overhead Loading Factor" used is 0.67, or an overall adjustment of 1.67 times "Basic Wages."

Capital and O&M Costs. This includes the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information. Equipment costs include both the initial purchase price of monitoring equipment and any facility/process modification that may be required. Based on expert judgment, the engineering costs analyses annualized capital equipment costs with the appropriate lifetime and interest rate assumptions. The equipment life was set at five years for Subpart W sources with one-time capital costs amortized at a rate of seven percent.

Other Recordkeeping and Reporting. Additional recordkeeping and reporting costs are added to Subpart W sources based on each segment's estimated requirements. These costs are included in the "process emissions" total estimated costs.

4.3 Subpart W—Petroleum and Natural Gas Systems

Overview. The relevant reporters covered in this section are offshore petroleum and natural gas production facilities, onshore petroleum and natural gas production companies (including enhanced oil recovery, EOR), onshore natural gas processing facilities (including gathering/boosting stations), onshore natural gas transmission compression facilities, onshore natural gas storage facilities, LNG storage facilities, LNG import and export facilities and natural gas distribution facilities.

For each of the industry segments, with the exception of onshore production, operations had to be divided into single units or model facilities at three levels; "small," "medium," and "large." The monitoring costs were then developed per size level of a model facility. A model facility of a given level can be defined as the most convenient and logical unit with appropriate emissions source counts that can aggregate to any size company to determine its monitoring costs. For example, in onshore natural gas transmission, a compressor station as a facility was modeled at the three different model size levels. Any onshore natural gas transmission company can determine its monitoring costs by assigning the model facility costs to its facilities that are closest to the appropriate level of the model facility. To determine the national cost from each segment, we assigned a model facility cost that best fit the facility based on its emissions profile. Next, we summed the costs assigned to each facility in the segment to produce the total national cost in each segment. Section 4.5 of this document describes the calculation in further detail.

Facilities in onshore production, however, are defined as all petroleum or natural gas equipment associated with all petroleum or 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. There is much larger variation in facilities by this definition, so developing model "small", "medium", and "large" facilities is unintuitive and impractical. In this case, equipment activity was estimated at the field-level and aggregated to the national level, then apportioned to individual operators in basins by production rates.

Table 4-2 Number of Facilities Reporting by Threshold and Sector

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Segment	Threshold			
	1,000	**10,000**	**25,000**	**100,000**
Onshore Production	10,604	2,413	1,232	466
Natural Gas Processing	566	396	289	130
Transmission Compressor Stations	1,695	1,443	1,145	433
Natural Gas Storage	347	200	133	36
Liquefied Natural Gas Storage	54	41	33	4
Liquefied Natural Gas Terminals	5	4	4	4
Offshore Production	1192	184	58	4
Local Distribution Companies	594	203	143	66

Labor Costs. To evaluate labor costs, it was necessary not only to determine the amount of time required for all of the tasks associated with monitoring, but also to determine who will perform each task. For the sake of this analysis, four labor categories were used. Assigning labor hours for all cost elements was based on expert judgment. When assigning hours, the size of the facility and role of the labor categories were taken into consideration.

The labor costs associated with performing the actual annual monitoring were omitted from the loaded labor rates. For these costs, it was assumed that all labor will be performed by middle managers, junior engineers, and senior operators. Middle managers are assumed to spend a total of 2 hours overseeing the monitoring process per quarter, but are assumed not to perform any of the monitoring. It was assumed that junior engineers and contracted technicians will do all of the monitoring, except in cases where senior operators will log any activity data required to estimate emissions over the course of the quarter. Several equipment types are common between different onshore segments and different facility sizes, but the actual monitoring time typically will not change per equipment unit. For example, centrifugal compressor seals are found in all onshore segments (assuming some gas gathering is operated by producers), except for natural gas distribution. Measuring centrifugal compressor seal degassing vents for leaks was assumed to take 1 hour onshore, and that will not change by segment or facility size. What changes is the number of centrifugal compressors located at facilities of different sizes. Thus, a series of universal assumptions about onshore monitoring times were created. These were multiplied by the emissions source counts assigned to each of the model facilities to determine the required labor hours. Once the labor hours were calculated, by category, for each of the cost elements, they were multiplied by the associated labor rates to estimate labor costs per facility. The only remaining facility costs are due to the annualized capital costs and travel, lodging, and shipping to conduct the actual emissions monitoring.

Table 4-3 below presents labor cost numbers aggregated across all segments for Subpart W. These data are aggregated from individual tables for each segment. Except for onshore production, each segment has a table for small, medium and large facilities; onshore production is calculated at the field-level, then apportioned to basin-levels as discussed above.

Capital and O&M Costs. The capital costs related to monitoring emissions and archiving of information consists of purchasing equipment for emissions detection (or the portion of contractor purchases of equipment is apportioned to all its customers), emissions measurement, and information storage. All costs are reported in 2006 U.S. dollars and annualization was assumed over an equipment life of five years with a seven percent interest rate. Fugitive emission monitoring does not have time-tested standards and fugitive emission streams typically are not clean gas. For example, a centrifugal compressor wet seal degassing vent will contain fine droplets of seal petroleum with the gas. A five-year equipment life was chosen to be conservative in cost estimates, opposed to the ten-year equipment life associated with long-standing, proven practices of measuring clean fuel streams assumed in the stationary combustion section.

Table 4-4 shows the capital and operation and maintenance costs at the 25,000 metric ton threshold for the aggregated Subpart W segments, less onshore production. The disparity in first year capital costs stems from the fact that each of the onshore segments that use compressors as part of normal operations are required to pay for a one-time flow measurement port installation on compressor seal degassing vents. This assumes that there will be no disruption in the operations since the port can be installed when the compressor is either in standby mode or under maintenance. Hence no adjustment is made for production or operational loss. First year labor costs include the labor required for registration, creating a monitoring plan, and general planning procedures that are required only in the first year of compliance. The “subsequent year” cost is a truer reflection of actual average costs over time.

As mentioned, a different approach was taken to determine labor cost for the onshore production segment. Unlike the previous segments, onshore production labor costs were estimated by scaling up field-level labor hours, displayed in Table 4-12, to a national scale and then apportioned by individual operator production rates. This approach was chosen over categorizing the operators by small, medium, and large because of the variety of operations present between operators in the onshore production segment. For this reason, the labor costs are not shown for the onshore production segment like in Table 4-3 and Table 4-4. However, the average operational and maintenance costs for the onshore production segment are shown separately in the bullets below each table.

Stationary Combustion Costs. Stationary combustion emissions occur in petroleum and natural gas systems primarily through natural gas used to drive compressor engines. Additional fuel is used to power drilling rigs (diesel) and for process heaters and boilers, glycol dehydrators, and some acid gas removal reboilers. Combustion emissions are included for the purposes of determining if Subpart W thresholds are met, however combustion emissions are reported separately under Subpart C.

This analysis includes the cost of incremental combustion reporting and combustion emissions above those that exceed the Subpart C threshold alone and would therefore already be reporting under Subpart C. EPA applied the IPCC system Tier 1 methodology, known as

Default Heat Content, to estimate the combustion emissions. The Tier 1 approach bases estimates on a fuel-specific default CO_2 emission factor, a default heat content, and the annual fuel consumption from company records.[15] To estimate combustion emissions from compressor engines—the primary combustion application in Subpart W—only one emission factor was required per facility because the natural gas used for combustion is taken from one pipe of common fuel quality. Consequently the cost for monitoring fuel quality is relatively small even if there are multiple compressors at the facility.

Table 4-3 Subpart W Petroleum and Natural Gas Systems: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Senior Management ($101.31/hr)		Middle Management ($88.79/hr)		Junior Engineer/ or Technician ($71.03/hr)		Senior Operator ($63.89/hr)			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	0.80	0.08	3.31	0.21	8.82	0.74	4.18	0.35	$1,268	$103
QA/QC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0	$0
Recordkeeping	0.18	0.18	0.29	0.29	3.05	3.01	0.62	0.62	$301	$296
Sampling and analysis (calculations)	0.00	0.00	2.00	2.00	37.10	30.37	0.00	0.00	$2,813	$2,334
Reporting	0.06	0.04	1.53	1.32	4.83	4.41	15.92	15.36	$1,502	$1,416
Total	**1.04**	**0.31**	**7.12**	**3.82**	**53.81**	**38.52**	**20.72**	**16.33**	**$5,884**	**$4,150**

Onshore Production Labor Costs per Year per Reporting Unit/Facility:

- First Year: $21,877
- Subsequent Years Average: $6,709

[15] The final MRR used the IPCC Tier concept to estimate combustions emissions (74 FR 56260, October 30, 2009). See EPA-HQ-OAR-2008-0508-0004, U.S. EPA, Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases, January 30, 2009, for more information about the IPCC Tier methodology (pgs 10-15).

Table 4-4 Subpart W Petroleum and Natural Gas Systems: Capital and O&M Costs (2006$)

	Cost Categories				Capital and O&M Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)	$ 12,549	5	$ 8,615	N/A	$8,615	$8,615
Performance testing	[a]	[a]	[a]	[a]	[a]	[a]
Recordkeeping	$ 86	5	$21.09	N/A	$21	$21
Travel	N/A	N/A	N/A	$837.03	$837	$837
Total	**$12,635**	**N/A**	**$ 8,636**	**$837.03**	**$ 9,473**	**$ 9,473**

[a]Performance testing is not required under Subpart W so no costs are entered.

Onshore Production Capital and O&M Cost per Unit/Facility:

- First Year: $22,490
- Subsequent Years Average: $6,982

Table 4-5 Subpart W Petroleum and Natural Gas Systems: Combustion Costs (2006$)

	Cost Categories				Total Reporting Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)	$3,500	10	$500	$1,700	$2,200	$2,200
Total	**$3,500**		**$500**	**$1,700**	**$2,200**	**$2,200**

4.4 Summary Results: Subpart W—Petroleum and Natural Gas Systems

For each segment in the petroleum and natural gas industry identified as amenable to a reporting program, four thresholds were considered for emissions reporting as applicable to an individual facility; 1,000 metric tons of CO_2 equivalent (mtCO_2e) per year, 10,000 mtCO_2e, 25,000 mtCO_2e, and 100,000 mtCO_2e. A threshold analysis was then conducted on each segment to determine which level of threshold was most suitable for each industry segment. CH_4, CO_2, and N_2O emissions from each segment were included in the threshold analysis.

Table 4-6 shows the number and share of entities and emissions covered by the Subpart W supplemental proposed rule. The table shows that at lower thresholds, a higher number and share of facilities and emissions are covered by the rule. As the threshold increases, smaller numbers and shares of facilities and emissions are affected. Of significant note, 83 percent of emissions are covered at the selected 25,000 metric ton CO_2e threshold. Further, both total emissions and covered emissions include incremental combustion emissions not triggered by the threshold of Subpart C alone. Again, all combustion emissions are reported under Subpart C, but the 25,000 metric ton threshold is determined by all GHG emissions reportable under all subparts.

Table 4-6 Subpart W Facilities and Emissions Covered by Proposed Rule

Threshold	Number of Entities	Number of Facilities Covered	Percent of Facilities Covered	Total Emissions (Million $mtCO_2e$) Year)	Covered Emissions (Million $mtCO_2e$) Year)	Percent of Emissions Covered
1,000 Threshold	35,724	15,057	42%	425	415	98%
10,000 Threshold	35,724	4,884	14%	425	380	90%
25,000 Threshold	35,724	3,037	9%	425	351	83%
100,000 Threshold	35,724	1,143	3%	425	273	64%

Detailed Threshold Analysis. For each segment, a threshold analysis was conducted to determine how many of the facilities in the segment exceed the various reporting thresholds, and the total emissions from these affected facilities. This analysis was conducted considering vented and fugitive CH_4 and CO_2 emissions, and combustion CH_4, CO_2, and N_2O emissions. The vented and fugitive emissions estimates available from the U.S. GHG Inventory were used in the analysis. However, the emissions estimates for four sources—well venting for liquids unloading, gas well venting during well completions, gas well venting during well workovers, and centrifugal compressor wet seal degassing venting—from the U.S. GHG Inventory were replaced with revised estimates, which are described in Appendix B of the TSD.

Combustion emissions from processing, transmission, underground storage, LNG storage, and LNG import and export terminals were estimated using gas engine methane emissions factors available from GRI/EPA 1996, back calculating the natural gas consumption in engines, and finally applying a CO_2 emissions factor to the natural gas consumed as fuel. N_2O emissions were calculated similarly. In the case of offshore petroleum and natural gas production platforms combustion emissions are already available from the GOADS 2000 study analysis and hence were directly used for the threshold analysis. In addition to gas engines, combustion emissions from reboilers on glycol dehydrators, acid gas removal amine regeneration, diesel engines on drilling rigs, and heater-treaters were estimated for onshore production. The volume of fuel gas required by regular operation of a glycol dehydrator was calculated per volume of dehydrator input; then the API Compendium combustion emission factors for natural gas were applied to facilities' fuel gas use based on their gas production rates. The same assumptions were made to calculate combustion emissions from acid gas removal amine regeneration heaters. Drilling rigs were assumed to operate two 1,500-horsepower diesel engines per well drilled, and assuming it requires 90 days to drill and complete one unconventional (i.e. those requiring hydraulic fracturing) gas well and 30 days to drill and complete one conventional gas or petroleum well. The API Compendium combustion emission factors for diesel engines were used to calculate the emissions. The total drilling emissions for the nation were calculated based on the number of drilling rigs in service, then apportioned to each basin by throughput.

The threshold analysis for the rule includes fugitive, vented, and combustion emissions and requires estimation of all emissions at a facility level. As a result, the total emissions from the threshold analysis do not necessarily match the U.S. GHG Inventory for all segments of the petroleum and natural gas industry. A detailed discussion on the threshold analysis is available in the TSD (EPA-HQ-OAR-2009-0923).

The general rationale for selecting a reporting threshold is to identify a level at which the incremental emissions reporting between thresholds is the highest for the lowest incremental increase in number of facilities reporting between the same thresholds. This would ensure maximum emissions reporting coverage with minimal burden on the industry.

Table 4-7 summarizes the national costs and costs per representative entity for each threshold. The first five columns report subsets of costs, including costs associated with processes (labor, annualized capital, and operating and maintenance costs), costs associated with stationary combustion, and costs associated with reporting and recordkeeping. The final four columns report total national costs and total per-entity costs for the first year and for subsequent years.

Table 4-7 Summary of Costs and Costs per Representative Entity by Threshold (Million 2006$)

Threshold	First Year Process Costs	Subsequent Year Process Costs	First Year Combustion Costs	Subsequent Year Combustion Costs	Reporting and Record-keeping Costs*	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
1,000 Threshold	$156.6	$66.2	$29.0	$29.0	NA	$187.6	$0.01	$97.2	$0.01
10,000 Threshold	$73.0	$29.0	$7.6	$7.6	NA	$82.6	$0.02	$38.6	$0.01
25,000 Threshold	$56.0	$21.4	$3.9	$3.9	NA	$59.9	$0.02	$25.3	$0.01
100,000 Threshold	$34.3	$11.6	$1.0	$1.0	NA	$36.4	$0.03	$13.7	$0.01

* These costs are included in Process Costs.

Note that year one costs are significantly higher than the subsequent year average costs. This is due to the following reasons:

- Initial start-up costs include labor and capital associated with establishing modifications to enable ongoing quantification of key emissions sources. This includes costs to install measurement ports in compressor and well vents and purchase equipment.
- For onshore production, reporting occurs annually but the measurement of key sources is updated every two years.

Subsequent year costs are therefore reported as an average cost for years following year one. As described in Table 4-7 above, at lower thresholds, a larger number of facilities in each subpart are covered by the rule, and thus incur costs. For this reason, the total national costs, and total costs by cost subset, decline as the threshold increases from 1,000 mtCO_2e to 10,000 mtCO_2e, to 25,000 mtCO_2e, and finally to 100,000 mtCO_2e. Cost per representative entity for a particular segment generally declines for Subpart W as the threshold increases.

4.5 Detailed Cost Assumptions: Subpart W—Petroleum and Natural Gas Systems

The assumptions below are the basis for the determination of the costs noted in Section

STEP 1: Model Facility Development

For each of the industry segments, with the exception of onshore production, operations had to be divided into single units or model facilities at three levels; "small," "medium," and "large." The monitoring costs were then developed per size level of a model facility. A model facility of a given level can be defined as the most convenient and logical unit with appropriate emissions source counts that can aggregate to any size company to determine its monitoring costs. For example, in onshore natural gas transmission, a compressor station as a facility was modeled at the different levels. Any transmission company can determine its monitoring costs by assigning model facility costs to its facilities that are closest to the appropriate level of the model facility. Facilities in onshore production, however, are defined as operators reporting all equipment covered by the proposed rule at the basin-level. There is much larger variation in facilities by this definition, so developing model "small," "medium," and "large" facilities is unintuitive and impractical. In this case, equipment activity was estimated at the field-level and aggregated to the national level, then apportioned to individual operators in basins by production rates.

For each of the sources designated for monitoring, both equipment and component counts were determined to define individual model facilities, except as noted in onshore production. For onshore natural gas processing, onshore natural gas transmission, underground natural gas storage, LNG storage, import and export facilities and natural gas distribution, equipment and component counts for medium facilities were assigned the national average activity factors from the National Inventory, or the nearest reasonable integer value. In some cases, the uncertainty associated with the activity factors were used to determine the lower bound on equipment and component counts, and assigned to a "small" facility. Similarly, the upper bound on emissions source counts was assigned to a "large" facility. If illogical values, such as in the case of compressors in natural gas transmission compressor stations, resulted from the above methodology; expert judgment was used to correct the values; bounding the aggregated activity levels to that of the national inventory. In the case of offshore petroleum and natural gas production, MMS GOADS-2000 data analysis by EPA was used in the same fashion as the national inventories. In some cases, the uncertainty estimates were not applicable. For example, if the uncertainty is over 100%, it would predict a negative lower bound for emissions source counts. For these cases, expert judgment was used. Expert judgment was also used, where necessary, to adjust emissions source counts to reflect real world scenarios. Both equipment and component counts at facilities by segment and size are presented in the docket (EPA-HQ-OAR-2009-0923)

STEP 2: Determine Cost Elements

The total costs associated with complying with the proposed rulemaking were broken into five elements, each of which is described below. Additionally, these cost elements are considered in two ways: costs associated with start-up and recurring costs. Startup costs refer to a one-time cost associated with initiating the reporting process. Subsequent costs for reporting on an annual basis are less than the startup costs and are referred to as recurring costs.

1. Regulation compliance determination costs

    a. Start-up costs consist entirely of the labor necessary to study and review the regulations to assure compliance, gather data on the facility, and fill out any appropriate forms.

    b. Recurring costs will be small and consist entirely of labor expenses. Small amounts of time will be required for the company to stay aware of any updates to regulations and to alter the facility information to reflect any new equipment or facilities brought into operation or taken offline.

2. Monitoring costs

    a. Start-up monitoring costs consist of both labor and capital costs. Capital investment will be required for purchasing monitoring equipment. This capital cost will be accounted as annualized cost, on an annual basis. Labor will be required for product research for monitoring instruments before actual purchase. Before actual monitoring takes place, labor will have to be devoted to the development of a monitoring plan that will be used company-wide. Finally, selected employees will be trained on how to use the monitoring equipment.

    b. Recurring monitoring costs consist of labor, travel, and shipping of equipment. Each cycle, labor will be required to conduct detection and quantification of emissions, i.e., perform actual monitoring of emissions. Quantification may take place through direct measurement, use of engineering calculations and/or software, use of "leaker" emission factors for detected leaks, or use of component counts and population emission factors. For companies with multiple facilities, travel may be required for the monitoring team and/or the monitoring instruments may require shipping to multiple locations.

3. Reporting costs

    a. There will be no start-up reporting costs; reporting costs are applied uniformly across segments reporting to the rule.

    b. Recurring reporting costs consist of labor necessary to document collected emissions data from fugitive emissions monitoring and to submit the official report in each cycle (i.e., annually).

4. Archiving and recordkeeping costs

    a. Start-up archiving and recordkeeping costs consist of labor and annualized capital purchase of storage space. For archiving reports and associated working documents, physical storage system such as a file cabinet, and electronic storage system such as an external hard drive, will be required.

    b. Recurring archiving and recordkeeping costs consist entirely of labor necessary to adequately archive each cycle's report and associated working documents.

5. Auditing costs

    a. There is no start-up cost associated with auditing.

    b. Recurring auditing costs consists of labor required to validate to the EPA results from the monitoring of emissions and the follow-up of rectifying any weaknesses found through the audit. The EPA audit is assumed to occur once in several years, not on an annual basis.

STEP 3: Analyze Proportion of Facilities in Different Model Facility Levels

To classify the facilities into different sizes, total combustion, fugitive and vented CO_2, N_2O, and CH_4 emissions from individual facilities, expressed in CO_2e, were rank listed in an ascending order. Cumulative emissions for the facilities were calculated by summing the emissions of the individual facility to those of the facilities before it in the ascending list. The cumulative emissions, in combination with the total emissions from all facilities, were used to assign facilities to the small, medium, and large category.

$$Percentile(\%) = \left(\frac{CumulativeEmissions}{TotalEmissions} \right)$$

The facilities that accounted for the first 33% of the emissions nationally in the ranked list were identified as a small facility. The facilities that accounted for national emissions greater than 33 percent but less than 67 percent in the ranked list were identified as a medium facility. The facilities that accounted for national emissions over 67 percent in the ranked list were identified as a large facility. Table 4-8 indicates the data sources used to apportion total GHG emissions to individual facilities, and the number of facilities that fall into each category per segment.

STEP 4: Assigning Costs to Cost Elements

Assigning costs to each of the cost elements was completed in three steps:

1. Determine labor categories and associated labor rates,
2. Allocate responsibilities to labor categories to estimate labor hours, and
3. Determine annualized capital costs and operation & maintenance (O&M) costs for each of the cost elements.

These steps are described in further detail below.

Table 4-8 Allocation of Facilities to Model Types

Segment	Data Source	Small Facilities	Medium Facilities	Large Facilities
Offshore Petroleum and Natural Gas Production				
Facility Percentile	MMS GOADS Report & Lasser 2006	0–33%	34%–67%	68%–100%
Facility Count	MMS GOADS Report & Lasser 2006	3,036	191	8
Mean Emissions (tCO_2e)	This Analysis	1,430	22,733	483,806
Operator/Company [2]	Not estimated			
Onshore Petroleum and Natural Gas Production[3]				
Facility Percentile	Lasser 2006	0–33%	34%–67%	68%–100%
Facility Count	Lasser 2006	10,192	349	63
Operator/Company	Lasser 2006	—	—	—
Mean Emissions (tCO_2e)	This Analysis	3,175	262,247	1,479,683
Onshore Natural Gas Processing				
Facility Percentile	API Processing Report	0–33%	34%–67%	68%–100%
Facility Count [1]	API Processing Report	486	65	15
Operator/Company	API Processing Report	166	28	10
Mean Emissions (tCO_2e)	This Analysis	36,531	275,486	1,137,595
Onshore Natural Gas Transmission				
Facility Percentile	FERC	0–33%	34%–67%	68%–100%
Facility Count	FERC	1,314	374	255
Operator/Company	FERC	147	46	27
Mean Emissions (tCO_2e)	This Analysis	22,114	97,050	209,073
Natural Gas Underground Storage				
Facility Percentile	EIA	0–33%	34%–67%	68%–100%
Facility Count	EIA	325	50	22
Operator/Company	EIA	102	37	17
Mean Emissions (tCO_2e)	This Analysis	12,386	82,081	183,671
LNG Storage				
Facility Percentile	GTI	0–33%	34%–67%	68%–100%
Facility Count	GTI	141	13	3
Operator/Company	GTI	141**	11	3
Mean Emissions (tCO_2e)	This Analysis	17,639	61,135	243,877
LNG Import and Export				
Facility Percentile	FERC	—	0–100%	—
Facility Count	FERC	—	5	—
Operator/Company	Not estimated			
Mean Emissions (tCO_2e)	This Analysis	—	174,643	—
Natural Gas Distribution				

Facility Percentile	DOT	0–33%	34%–67%	68%–100%
Facility Count	DOT	1,361	50	16
Operator/Company	DOT	1,268	49	16
Mean Emissions (tCO_2e)	This Analysis	5,840	167,066	536,719

1 MMS 2007 statistics reports 3,923 offshore platforms and 139 operators. No data are available for individual offshore platforms and their respective operators.

2 Assumed one facility per company; no data available for small plants

3 The onshore production burden analysis was conducted using a hybrid approach. Capital costs and some recurring O&M costs were assigned on a small, medium large basis; however, the majority of the recurring O&M costs were determined by apportioning nationwide costs by individual operator throughput.

4.5.1 Determining Labor Categories

To evaluate labor costs, it was necessary to not only determine the amount of time required for all of the tasks associated with monitoring, but also to determine who will perform each task. For the sake of this analysis, five labor categories were used, as shown in Table 4-9.

Table 4-9 Labor Categories and Hourly Rates

Labor Category	Description	Loaded Hourly Rate
Senior Manager	Oversees work at a high level. Is the final authority on all reporting requirements.	$101.31/hour
Middle Manager	Oversees junior engineer's progress and reports; also interacts with senior manager. Does not gather information, write reports, or perform monitoring.	$88.79/hour
Junior Engineer	Conducts monitoring of emissions sources. Interfaces between middle manager and senior operator to collect information and complete reports.	$71.03/hour
Senior Operator	Primarily interfaces with junior engineer to collect facility information and assist with initiating the reporting process and reporting. Sometimes logs data used in the monitoring process.	$63.89/hour
Technician	Contracted by the company to perform basic leak detection activities.	$55.20/hour

1 All data from U.S. Department of Labor, Bureau of Labor Statistics, National Compensation Survey - Compensation Cost Trends, Employer Cost for Employee Compensation (ECEC), Customized Tables, as of March 11, 2003.

These labor rates originate from an analysis of loaded hourly rates for goods and producing private establishments at the end of 2007, shown in

Table 4-10 below. Since the petroleum and natural gas industry pays comparatively high to other industries, the top four non-lawyer categories were used to be conservative in this approximation. Specifically, the labor rate of senior managers were assumed to be that of refinery mangers, middle manager labor rates were assumed to be that of electricity managers, junior engineer labor rates were assumed to be that of industrial managers, senior operator labor rates were assumed to be that of refinery engineers/technicians, and contracted technician labor rates were assumed to be that of industrial engineer/technician category.

Table 4-10 Loaded Hourly Rates for Goods Producing Private Establishments

Labor Category	Loaded Hourly Rate ($/hour)
Electricity Manager	$88.79
Refinery Manager	$101.31
Industrial Manager	$71.03
Lawyer	$101.00
Electricity Engineer/Technician	$60.84
Refinery Engineer/Technician	$63.89
Industrial Engineer/Technician	$55.20
Administrative Support	$29.65

1 All data from U.S. Department of Labor, Bureau of Labor Statistics, National Compensation Survey - Compensation Cost Trends, Employer Cost for Employee Compensation (ECEC), Customized Tables, as of March 11, 2003.

4.5.2 Allocating Responsibilities

Assigning labor hours for all cost elements was based on expert judgment. When assigning hours, the size of the facility and role of the labor categories were taken into consideration. Table 4-11 summarizes these roles.

Table 4-11 Responsibilities for Regulation Compliance by Labor Category

Cost Element	Senior Management	Middle Management	Junior Engineer	Senior Operator	Per Facility/ Per Company*
Facility data	To review reporting documentation/ systems and facility data	To review reporting documentation/ systems and facility data	To initiate reporting process and prepare facility data	To prepare and review reporting process documentation and facility data	Per facility
Regulation review	To review the new regulations	To review the new regulations	To examine and identify potential new regulations	To review the new regulations identified and determine their applicability	Per company
Plan development	To review the monitoring plan	To review the monitoring plan	To develop a monitoring plan	To develop and review the monitoring plan	Per company
Equipment purchase	To approve the equipment purchase	To review the equipment to be purchased	To identify and purchase the equipment	To review the equipment to be purchased	Per company
Start-up/ training		To review training plan	To acquire training	To provide and acquire training	Per facility
Data documentation	To review the reporting documentation	To prepare and complete the reporting documentation	To prepare reporting documentation	To prepare and complete reporting documentation	Per facility
Report submission		To ensure the completion of the reporting documentation	To submit the report		Per Facility

Archiving reports			To archive the reporting documentation	To archive the reporting documentation	Per facility
Audit	To review the audit results	To review the audit results	To assist and provide information on EPA audits		Per facility
Audit follow-up	To review the audit follow-up results and approve corrective measures	To review the audit follow-up results and review corrective measures	To determine corrective measures from EPA audit	To assist in determining corrective measures from EPA audit	Per facility

* Some activities only have to be done at the company level, with information and/or equipment shared among facilities of the company.

The labor costs associated with performing the actual annual monitoring were omitted from the table above. For these costs it was assumed that all labor will be performed by middle managers, junior engineers, senior operators, and contracted technicians. The assumed responsibilities and associated hours are organized in Table 4-12.

Additionally, several pieces of equipment are common among different onshore segments and different facility sizes, but the actual monitoring time typically will not change per equipment unit. The series of universal assumptions about onshore monitoring times are also provided in Table 4-12.

Table 4-12 Responsibilities for Onshore Monitoring and Allocation of Labor Hours

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	**Quantification**	**Applicable Segments**
Processing Facility Fugitive emissions			
Technician	Conduct fugitive emissions detection survey (8 hours/ small facility, 12 hours/ medium facility, or 16 hours/large facility)		Processing
Junior engineer		Estimate emissions using leaker factors (2 hours/facility)	Processing
Middle Management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (1 hour/ reporting period)	Processing
Transmission Facility Fugitive emissions			
Technician	Conduct fugitive emissions detection survey (17 hours/ small facility, 19 hours/		Transmission

	medium facility, and 19 hours/large facility)		
Junior engineer		Estimate emissions using leaker factors (2 hours/ small facility, 2 hours/ medium facility, and 3 hours/ large facility)	Transmission
Middle Management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (1 hours reporting period)	Transmission
Underground Storage Facility Fugitive emissions			
Technician	Conduct fugitive emissions detection survey (47 hours/ small facility, 53 hours/ medium facility, and 63 hours/large facility)		Storage
Junior engineer		Estimate emissions using leaker factors (2 hours/ small facility, 3 hours/ medium facility, and 2 hours/ large facility)	Storage
Middle Management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (2 hours/ reporting period)	Storage
LNG Import/Export Terminal Fugitive emissions			
Technician	Conduct fugitive emissions detection survey (43 hours/ facility)		LNG Import and Export Facilities
Junior engineer		Estimate emissions using leaker factors (2 hour/ facility)	LNG Import and Export Facilities
Middle Management	Oversee part of the detection process and review results (2 hours/reporting period)	Oversee part of the measurement process and review results (1 hour/ reporting period)	LNG Import and Export Facilities
LNG Storage Facility Fugitive emissions			
Technician	Conduct fugitive emissions detection survey (12 hours/ small facility, 19 hours/ medium facility, and 24 hours/large facility)		LNG Storage
Junior engineer		Estimate emissions using leaker factors (2 hours/ small facility, 2 hours/ medium facility, and 3 hours/ large facility)	LNG Storage
Middle Management	Oversee part of the detection process and review results (1	Oversee part of the measurement process and	LNG Storage

	hour/reporting period)	review results (1 hour/ reporting period)	
LDC Above Grade M&R Station Fugitive emissions			
Technician	Conduct fugitive emissions detection survey (1 minute/ station)		Distribution
Junior engineer		Estimate emissions using leaker factors (8 hours/ reporting period)	Distribution
Middle Management	Oversee part of the detection process and review results (2 hours/reporting period)	Oversee part of the measurement process and review results (1 hour/ reporting period)	Distribution
Reciprocating Compressor Fugitive Emissions			
Technician	Check unit for fugitive emissions (1 hour/ compressor)		Processing
Technician	Check unit for fugitive emissions (1.5 hours/ compressor)		Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Junior engineer		Apply emission factors or leaker factors (time accounted for by facility fugitives quantification)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Reciprocating Compressor Rod Packing Emissions			
Technician	Check packing open-ended lines for emissions (10 minutes/ compressor)		Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Junior engineer		Measure rod packing emissions (1 hour/ compressor)	Onshore Production, Processing
Junior engineer		Measure rod packing emissions (2 hours/ compressor)	Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Centrifugal Compressor Fugitive Emissions			
Technician	Check unit for fugitive emissions (1 hour/ compressor)		Processing
Technician	Check unit for fugitive emissions (2 hours/ compressor)		Storage, LNG Import and Export Facilities
Technician	Check unit for fugitive emissions (2.5 hours/ compressor)		LNG Storage
Centrifugal Compressor Seals			
Junior engineer	Check unit for fugitive emissions (1 hour/ compressor)	Measure degassing vent emissions (1 hour/ compressor)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities

Unconventional Well Completion and Workover			
Junior engineer		Measure flowback from completion or workover (8 hours/ field)	Onshore Production
Well Liquid Unloading			
Junior engineer		Measure flow from well blowdown (4 hours/ basin)	Onshore Production
Acid Gas Removal Vent Stacks			
Junior engineer		Perform simulation runs (10 minutes/AGR Vent)	Processing
Kimray Pumps			
Junior engineer		Accounted for in station fugitive emissions – certain portion of time is assumed to be for engineering estimation of sources	Onshore Production, Processing, Transmission, Storage
Dehydrator Vent Stacks			
Junior engineer		Collect data and perform simulation runs, accounted for in fugitive emission data collection (1 hour)	Onshore Production
Junior engineer		Collect data and perform simulation runs (10 minutes/dehydrator vent)	Processing
Junior engineer		Accounted for in station fugitive emissions – certain portion of time is assumed to be for engineering estimation of sources	Transmission, Storage
Wellhead Fugitive Emissions			
Junior engineer		Apply emission factor – accounted for in station fugitives	Onshore Production, Storage
Storage Tanks			
Junior engineer		Collect data and perform simulation runs (1 hour/ tank)	Onshore Production, Processing, Transmission
Coal Bed Methane Water Production			
Junior engineer		Water sampling per basin four times per year where where it is used for EOR – time accounted for in fugitives data collection	Onshore Production
Gathering Pipelines			
Junior engineer		Estimate emissions using population emission factor – time accounted for in station fugitives	Onshore Production, Processing, Transmission, Distribution

Natural Gas Distribution Pipelines			
Junior engineer		Estimate emissions using population emission factor – time accounted for in station fugitives	Distribution
Below Grade Metering & Regulating Stations			
Junior engineer		Estimate emissions using population emission factor – time accounted for in station fugitives	Distribution
Well Testing			
Junior engineer		Perform emissions calculation with GOR measurement (1 hour/ well)	Onshore Production
Natural Gas Pneumatic Bleed Devices			
Junior engineer		Apply emission factor – accounted for in station fugitives	Onshore Production, Processing, LNG Storage, LNG Import and Export Facilities, Distribution
Junior engineer	Check devices and take inventory of brand/models (8 minute/pneumatic device)	Calculate bleed rates based on use and design (22.5 minutes/pneumatic device)	Transmission, Storage
Flare Stacks			
Junior engineer	Collect data for emission estimate (10 minutes/ station)	Estimate emissions using emission factor (10 minutes/ station)	Processing
Junior engineer		Apply emission factor – accounted for in station fugitives	Onshore production
Blowdown Vent Stacks			
Junior engineer		Perform emissions calculation (8 minutes/ station)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Junior engineer		Accounted for in station fugitives	Distribution

Table 4-12 does not include equipment monitoring on offshore petroleum and natural gas production facilities. Offshore production platforms are proposed to use data already collected for MMS GOADS to estimate greenhouse gas emissions from their operations. Specifically, the MMS GOADS program requires the monitoring of GHG emissions from platforms in the Gulf of Mexico Federal waters. Facilities under this proposed supplemental rulemaking are required to report the same emissions data calculated by the GOADS Program. Hence these platforms have minimal additional reporting burden. The cost burden model assumes that this requires 30 minutes per platform.

However, platforms that are in State waters or in Federal waters outside the Gulf of Mexico, GHG emissions will have to be estimated using the MMS GOADS procedures. EPA estimates the reporting cost for non-GOADS platforms to be $5,000 for first year of reporting.

Once the labor hours were calculated, by category, for each of the cost elements, they were multiplied by the associated labor rates to estimate labor costs per facility. The only remaining facility costs are due to the annualized capital costs and travel, lodging, and shipping to conduct the actual emissions monitoring.

4.5.3 Capital Cost Annualization and O&M Costs

The capital costs related to monitoring emissions and archiving of information consists of purchasing equipment for emissions detection, emissions measurement, and information storage. All costs are reported in 2006 U.S. dollars and annualization was assumed over an equipment life of 5 years with a 7% interest rate. From these factors, a capital recovery factor of 24% was calculated using the formula provided below:

$$CRF = \frac{r(1+r)^n}{(1+r)^n - 1}$$

where CRF is the capital recovery factor, r is the interest rate, and n is the life expectancy in years. Table 4-13 below summarizes the annualized capital costs associated with the monitoring program. Additionally, the table describes the annual costs of travel, lodging, and shipping—the only other non-labor costs related to the monitoring program.

Table 4-13 Monitoring Program Compliance Capital Costs and Other O&M

Element	Capital Cost	Annualized Capital Cost
Archiving		
Capital costs	Cost of archiving material per facility assumes cost of 1 file cabinet, 4-drawer vertical from Office Depot™ ($140), and 1 hard drive for data storage from Seagate™ ($95)	$57
Monitoring		
Equipment purchase	Screening equipment is represented by a nominal $100,000 cost for an infrared camera. It is assumed to be purchased by the contractors who will pass on the costs to as many facilities as they can provide a service each year.	$24,389
Measurement		
Equipment purchase	Hotwire anemometers are required for compressor seal vents. It is assumed that the hotwire anemometer, a vinyl carrying case, an AC adapter, data acquisition software, and anemometer electronic data logger will be purchased.	$206
Traveling	Cost of traveling for an engineer to a facility from the home facility (therefore n-1 facilities to visit). Assuming travel cost is $0.485/mile, $150/night for overnight stay, $100/shipment for shipping equipment, and $100 per diem.	$0–$10,449*

* Annual travel costs are highly variable depending on the facility type, proximity, and ownership structure. Annual travel costs are estimated to vary from $0 to $10,449.

As shown in Table 4-13, the fugitive and vented emissions detection methods vary depending on the size of the company and its facilities. In the case of companies with small operations and few facilities, the costs passed on by contractors will be spread over many facilities.

Each facility is assumed to purchase an adequate flow meter to measure the emission rates from compressor seal vents either at the pipe end if accessible, or a flow measurement port installed at a suitable location capturing all vent emissions.

With the equipment costs per company determined, the final step was to divide company capital and O&M costs amongst individual facilities owned by a typical company.

Step 3 above provided the proportion of facilities that fall in the small, medium, and large categories. By determining the companies that fall in the three categories, the average number of “small,” “medium,” and “large” facilities per company was determined. To convert the annualized capital costs and equipment purchases, the costs per equipment were attributed to the number of facilities that can be serviced (as determined the number of labor hours required to monitor a facility) each year, as shown in the equation below:

$$\frac{\$AnnualCapital}{Facility} = \left(\frac{\$AnnualCapital}{Equipment} \times \frac{\#ofEquipment}{Contractor} \right) \div \left(\frac{FacilitiesServiced}{Contractor} \right)$$

The travel, lodging, and shipping costs associated with monitoring several facilities spread over large regions were calculated using the assumed costs in Table 4-13. Expert judgment based on the number of teams using equipment and the necessity of travel versus shipping between facilities was used to determine these costs.

STEP 5: Estimate per Facility Costs for Each Threshold Level

The total reporting costs across each segment were determined by assigning model facility costs (small, medium, and large) to individual facilities in the respective industry segments based on relative size and determining total costs from the entire segment. This was done for only those facilities that exceeded the reporting threshold. Average cost per facility was then determined by dividing the total segment costs by the number of facilities that exceeded the reporting threshold—small, medium, or large. In the case of onshore production, field-level monitoring costs were aggregated to the total national burden, then distributed to operators at the basin-level based on production rates.

SECTION 5
SUBPART W ANALYSIS OF REPORTING RULE OPTIONS

For petroleum and natural gas systems, Subpart W, as shown in Table 5-1, the total cost of the reporting rule to the Private Sector is estimated to be $59.9 million in the first year and $25.3 million in subsequent years (2006$). These costs include costs for vented and fugitive emissions and incremental combustion emissions triggered by the sum of process and combustion emissions exceeding the threshold. Fugitive and vented emissions alone are $56.0 million in year one and $21.4 million in subsequent years. They are based on the selected option, which includes an annual emissions-based threshold of 25,000 metric tons CO_2e for each facility and a hybrid of direct measurement and source-specific calculation methodologies. Section 3.2 provides more details about the selected option.

EPA estimates that for Subpart W, the public sector burden is $1.2 million per year. Approximately $0.5 million per year is for verification activities, and about $0.7 million per year is for program implementation and developing and maintaining the data collection system. Program implementation activities include, but are not limited to, developing guidance and training materials to assist the regulated community, responding to inquires from affected facilities on monitoring and applicability requirements, and developing tools to assist in determining applicability. In addition to total national costs for petroleum and natural gas systems, we also report average cost per metric ton to support additional analysis of the mandatory reporting programs. These costs are also shown on Table 5-1.

The initial year costs are higher due to initial program start up costs (primarily investment to secure equipment and install flow measurement ports in vent lines to allow measurement), and also because the first year requires that a number of key sources (well liquids unloadings, well workovers, compressor wet seal degassing vents, etc) be quantified. These sources are only required to be estimated bi-annually to mitigate long term burden. The cost per metric ton is about $0.17/metric ton in the first year, declining to an average of $0.07/metric ton in subsequent years.

Table 5-1 National Cost Estimates for Petroleum and Natural Gas Systems

Subpart W – Petroleum and Natural Gas systems	NAICS	First Year $Million 2006	First Year Million $MtCO_2e$	First Year $/Mt	Subsequent Years $Million 2006	Subsequent Years Million $MtCO_2e$	Subsequent Years $/Mt
Process Emissions	211, 486	$56.0	272.0	$0.21	$21.4	272.0	$0.08
Combustion Emissions		$3.9	79.1	$0.05	$3.9	79.1	$0.05
Private Sector, Total		$59.9	351.1	$0.17	$25.3	351.1	$0.07
Public Sector, Total		$1.2	351.1	$0.003	$1.2	351.1	$0.003
TOTAL		$61.1	351.1	$0.17	$61.1	351.1	$0.07

While the cost of the program is significant, there is in fact a large reduction in cost compared to the initial proposal stemming from the decision to use a hybrid approach to proposed measurement methodologies instead of direct measurement, which was the basis for the initial proposal for quantification of Subpart W emissions. In addition, the inclusion of onshore production and natural gas distribution into this segment significantly raises the total emissions which are covered in this analysis. Table 5-2 summarizes these changes based on year 1 costs for fugitive and vented emissions and Table 5-3 summarizes these changes based on subsequent year costs for fugitive and vented emissions.

Table 5-2 Vented and Fugitive Emissions Costs, Petroleum and Natural Gas Systems, First Year Estimates

Source Category	Emissions $MtCO_2e$		Million 2006$		$/Mt	
	Original	Revised	Original	Revised	Original	Revised
Original Six Segments*	85	94.3	$32.5	$26.7	$0.38	$0.28
Onshore Production	NA	154.9	NA	$27.7	NA	$0.18
Local Distribution	NA	22.7	NA	$1.6	NA	$0.07
Total	85	272.0	$32.5	$56.0	$0.38	$0.21

* Offshore production, natural gas processing, natural gas transmission, underground natural gas storage, LNG storage; LNG import/export.

Table 5-3 Vented and Fugitive Emissions Costs, Petroleum and Natural Gas Systems, Subsequent Year Estimates

Source Category	Emissions $MtCO_2e$		Million 2006$		$/Mt	
	Original	Revised	Original	Revised	Original	Revised
Original Six Segments*	85	94.3	$28.1	$11.8	$0.33	$0.13
Onshore Production	NA	154.9	NA	$8.6	NA	$0.06
Local Distribution	NA	22.7	NA	$1.0	NA	$0.04
Total	85	272.0	$28.1	$21.4	$0.33	$0.08

* Offshore production, natural gas processing, natural gas transmission, underground natural gas storage, LNG storage; LNG import/export.

5.1 Evaluating Alternative Options for Implementation of the Rule

The selected option was evaluated based on a cost-effectiveness analysis. For example, in selecting the emissions threshold, we compared the incremental emissions reported with the incremental costs (associated with the change in the facilities that would be required to report their emissions). Similarly, in selecting the reporting methodology option, we compared the change in uncertainty with the change in costs associated with different emission measurement/estimation techniques. The metrics used and the results of the cost-effectiveness analysis are discussed below.

In addition, the supplemental proposed rule requires the determination of onshore reporting to be done assuming that reporting parties report emissions and determine threshold on a basin level. In other words, owners or operators must report based on total emissions in all petroleum and natural gas production fields in a defined basin. EPA also examined an option to require companies to report on a field level basis. This alternative would affect the total emissions reported as well as cost, and is evaluated below.

Six alternative options were therefore evaluated for this analysis. While we believe these alternatives represent the most likely variations in the selected option, we recognize that in some cases particular interests may wish to evaluate more nuanced alternative options. To maintain transparency in the analysis, data necessary to conduct further alternative option analyses can be found in Section 4 of this document.

5.1.1 Analysis of Alternative Threshold Options

The threshold determines the number of entities required to report GHG emissions under Subpart W of the rule. The higher the threshold, the more entities that are excluded. It is assumed that the per-unit/entity cost does not change at different thresholds so that changes in the national cost estimates are driven by the number of reporting entities. The per-unit/entity costs outlined in Section 4 for Subpart W facilities, along with the estimates of numbers of covered entities at various thresholds, form the basis for this analysis. Two metrics are used to evaluate the cost-effectiveness of the emissions threshold. The first is the average cost per metric ton of emissions reported. The second metric for evaluating the threshold option is the marginal cost of additional reported emissions ($/metric ton CO_2e) relative to the option adopted in the final rule. To compute this metric, we compute the change in emissions reported by lowering or raising the threshold and divide this by the change in total reporting costs. Table 5-4Table 5-11 provides the cost-effectiveness analysis for the various thresholds.

Table 5-4 Summary of Threshold Cost-Effectiveness Analysis (First Year): Selected Hybrid Option is 25,000 metric tons CO_2e

Threshold ($MtCO_2e$)	Facilities Required to Report	Total Costs (Million 2006$)	Downstream Emissions Reported (Million $MtCO_2e$/ year)	Percentage of Total Downstream Emissions Reported	Average Reporting Cost (2006$/Mt)	Marginal Cost (2006$/Mt)
1,000	15,057	$187.61	415	98%	$0.45	$2.01
10,000	4,884	$82.59	380	90%	$0.22	$0.78
25,000	3,037	$59.90	351	83%	$0.17	$0.00
100,000	1,143	$36.38	273	64%	$0.13	($0.30)

The analysis also shows a marginal cost reduction of $0.30 per metric ton by moving from the selected threshold of 25,000 metric tons CO_2e to a higher threshold (100,000 metric tons); the total emissions covered decrease significantly—about 19 percent. Similarly, the marginal cost of moving the threshold from 25,000 to 10,000 increases $0.78 per metric ton and the emissions captured by increase 7 percent. Finally, the marginal cost of lowering the threshold from 25,000 to 1,000 yields the highest increase in marginal cost ($2.01 per metric ton), and increases the percentage of covered emissions by approximately 15 percent. Similar data is presented for subsequent years in Table 5-5.

Table 5-5 Summary of Threshold Cost-Effectiveness Analysis (Subsequent Years)

Threshold ($MtCO_2e$)	Facilities Required to Report	Total Costs (million 2006$ / year)	Downstream Emissions Reported ($MtCO_2e$)	Percentage of Total Downstream Emissions Reported	Average Reporting Cost (2006$/Mt)	Marginal Cost (2006$/Mt)
1,000	15,057	$97.18	415	98%	$0.23	$1.13
10,000	4,884	$38.62	380	90%	$0.10	$0.46
25,000	3,037	$25.30	351	83%	$0.07	$0.00
100,000	1,143	$13.66	273	64%	$0.05	($0.15)

Information on how costs are distributed across segments at each threshold is provided in Table 5-6 for thresholds of 1,000, 10,000, 25,000, and 100,000 metric tons CO_2e.

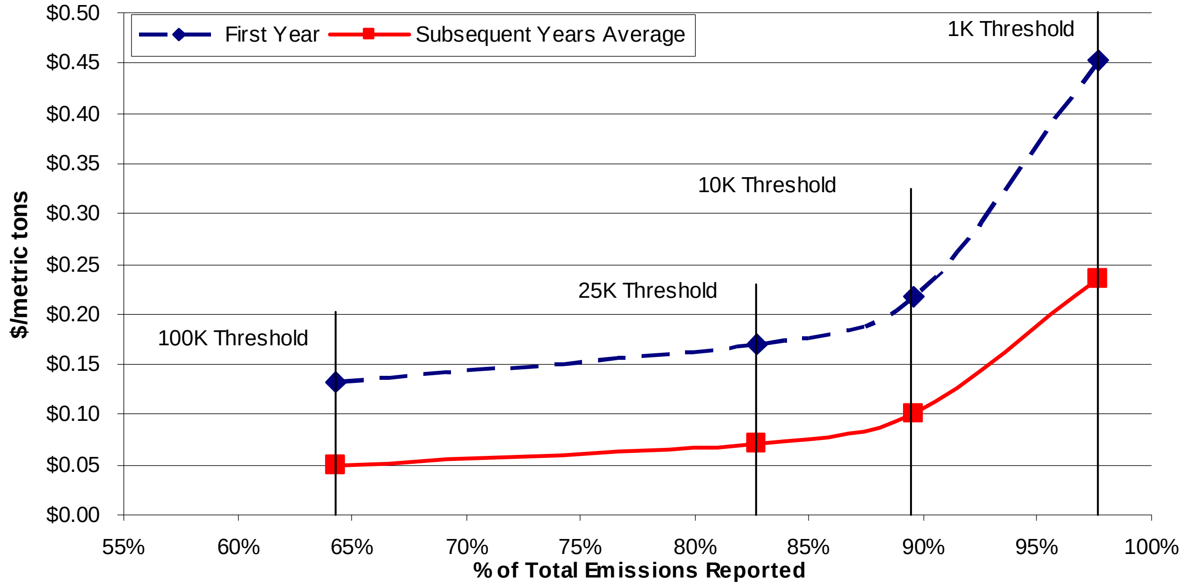
Table 5-6 Subpart W Cost Estimates by Threshold

Threshold	First Year		Subsequent Years	
	Million 2006$	$/Mt	Million 2006$	$/Mt
1,000 tCO_2e	$188	$0.45	$97.18	$0.23
10,000 tCO_2e	$82.59	$0.22	$38.62	$0.10
25,000 tCO_2e	$59.90	$0.17	$25.30	$0.07
100,000 tCO_2e	$36.38	$0.13	$13.66	$0.05

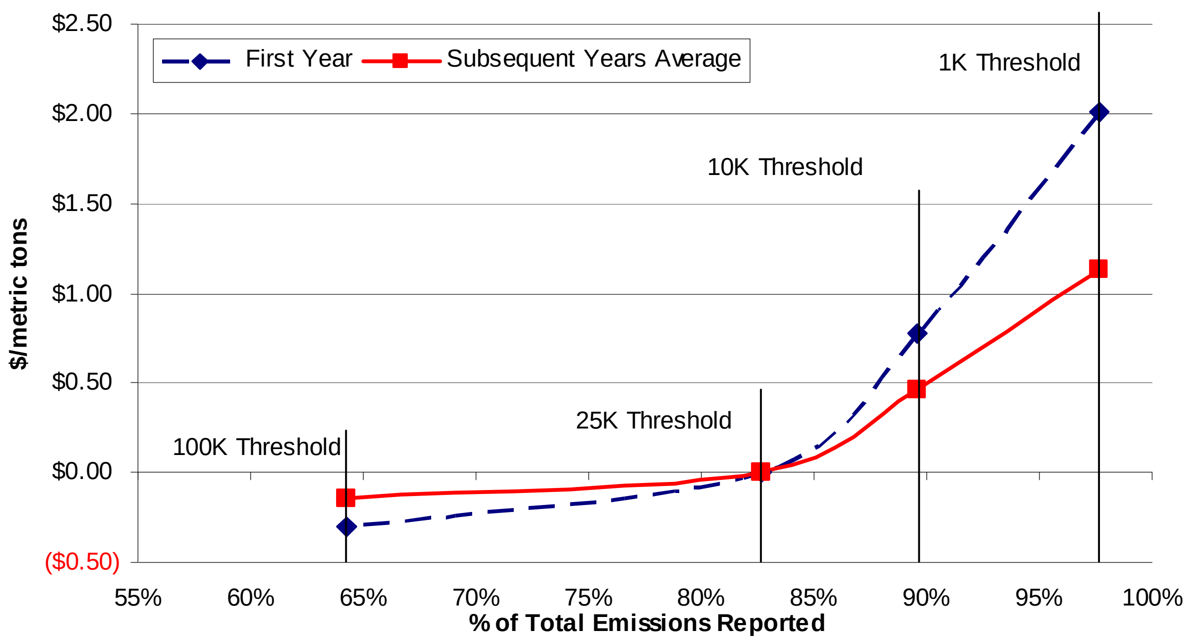
The selection decision weighed the marginal cost of capturing additional emissions with the percentage of emissions needed to accurately estimate the U.S. GHG emissions nationally and by segment. This is shown in Figure 5-1, which illustrates the total average cost per metric ton and the marginal cost per metric ton for Subpart W as a function of the percentage of total emissions reported.

Figure 5-1 Average and Marginal Cost per Metric Ton of Emissions Reported by Threshold

a. Average Cost



b. Marginal Cost Relative to Final Rule



5.1.2 Analysis of Alternative Monitoring Method Options

Each monitoring technique for which reporting costs were estimated for Subpart W in Section 4 was assumed in the burden analysis to provide the same estimate of total emissions by reporting facility – as estimated in the analysis by the U.S. Inventory as amended with additional methods discussed earlier in this document. However, the methods proposed for monitoring emissions will differ in their precision in estimating actual emissions. Therefore, the gain from increasing the cost of monitoring is to have more precise estimates of facility emissions. The methods considered for determining emissions ranged from applying average industry parameters (referred to as "population emission factors," or "default parameters") to material inputs or throughputs, to the use of direct measurement techniques. In this section, we evaluate the change in cost and change in accuracy for two alternative monitoring options for Subpart W. Generally speaking, under one of the alternatives, population factors would be used in lieu of direct measurements and facility-level estimates, and in the other option, direct measurements are required for all sources. We use the term direct measurement and "population factors" as shorthand to describe alternative options. For Subpart W, population emission factors and component count is the basis for "default factors". Estimated costs for each monitoring method are shown in Table 5-7.

For Subpart W, the direct measurement option greatly expands to use direct measurement of all vented and fugitive sources. This is the methodology used in the initial rule proposal. The costs associated with this case in the original rule proposal (which did not include the added segments of onshore production and natural gas distribution) resulted in Subpart W incurring 19% of the total costs in the MRR to monitor and measure only 3% of the emissions.

These costs were re-estimated for the entire petroleum and natural gas segment in the revised rule proposal. These costs involve the use of direct measurement techniques, including metering of all vents, calibrated bagging or use of high volume samplers to measure fugitive and inaccessible leaks, and so on. These costs involve additional equipment as well as significantly higher labor costs. If the same direct measurement techniques were proposed in this rule, the costs would be particularly high for the new onshore production and natural gas distribution segments.

The overall costs for the direct measurement option are about $100 million (annually) higher than the selected option.

Table 5-7 Analysis of Alternative Monitoring Methods

Segment	Direct Measurement (DM)		Selected Option (Hybrid Approach)		Population Factors	
	First Year (million 2006$)	Subsequent Years (million 2006$)	First Year (million 2006$)	Subsequent Years (million 2006$)	First Year (million 2006$)	Subsequent Years (million 2006$)
Subpart W—Petroleum and Natural Gas Systems	$294.6	$126.9	$59.9	$25.3	$27.6	$17.4

For the “population factor” option, Subpart W sources were assumed to have emissions quantified entirely by the application of emissions factors developed by the Gas Research Institute and EPA (GRI/EPA 1996) as the basis for estimates of CH_4 and non-combustion-related CO_2 emissions. These factors are used with a population count of equipment and components to arrive at a “population factor” cost estimate. The reduction in cost from the selected Hybrid Approach for this option is significant, with first year costs declining by $32.3 million, and subsequent year costs declining by $7.9 million.

5.1.2.1 Monitoring Method Uncertainty

The use of direct measurement methods would provide the most certain quantification of Subpart W emissions, assuming that measurements were taken using consistent monitoring protocols across reporters. If emission sources are measured as estimated in the burden analysis, there should be a high certainty level in the emissions quantified. However, based on the analysis above, the costs to gather and quantify these emissions would be very high.

The use of population based factors would result in a significantly lower burden, although the certainty level of the emissions determination would be very poor. Population-based factors determine the *potential* for emissions assuming a percentage of known components which may leak based on previous (and dated) studies.

The recommended option of using leak detection and a hybrid of spot direct measurement, engineering estimates, leaker emission factors, and population based factors (for inaccessible sources) provides an emissions estimate with significantly more certainty than population based factors at a more reasonable burden.

5.1.3 Sensitivity of Subsequent Year Cost Estimates

National cost estimates for the Subpart W proposed rule option were developed based on the current population of entities in the petroleum and natural gas segment. The forward analysis (“subsequent years”) assumes that the number of entities would remain relatively constant. Thus, the analysis assumes a stable population where all entities subject to Subpart W bear a single first-year cost and then repeated subsequent-year costs.

However, in reality, over time some existing facilities close or go out of business and new facilities come into existence. This is sometimes referred to as entry and exit in an industry. This may affect the cost of the rule because as entities “turn over” the new entrants presumably will bear first-year costs that are slightly higher than subsequent year costs.

The largest contribution to non-recurring first-year costs for Subpart W compliance is for flow measurement port installation in compressor seal vent lines. When a company goes out of business and sells its assets to either a new or existing business, these ports will already be installed; so much of the first-year compliance costs will not apply to a company acquiring an already-reporting facility. The remainder of first-year costs that do not repeat is due to labor associated with reviewing the regulation and planning accordingly for compliance. These costs will not be necessary when an existing company, which already reports, acquires a reporting facility from a failing business. Only in the case of a new business entity acquiring an existing or new reporting station will these reviewing and planning first-year labor costs be necessary.

The reviewing and planning costs are minimal in comparison to the significant other first year costs of reporting for Subpart W, therefore the impact of business transitions on rule reporting costs for Subpart W are assumed minimal.

5.1.4 Summary of Alternative Options for Onshore Facility Definition

The proposal specifies that onshore petroleum and natural gas producers will report for each hydrocarbon basin. A basin is as identified by the American Association of Petroleum Geologists three digit Geologic Province Code. The reporters will be a owners or operators in a basin. However, EPA also considered an alternate option to define a facility at a field level. One such definition is available from the Energy Information Administration Petroleum and Gas Field Code Master. The field level option would require aggregation of emissions by owners or operators at a field level to apply the threshold. Table 5-8 and Table 5-9 below show a detailed emissions coverage and burden to reporter from the potential adoption of a field level facility definition.

Table 5-8 Emissions Coverage and Entities Reporting for Field Level Facility Definition (Onshore Production)

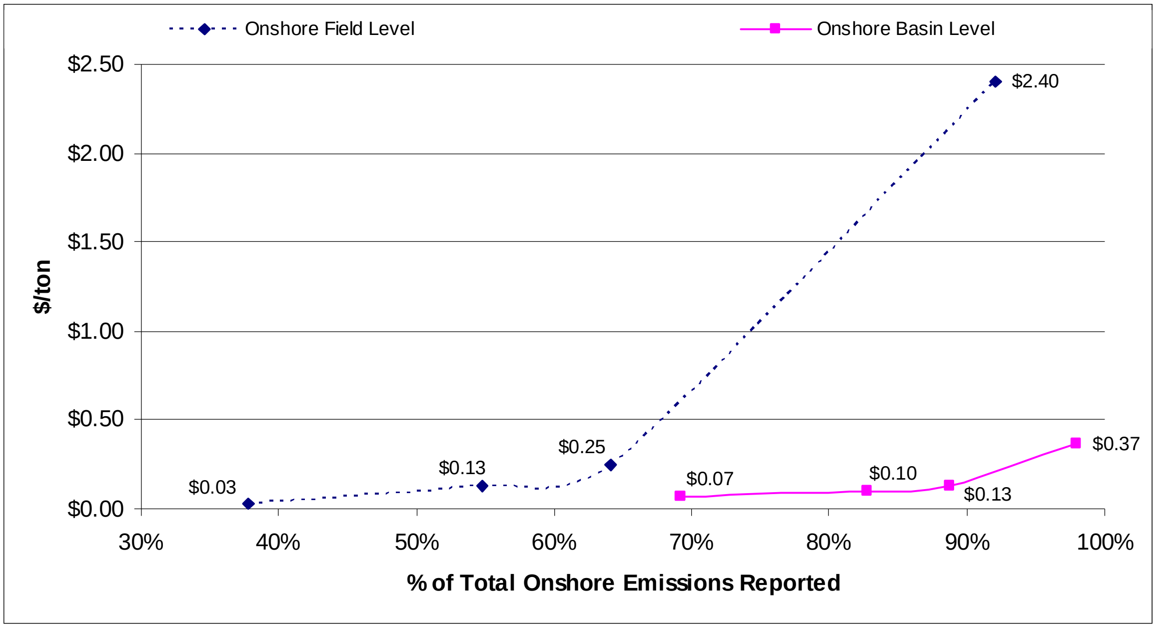
Threshold Level	Emissions Covered		Facilities Covered	
	Metric tons CO_2e/year	Percent	Number	Percent
1,000	242,621,431	92%	39,652	48%
10,000	169,160,462	64%	2,846	3%
25,000	144,547,282	55%	1,253	2%
100,000	99,776,033	38%	305	0%

Table 5-9 Fugitive and Vented and Combustion Emissions Cost for Field Level Facility Definition (Onshore Production)

Threshold Level[2]	Fugitive and Vented Emission Costs				Combustion Emission Costs			
	Year 1 Costs		Year 1 Costs		Year 1 Costs		Year 2 Costs	
	Annualized Capital Cost	O&M Cost	Annualized Capital Cost	O&M Cost	Annualized Capital Cost	O&M Cost	Annualized Capital Cost	O&M Cost
1,000	$325	$6,748	$270	$2,473	$500	$1,700	$500	$1,700
10,000	$1,035	$9,904	$270	$3,856	$500	$1,700	$500	$1,700
25,000	$1,270	$11,001	$270	$4,357	$500	$1,700	$500	$1,700
100,000	$1,270	$11,388	$270	$4,672	$500	$1,700	$500	$1,700

Figure 5-2 shows a comparison of average costs (years 1, 2, and 3) and emissions coverage at different thresholds for the field and basin level options. It can be observed that the field level option would result in a significantly lower coverage in emissions reported at 55 percent in comparison to the basin level coverage of 81 percent for a 25,000 metric tons CO_2e threshold. In addition, the field level definition cost to report is higher than the basin level definition at all thresholds, except at 100,000 metric tons CO_2e threshold, where field level is lower. But at the 100,000 CO_2e threshold the coverage from field level definition is very low at 38 percent. Finally, the number of entities reporting at a 25,000 metric tons CO_2e threshold for basin level definition is lower at 1,181 in comparison to the 1,253 entities reporting for a field level definition.

Figure 5-2 Summary of Basin vs. Field Decision



5.2 Assessing Economic Impacts on Small Entities

The first step in this assessment was to determine whether the rule will have a significant impact on a substantial number of small entities (SISNOSE) under Subpart W. To make this determination, EPA used a screening analysis that allows us to indicate whether EPA can certify the rule as not having a SISNOSE. The elements of this analysis included

- identifying affected entities under Subpart W,
- selecting and describing the measures and economic impact thresholds used in the analysis, and
- determining SISNOSE certification category.

5.2.1 Identify Affected Segments and Entities

The affected entities covered by the rule were identified during the development of the cost analysis for the reporting rule. The Statistics of U.S. Businesses (SUSB) data provides national information on the distribution of economic variables by the size of entity. These data were developed in cooperation with, and partially funded by, the Office of Advocacy of the Small Business Administration (SBA) (SBA, 2008a). The data include the number of establishments (Table 5-10), employment (Table 5-11), and receipts (Table 5-12) and present information on *all* entities in an industry covered by Subpart W of the rule; however, many of these entities would not be expected to report under the selected option because they would fall below the 25,000 hybrid threshold. SUSB also provides this data by enterprise employment size. The census definitions in this data set are as follows:

- ***Establishment***: An establishment is a single physical location where business is conducted or where services or industrial operations are performed.

- ***Employment***: Paid employment consists of full- and part-time employees, including salaried officers and executives of corporations, who were on the payroll in the pay period including March 12, 2002. Included are employees on sick leave, holidays, and vacations; not included are proprietors and partners of unincorporated businesses.

- ***Receipts***: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.

- ***Enterprise***: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008c) apply to an establishment's "ultimate parent company," we assume in this analysis that the "enterprise" definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses and the terms are used interchangeably. We also report the SBA size standard(s) for each industry group in order to facilitate comparisons and different thresholds.

Table 5-10 Number of Establishments by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Estab-lish-ments	Owned by Enterprises with:						
					1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	< 500 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; LNG storage; LNG import and export.	211	Crude Petroleum and Natural Gas Extraction	500	7,629	5836	456	292	60	6,584	64	31
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage	486210	Pipeline Transportation of Natural Gas	[b]	1,936	81	27	61	36	169	2	20
Natural gas distribution	221210	Natural Gas Distribution	500	2,897	483	86	131	68	700	33	73

[a]The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.
Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.
[b]The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

Table 5-11 Number of Employees by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Employees	Owned by Enterprises with: 1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	< 500 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; LNG storage; LNG import and export	211	Crude Petroleum and Natural Gas Extraction	500	88,280	19,336	12,113	11,656	2,421	43,105	3,551	1,061
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage	486210	Pipeline Transportation of Natural Gas	[b]	37,450	347	157	1,053	[c]	1,934	[c]	[c]
Natural gas distribution	221210	Natural Gas Distribution	500	86,890	1,956	1,899	4,398	1,960	8,420	2,631	5,014

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.
Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c] The U.S. Census Bureau has missing data for this employee range.

Table 5-12 Receipts by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Receipts ($Million)	Owned by Enterprises with: 1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	< 500 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; LNG storage; LNG import and export	211	Crude Petroleum and Natural Gas Extraction	500	$160,879	$7,573	$6,789	$9,608	$4,608	$23,972	$3,991	$2,805
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage	486210	Pipeline Transportation of Natural Gas	[b]	$35,897	$1,035	$106[c]	$394[c]	[c]	$2,566	[c]	[c]
Natural gas distribution	221210	Natural Gas Distribution	500	$67,275	$2,524	$4,642	$2,878	$865	$13,127	$2,116	$3,757

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.
Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.
[b]The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

cThe U.S. Census Bureau has missing data for this employee range. The receipts for the one to 20 range therefore underestimate true value.

5.2.2 Develop Small Entity Economic Impact Measures

Because Subpart W covers businesses, the analysis generated a set of sales tests (represented as cost-to-receipt ratios)[16] for NAICS codes associated with the affected Subpart W segments. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed us only to compute and compare ratios for a ***model establishment*** for eight *enterprise size* ranges (i.e., all categories, enterprises with 1 to 20 employees, 20 to 99 employees, 100 to 499 employees, 500 to 749 employees, less than 500 employees, 750 to 999 employees, and 1,000 to 1,499 employees). This approach allows us to account for differences in establishment receipts between large and small enterprises and differences in small business definitions across affected Subpart W industries. It is also a conservative approach, because an establishment's parent company (the "enterprise") may have other economic resources that could be used to cover the costs of the reporting program. It must be noted that the 1,000 to 1,499 employee category does not belong to the small business category. However, the category has been included to provide a comparison with small business cost-to-receipt ratios.

These sales tests examine the average establishment's total annualized mandatory reporting costs to the average establishment receipts for enterprises within several employment categories[17] (first year costs: Table 5-13; subsequent year costs: Table 5-14). The average entity costs used to compute the sales test are the same across all of these enterprise size categories. As a result, the sales-test will overstate the cost-to-receipt ratio for establishments owned by small businesses, because the reporting costs are likely lower than average entity estimates provided by the engineering cost analysis.

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[16]The following metrics for other small entity economic impact measures (if applicable) would potentially include

- Small governments (if applicable): "Revenue" test; annualized compliance cost as a percentage of annual government revenues.
- Small non-profits (if applicable): "Expenditure" test; annualized compliance cost as a percentage of annual operating expenses.

[17]For the one to 20 employee category, we exclude SUSB data for enterprises with zero employees. These enterprises did not operate the entire year.

Table 5-13 Establishment Sales Tests by Industry and Enterprise[a] Size: First Year Costs

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($1,000/ entity)	All Enter-prises	Owned by Enterprises with:						
						1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	< 500 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; LNG storage; LNG import and export	211	Crude Petroleum and Natural Gas Extraction	500	$24	0.11%	1.83%	0.16%	0.07%	0.03%	0.65%	0.04%	0.03%
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage	486210	Pipeline Transportation of Natural Gas	[b]	$18	0.10%	0.14%	0.47%[c]	0.28%[c]	[c]	0.12%	[c]	[c]
Natural gas distribution	221210	Natural Gas Distribution	500	$11	0.05%	0.22%	0.02%	0.05%	0.09%	0.06%	0.02%	0.02%

[a]The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b]The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c]The U.S. Census Bureau has missing data for this employee range; some estimates were possible using partial data. The receipts for these categories underestimate true value.

Table 5-14 Establishment Sales Tests by Industry and Enterprise[a] Size: Subsequent Year Costs

						Owned by Enterprises with:						
Industry	**NAICS**	**NAICS Description**	**SBA Size Standard (effective March 11, 2008)**	**Average Cost Per Entity ($/entity)**	**All Enter-prises**	**1 to 20 Employees**	**20 to 99 Employees**	**100 to 499 Employees**	**500 to 749 Employees**	**< 500 Employees**	**750 to 999 Employees**	**1,000 to 1,499 Employees**
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; LNG storage; LNG import and export	211	Crude Petroleum and Natural Gas Extraction	500	$9	0.04%	0.69%	0.06%	0.03%	0.01%	0.25%	0.01%	0.01%
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage	486210	Pipeline Transportation of Natural Gas	[b]	$9	0.05%	0.07%	0.23%[c]	0.14%[c]	[c]	0.06%	[c]	[c]
Natural gas distribution	221210	Natural Gas Distribution	500	$7	0.03%	0.13%	0.01%	0.03%	0.05%	0.04%	0.01%	0.01%

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c] The U.S. Census Bureau has missing data for this employee range; some estimates were possible using partial data. The receipts for these categories underestimate the true value, which results in conservative estimates of cost-to-sales ratios.

5.2.3 Results of Screening Analysis

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

For the purposes of assessing the impacts of Subpart W of the rule on small entities, we defined a small entity as (1) a small business, as defined by SBA's regulations at 13 CFR Part 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

EPA believes the selected thresholds maximize the rule coverage with 83% of all U.S. petroleum and natural gas systems emissions reported by approximately 3,037 reporters, while keeping reporting burden to a minimum and excluding small emitters. Furthermore, many Subpart W industry stakeholders with whom EPA met expressed support for a 25,000 metric ton of CO_2e threshold because it sufficiently captures the majority of GHG emissions in the United States while excluding smaller facilities and sources. After considering the economic impact of the proposed rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. As shown in Table 5-13 and Table 5-14, the average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1% for industries presumed likely to have small businesses covered by the reporting program.

The only exception to this is the ratio for 1-20 employee range for crude petroleum and natural gas extraction, which is greater than 1 percent but less than 2 percent. The petroleum and natural gas industry has a large number of enterprises, the majority of them in the 1-20 employee range. However, a large fraction of production comes from large corporations and not the small with less than 20 employee enterprises. The smaller enterprises in most cases deal with small operations (such as a singly family owning a few production wells) that are unlikely to cross even the 25,000 metric tons CO_2e threshold considered for the rule. An exception to such a scenario is a small (less than 20 employee) enterprise owning large operations but conducting nearly all of its operations through contractors. This is not an uncommon practice in the onshore petroleum and natural gas production segment. Such enterprises, however, are a very small group among the over 19,000 enterprises in the less than 20 employee category and EPA proposes to cover them in the proposed rule.

5.3 Synopsis of Benefits

Under the mandatory GHG reporting rule EPA proposes to collect and verify emissions data from Subpart W facilities. This section reviews the benefits of a mandatory reporting program for Subpart W facilities based on previous experience with emissions inventory programs in the United States and abroad.

Recent policy discussions have highlighted potential benefits to society of the mandatory GHG reporting program (Pew, 2008). Benefits to the public include building public confidence through clear and transparent emission measures and reports and the ability of the public to make petroleum and natural gas facilities accountable for their vented and fugitive emissions. A GHG reporting system will also have the benefit of providing policy makers and analysts with a data set that is comprehensive for the petroleum and natural gas industry if reporting is conducted under Subpart W and other applicable subparts. Benefits to the industry include the identification of cost-effective GHG reduction opportunities and disclosure that provides firms with incentives to reduce emissions voluntarily, and provides emissions data to service industries, such as insurance and financial markets. Availability of emissions information to the public, consumers, investors, corporations and government regulators provides a sound basis for future policy analysis. This benefits society as a whole. Accurate and transparent information is necessary for the implementation of efficient approaches that meet environmental goals with the lowest cost to the economy.

SECTION 6
STATUTORY AND EXECUTIVE ORDER REVIEWS

This section describes EPA's compliance with several applicable executive orders and statutes during the development of Subpart W of the mandatory GHG reporting rule.

6.1 Executive Order 12866: Regulatory Planning and Review

Under EO 12866, (58 Federal Register (FR) 51735, October 4, 1993) the Agency must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the EO. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;

2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

3. Materially alter the budgetary impact of entitlement, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the EO.

Pursuant to the terms of Executive Order 12866, it has been determined that this proposed rule is a "significant regulatory action" because it raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the EO. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866.

However, this action is not an "economically significant regulatory action" under EO 12866 because it is unlikely to have an annual economic effect of $100 million or more. Nonetheless, EPA has prepared this analysis of the potential costs and benefits associated with this action.

In the economic analysis, EPA has identified the regulatory options considered, their costs, and the emissions that would likely be reported under each option, and explained the selection of the option chosen for the rule. The cost analysis, presented in Section 4, estimates that under the regulatory option, the total annualized cost of Subpart W will be approximately $60 million during the first year of the program and $25 million in subsequent years (not including $1.2 million of programmatic costs to the Agency). In addition, EPA has conducted a qualitative assessment of the benefits of the rule, which are reported in Section 5. Overall, EPA has concluded that the costs of the proposed mandatory GHG reporting rule for Subpart W are outweighed by the potential benefits of more comprehensive information about GHG emissions.

6.2 Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

EPA plans to collect complete and accurate economy-wide data on facility-level GHG emissions. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Through data collected under this rule, EPA will gain a better understanding of the relative emissions of petroleum and gas systems, and the distribution of emissions from individual facilities within those systems. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and the actions that facilities are already taking to reduce emissions. Additionally, EPA will be able to track the trend of emissions from petroleum and gas systems over time, particularly in response to policies and potential regulations. The data collected by this rule will improve EPA's ability to formulate climate change policy options and to assess which petroleum and gas systems would be affected, and how these systems would be affected by the options.

This information collection is mandatory and will be carried out under CAA Sections 114 and 208. Information identified and marked as Confidential Business Information (CBI) will not be disclosed except in accordance with procedures set forth in 40 CFR Part 2. However, emissions information collected under CAA Sections 114 and 208 generally cannot be claimed as CBI and will be made public[18].

The projected cost and hour respondent burden in the ICR is $37.8 million and 478,774 hours per year. The estimated average burden per response is 98.2 hours; the frequency of response is annual for all respondents that must comply with the rule's reporting requirements. The cost burden to respondents resulting from the collection of information includes the total capital and start-up cost annualized over the equipment's expected useful life (averaging $5.3 million per year) a total operation and maintenance component (averaging $1.6 million per year), and a labor cost component (averaging $30.9 million per year). Burden is defined at 5 CFR Part 1320.3(b). These cost numbers differ from those shown elsewhere in the Economic Impact Analysis because ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the Economic Impact Analysis for the first year of the rule and for subsequent years of the rule. Also, the total cost estimate of the rule in the Economic Impact Analysis includes the cost to the Agency to administer the program. The ICR differentiates between respondent burden and cost to the Agency.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR Part 9 in the Federal Register to display the OMB control number for the approved information collection requirements contained in the final rule.

6.3 Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

[18] Although CBI determinations are usually made on a case-by-case basis, EPA has issued guidance in an earlier Federal Register notice on what constitutes emissions data that cannot be considered CBI (956 FR 7042 – 7043, February 21, 1991). As discussed in Section II.R of the Final MRR preamble, EPA is initiating a separate notice and comment process to make CBI determinations for the data collected under this rulemaking. EPA intends to issue this notice in early 2010, and will include in the notice the data proposed for collection in this rulemaking

For purposes of assessing the impacts of this proposed rule on small entities, small entity is defined as: (1) a small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

First, EPA examined the effect of Subpart W on small businesses using data collected by SUSB and SBA on the number of establishments, enterprises, employees, and receipts of businesses to allocate first-year and subsequent year costs to small businesses and assess the impact. Data limitations allowed EPA to only to compute and compare ratios for a *model establishment* for six *enterprise size* ranges (i.e., all categories, enterprises with 1 to 20 employees, 20 to 99 employees, 100 to 499 employees, 500 to 749 employees, less than 500 employees, 750 to 999 employees, and 1,000 to 1,499 employees). This approach is conservative because an establishment's parent company (the "enterprise") may have other economic resources that could be used to cover the costs of the reporting program. Section 5.2 provides further description of these methods.

These sales tests examine the average establishment's total annualized mandatory reporting costs to the average establishment receipts for enterprises within several employment categories. The average entity costs used to compute the sales test are the same across all of these enterprise size categories. As a result, the sales-test will overstate the cost-to-receipt ratio for establishments owned by small businesses, because the reporting costs are likely lower than average entity estimates provided by the engineering cost analysis.

EPA believes the selected thresholds maximize the rule coverage with over 83 percent of all U.S. petroleum and natural gas systems emissions reported by approximately 3,037 reporters, while keeping reporting burden to a minimum and excluding small emitters. Furthermore, many Subpart W industry stakeholders with whom EPA met expressed support for a 25,000 metric ton of CO_2e threshold because it sufficiently captures the majority of GHG emissions in the United States while excluding smaller facilities and sources. After considering the economic impact of the rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. The average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1 percent for industries presumed likely to have small businesses covered by the reporting program.

Second, EPA determined that the supplemental proposed rulemaking would not have a significant impact on small governmental jurisdictions. EPA determined that one segment of the petroleum and natural gas industry might include small governments affected by the supplemental proposed rulemaking. A comparison of the compliance costs to the revenue of potentially affected small governmental jurisdictions revealed that the costs of the rule are less than 1% of revenues.

Third, EPA concluded that the supplemental proposed rulemaking would not affect a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Specifically, the data listing entities in each segment of the petroleum and natural gas industry did not include any non-profit entities.

Although this proposed rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this proposed rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA is proposing different monitoring methods for different emissions sources, requiring direct measurement only for selected sources. Also, EPA is proposing annual instead of more frequent reporting.

Through comprehensive outreach activities prior to proposal of the original MRR, EPA held approximately 100 meetings and/or conference calls with representatives of the primary audience groups, including numerous trade associations and industries in the petroleum and gas industry that include small business members. EPA's outreach activities prior to proposal of the initial rule are documented in the memorandum, "Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule," located in Docket No. EPA-HQ-OAR-2008-0508-055. After the original proposal, EPA posted a guide for small businesses on the EPA GHG reporting rule Web site, along with a general fact sheet for the rule, information sheets for every source category, and an FAQ document. EPA also operated a hotline to answer questions about the proposed rule. We continued to meet with stakeholders and entered documentation of all meetings into the docket.

During rule implementation, EPA would maintain an "open door" policy for stakeholders to ask questions about the proposed rule or provide suggestions to EPA about the types of compliance assistance that would be useful to small businesses. EPA intends to develop a range of compliance assistance tools and materials and conduct extensive outreach for the proposed rule.

We have therefore concluded that today's proposed rule will relieve regulatory burden for all affected small entities. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

6.4 Unfunded Mandates Reform Act

The UMRA seeks to protect State, local, and Tribal governments from the imposition of unfunded Federal mandates. In addition, the Act seeks to strengthen the partnership between the Federal government and State, local, and Tribal governments and ensure that the Federal government covers the costs incurred during compliance with Federal mandates.

Title II of the UMRA of 1995, Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private segment. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with Federal mandates that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private segment, of $100 million or more in any one year.

Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the Subpart W rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private segment in any one year. Expenditures associated with compliance, defined as the incremental costs beyond the existing regulations will not surpass $100 million in the aggregate in any year. Thus, today's rule is not subject to the requirements of sections 202 and 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This regulation applies to facilities that directly emit greenhouses gases. It does not apply to governmental entities unless the government entity owns a facility in the petroleum and gas industry that directly emits greenhouse gases above threshold levels. In addition, this proposed rule does not impose any implementation responsibilities on State, local, or Tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those governments. Thus, the impact on governments affected by the proposed rule is expected to be minimal.

6.5 Executive Order 13132: Federalism

Executive Order 13132, entitled “Federalism” (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure “meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications.” “Policies that have federalism implications” is defined in the executive order to include regulations that have “substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.”

This rule does not have Federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

This regulation applies to public- or private-segment facilities that directly emit GHGs from petroleum and natural gas systems. Relatively few government facilities would be affected. This regulation also does not limit the power of states or localities to collect GHG data and/or regulate GHG emissions. Thus, Executive Order 13132 does not apply to this rule.

6.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (59 FR 22951, November 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

This supplemental proposed rule may have tribal implications, as specified in Executive Order 13175. This regulation would apply to facilities that directly emit GHGs from petroleum and natural gas systems. Although few facilities that would be subject to the rule are likely to be owned by tribal governments, EPA has sought opportunities to provide information to tribal governments and representatives during rule development.

In consultation with EPA's American Indian Environment Office, EPA's outreach plan included tribes. During the initial rule proposal phase, EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two tribal board members of TCR. In addition, EPA prepared a short article on the GHG reporting rule that appeared on the front page of a tribal newsletter—*Tribal Air News*—that was distributed to EPA/OAQPS's network of tribal organizations. EPA gave a presentation on various climate efforts, including the mandatory reporting rule, at the National Tribal Conference on Environmental Management in June, 2008. In addition, EPA had copies of a short information sheet distributed at a meeting of the National Tribal Caucus. EPA participated in a conference call with tribal air coordinators in April 2009 and prepared a guidance sheet for Tribal governments on the proposed rule. It was posted on the MRR website and published in the Tribal Air Newsletter. For a complete list of tribal contacts, see the "Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule," in the Docket for this rulemaking (EPA-HQ-OAR-2008-0508-055).

6.7 Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

EPA interprets Executive Order 13045 (62 F.R. 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5-501 of the executive order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

6.8 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This rule is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that this rule is not likely to have any adverse energy effects.

This proposal relates to monitoring, reporting, and recordkeeping at facilities that directly emit GHGs from petroleum and natural gas systems; it does not impact energy supply, distribution or use. Therefore, we conclude that this rule is not likely to have any adverse effects on energy supply, distribution, or use.

6.9 National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104-113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, with explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA proposes to use consensus standards bodies. These voluntary consensus standards will help facilities monitor, report, and keep records of GHG emissions. No new test methods were developed for this rule. Instead, from existing rules for source categories and voluntary GHG programs, EPA identified existing means of monitoring, reporting, and keeping records of GHG emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, such as methods to analyze fuel, methods to measure gas or liquid flow, and methods to gauge and measure petroleum and petroleum products. The test methods are incorporated by reference into the rule and are available as specified in Section 98.7 of subpart A. Additional methods that would be incorporated under this supplemental proposed rulemaking are GlyCalc and E&P tanks.

By incorporating voluntary consensus standards into this rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring GHGs.

6.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment; it is a rule addressing information collection and reporting procedures.

SECTION 7
CONCLUSIONS AND IMPLICATIONS

In this Economic Impact Analysis, EPA has examined the regulatory background, the development of the mandatory GHG reporting rule for Subpart W, and estimated the costs and benefits of implementing this subpart. This section presents our overall conclusions.

7.1 Discussion of Results

EPA has developed this proposed rule in response to language contained in the FY 2008 Consolidated Appropriations amendment (December 26, 2007), which authorized funding for EPA to publish the rule on an accelerated schedule. The major market failure that the rule is designed to address is one of inadequate or asymmetric information: while existing state and federal programs collect similar data, the resulting data are neither comprehensive nor consistent for Subpart W sources. As such, they are an inadequate basis for the formation or evaluation of future climate policy that will impact the petroleum and natural gas segments.

7.1.1 Development of the Proposed Rule

EPA examined several regulatory alternative scenarios that were developed by varying options across two program dimensions: Threshold and Monitoring Methodology. The proposed regulatory alternative for Subpart W calls for:

- a threshold of 25,000 tCO_2e threshold for all facilities, and
- a hybrid methodology, including use of direct spot measurement, facility-specific calculation methods, and use of emission factors (leaker and population factors)

Other scenarios evaluated included the following:

1. A 1,000 tCO_2e threshold; selected options for methodology, frequency, and verifier.
2. A 10,000 tCO_2e threshold; selected options for methodology, frequency, and verifier.
3. A 100,000 tCO_2e threshold; selected options for methodology, frequency, and verifier.
4. The measurement variable is changed to direct spot measurement; selected option for threshold.
5. The measurement variable is changed to default emissions factors; selected option for threshold.

7.1.2 Affected Source Categories

EPA considered direct emitters of fugitive and vented GHGs under Subpart . From these emission sources, EPA identified eight segments under the Subpart W source category for which costs and impacts were examined.

7.2 Assessment of Costs and Benefits of the Mandatory GHG Reporting Rule

7.2.1 Estimated Costs and Impacts of the Mandatory GHG Reporting Program

Under the rule, EPA estimates that 3,037 entities would be covered by Subpart W of the rule, directly emitting 351 Million mtCO_2e per year. The total annualized costs incurred under the rule by these entities would be $59.9 million for the first year and $25.3 million for subsequent years.

Overall, economic impacts on industry segments are measured by comparing per-entity costs with average per entity receipts. These cost-to-sales ratios are less than 1% for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by a business with 20 or more employees) and small government entities. This analysis enables EPA to determine that the proposed rule will not have a significant economic impact on a substantial number of small entities. Overall, Subpart W of the rule will impose national costs exceeding $59.9 million in the first year and $25.3 million in subsequent years; the costs will be widely dispersed throughout the economy and relatively low on a per-entity basis. The estimated national costs represent less than 0.001% of 2007 gross domestic product. Thus, EPA does not estimate that there will be significant impacts on the economy in general or on individual segments or small entities within Subpart W.

7.2.2 Summary of Qualitative Benefits Assessment

EPA did not quantify the estimated benefits of the rule. Instead, a qualitative assessment was performed, based on information from the literature and previous benefits assessments of existing emissions inventory programs.

Recent policy discussions have highlighted potential benefits to society of the GHG reporting program (Pew, 2008). Benefits to the public include building public confidence through clear and transparent emission measures and reports and the ability of the public to make facilities accountable for their emissions. Benefits to petroleum and natural gas industry include the identification of GHG reduction opportunities and disclosure, which provides firms with incentives to reduce emissions voluntarily, and provides emissions data to service industries, such as insurance and financial markets. A GHG reporting system will also have the benefit of providing policy makers and analysts with a comparable data set that is comprehensive and reduces the potential for policy bias. In addition, a mandatory reporting system is a key element to an overall GHG policy; no effort can succeed without it.

Studies published by OECD (2005) and EPA (2003) have documented benefits to various stakeholders, including the public, industry, investors, and government, of existing pollutant release and transfer registers (PRTRs) These benefits are likely similar to the benefits that would be experienced as a result of the mandatory GHG reporting rule, and thus they provide a basis for a qualitative characterization of those benefits. The studies examined in Section 5 of this economic impact analysis describe the following types of benefits:

- Public
  - increased levels of trust towards government and industry where there are right-to-know laws concerning emissions;
  - information to enable citizens to negotiate directly with polluters; and
  - information to enable environmentally aware consumers to alter their consumption habits based on GHG emissions of producers.
- Industry
  - Public relations: having independent, verifiable data to present to the public would demonstrate appropriate environmental stewardship.
  - Standardization: uniform industry standards would reduce the cost of reporting relative to non-uniform, jurisdiction-specific, and allow facilities to benchmark their performance against other similar facilities.
  - Potential cost savings: mandatory monitoring may uncover previously unmeasured wasteful processes, yielding cost-saving conservation opportunities that would offset some of the costs of monitoring.
  - Potential customer data for service industries: information about GHG-emitting firms will be useful for firms that market emissions-reduction technologies, and to insurance companies for assessing risk.
- Investors
  - Information about emissions will enable investors to implement socially responsible investing using GHG emission information if they so choose.
- Government
  - Policy development: The greatest benefit to government of mandatory GHG reporting is the comprehensive, consistent data it would provide, enabling government to develop accurate, informed future GHG policy.

– Comparability: A mandatory system would reduce the difficulties associated with comparing across different reporting standards across states or programs.
– Compliance and policy evaluation: Publicly available nationwide data on GHG emissions will enable government to develop and robustly evaluate environmental policies, and to ensure compliance with the policies once implemented.

7.3 What Did We Learn through This Analysis?

EPA's examination of the costs and benefits of the provisions in Subpart W of the mandatory GHG reporting rule revealed that the proposed rule will impose an estimated $34 million (based on average costs over the first four years) in monitoring, recordkeeping, and reporting costs on emitters of GHGs that are widely distributed throughout the U.S. economy. Impacts of the costs on individual segments and entities are expected to be generally small, comprising less than 1% of entity receipts and approximately 0.001% of 2007 GDP. Thus, despite the overall national costs, macroeconomic impacts are not anticipated, and EPA does not believe that the proposed rule will impose significant economic impacts on a substantial number of small entities.

A review of the literature enabled us to characterize the expected types of benefits, which will be experienced by stakeholders, including the public, industry, investors, and government. Based on this qualitative assessment and evidence from other existing programs, EPA expects the benefits of the proposed rule to be substantial.

SECTION 8
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