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June 9, 2009

U.S. Environmental Protection Agency
EPA Docket Center (DPA/DC)
Mail code 6102T
Attention: Docket ID No. EPA-HQ-OAR-2008-0508
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Comments by the American Petroleum Institute on the Environmental Protection Agency's Proposed Mandatory Reporting Rule for Greenhouse Gas Emissions

Dear Docket Clerk:

The American Petroleum Institute (API) appreciates the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed mandatory reporting rule (MRR) for greenhouse gas (GHG) emissions[1]. API represents about 400 companies involved in all aspects of the oil and natural gas industry throughout the USA and globally. API has an extensive record of ongoing activities related to GHG emissions estimation and reporting for nearly a decade, and its guidelines are used worldwide for developing corporate GHG emission inventories for all segments of the oil and natural gas industry.

API and its members fully appreciate the need for a consistent approach to GHG emissions calculations and reporting, and it supports the need for a single, harmonized, national GHG emissions reporting program. Such a program should ensure data uniformity and fungibility and strive to avoid a burdensome patchwork of conflicting definitions and reporting rules.

The proposed MRR has broad implications for all sectors of the economy. API's members will be impacted by the rule – as proposed – both as operators of hundreds of facilities of varying sizes, as well as the suppliers of the fuels that are essential to the functioning of the U.S. economy.

API's full comments (as presented in the attached document) include responses to EPA requested feedback as well as issues raised by API and its members. The goal of API's comments is to advise EPA about it concerns with the proposed rule so that the final rule, when

[1] Federal Register (FR), volume 74, number 68, pages 16448-16731, April 10, 2009.

promulgated, will inform national greenhouse gas management policy without overburdening the reporters.

API and it's members reviewed the proposed rule carefully and are raising issues ranging from overarching concerns to detailed technical comments, all in an effort to make the MRR easier to implement in practice. The comments are organized into five main sections:

I. Key program principles;
II. Overarching issues in the proposed MRR;
III. EPA solicited feedback and comments on program design and general provisions;
IV. Detailed legal analysis; and
V. Detailed technical comments keyed to the MRR subparts.

Among the key principles API views as essential, in the final MRR, we would like to note that:

- The MRR should be designed to inform national GHG policy decisions without predetermining the structure of the eventual regulatory framework,
- The MRR should have economy-wide coverage, while avoiding redundant collection of information already being reported to other federal agencies, and
- The MRR should make a clear distinction between emissions data and sensitive business information that ought to be maintained confidential.

Upon analyzing the proposed MRR, API and its members have identified the following set of overarching issues:

- Legislative authority;
- Linkage to CAA provisions: PSD, NSR, Title V;
- Treatment of Confidential Business Information;
- List of Greenhouse Gases proposed for reporting;
- Duration and frequency of data collection under this rule;
- Requirements for new measurements and instrumentation under this rule;
- Disproportionate regulatory burden on the oil & natural gas industry;
- Compatibility with regional and state reporting programs;
- Delegation of authority to states for implementation;
- Exclusion of indirect emissions;
- Clarification of reporting obligations;
- Proper citation and use of industry standards;
- Unnecessary requirements for reporting petroleum products supply;
- Redundancy and burden of fuels supply reporting;
- Exclusion of onshore oil and natural gas production from reporting; and
- Carbon Capture and Storage vs. Enhanced Oil Recovery.

These issues are numbered when presented in the attached document, though the numbers are used for ease of reference without indicating a priority order. In addition to discussing the

overarching issues the attached document also includes issues related to program design and its general provisions, applicable legal analysis of selected issues, and technical comments on each of the relevant subparts of the proposed MRR.
API would like to inform EPA that it is conducting a survey to quantify the impact of the proposed MRR on its members. Due to the short time period provided for submittal of comments, API did not complete yet all information collection and analysis. API will share with EPA the survey results, and related technical information, upon it completion. API expects to present this additional information to EPA in the July 2009 timeframe.

API stands ready to continue discussing with EPA how to improve the proposed rule, and will be available to participate in developing various technical implementation tools for prospective reporters.

Finally, API and its members will welcome the opportunity to augment the written comments and provide EPA with additional information or clarifications, as needed.

Sincerely,

Karin Ritter

ATTACHMENT: Complete API Comments in five sections (136 pages total) & Appendix A (12 pages total)

Cc:
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Docket ID No. EPA-HQ-OAR-2008-0508

U.S. Environmental Protection Agency (EPA)

Proposed Greenhouse Gas Mandatory Reporting Rule

(74 FR 68, Friday, April 10, 2009, Proposed Rule)

Comments By:

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Table of Contents

API – BACKGROUND AND CREDENTIALS

API is the premier trade association in the oil and natural gas industry with over 400 member companies comprising the full gamut of this sectors operations and business enterprises. Its member companies include oil and natural gas exploration, production, and processing; petroleum refining; storage, distribution, and transportation, of crude oil, petroleum products and natural gas (including natural gas liquids and LNG); as well as marketing products to the end-consumer.

API and its members have been at the cusp of developing methodologies for greenhouse gas (GHG) emissions reporting for the industry and beyond for over a decade now. Oil and natural gas industry experts have participated as drafting and advisory committee members for many, if not all, of GHG emissions methodologies and reporting protocols. API experts have contributed to the development of global standards and to emission inventory guidance for national GHG emissions inventories. The industry is also engaged and participates in consultations on mandatory GHG reporting regulations such as in the European Union emissions trading system (EU-ETS); in the province of Alberta, Canada; and in California and the Western Climate Initiative. API is also a member of the Technical Working Group (TWG) for the Western Regional Air Partnership (WRAP) that is collaboratively developing protocols for reporting from the exploration and production sector of the oil and natural gas industry.

API's multi-year initiative has resulted in the development and publication of several key guidance documents and tools to promote the consistent and accurate quantification and reporting of GHG emissions from oil and natural gas industry operations, and a framework for assessing GHG emission reductions from specific projects. These publicly available documents include:

- A compilation of applicable GHG estimation methodologies (API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry);
- Guidelines for reporting GHG emissions (API/IPIECA Petroleum Industry Greenhouse Gas Reporting Guideline); and
- A series of guidelines to assist the oil and natural gas industry in identifying, assessing, and developing candidate projects that would lead to credible GHG emission reductions (GHG Project Guidelines).

Based on API's and its member companies' broad experience – as outlined above - and upon broad consultation on the proposed rule, API is pleased to provide below detailed comments, which are organized as follows:

I. Key program principles;

II. Overarching Issues in the proposed mandatory reporting rule (MRR);

III. EPA solicited comments on program design and general provisions;

IV. Detailed legal analysis; and

V. Detailed Specific comments keyed to the MRR subparts.

API and its members fully appreciate the need for a consistent approach to GHG emissions calculations and reporting and it supports the need for a single, harmonized, national GHG emissions reporting program. Such a program should ensure data uniformity and fungibility and strive to avoid a burdensome patchwork of conflicting definitions and reporting rules. Since atmospheric releases of

GHGs are dealt with by national negotiations on a global basis, there is a need for a nationwide reporting program that is based on a common set of authorities, rules, and procedures.

I. KEY PROGRAM PRINCIPLES

The U.S. Environmental Protection Agency (EPA) proposed MRR has broad implications for all sectors of the economy. API's members will be impacted by the rule – as proposed – both as operators of hundreds of facilities of varying sizes, which will be subject to reporting, as well as the suppliers of fuels subject to reporting and which are essential to the functioning of the U.S. economy.

API has previously discussed with EPA general issues concerning the objectives and construct of an MRR at this point in time. API would like to offer some key principles for EPA's consideration as it moves towards finalizing this MRR:

1. The rule should be designed to inform national GHG policy decisions without predetermining the structure of the eventual regulatory framework. Monitoring and reporting provisions should be appropriate to the goal of informing policy and not reflect a pre-determined view of likely policy outcome.

2. The rule should have economy-wide coverage and attempt to avoid duplicative information collection by other federal agencies, or creation of redundant systems to account for fuel quantities supplied. EPA should do the utmost to harmonize its data collection mandates with existing data systems instead of creating duplicative reporting mandates.

3. The rule as proposed has broad business data confidentiality implications. Careful consideration ought to be given to delineate data that are required for developing national policy, as compared to data that should be made publicly available. Some of the detailed information requested, on a facility-by-facility basis, is at the heart of competitive enterprises.

4. In considering its range of options EPA should ensure – and state so explicitly - that this reporting rule does not automatically trigger other Clean Air Act (CAA) obligations for the GHG reporting entities.

5. Data reported should be limited to reporting of GHG emissions under the direct operational control of the reporter, and the threshold for reporting should be based on actual releases of GHGs to the atmosphere.

6. The rule should not impose any new measurement requirements, but rather allow reporters to utilize best existing data. Significant capital and operational expenditures should not be required to obtain information prior to a final legislative and/or regulatory framework.

7. Reporting frequency should be selected to meet information needs and anticipated use of the data. Annual reporting might be applicable for an interim data collection effort to inform policy. However, in the absence of a defined policy framework reporting (and the rule) should "sunset" when sufficient information is collected to inform policy development – perhaps after three years.

II. OVERARCHING ISSUES

API provides below comments on overarching issues for EPA consideration when promulgating the final rule. The issues are numbered for ease of reference, which should not be construed as representing an order of priority. These overarching issues are further expanded upon either through detailed legal analysis (Section IV), or detailed technical comments on the individual subparts (Section V to end), or both.

1. Legislative authority

"…the Agency to use its existing authority under the Clean Air Act to develop and publish a rule requiring mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy" and *"The Administrator shall have discretion to use existing reporting requirements for electric generating units under Section 821 of the Clean Air Act"* (HR2764 Conference Report – 1254-1255).

API comments

The authority granted to EPA refers primarily to sections 114, and 208 of the Clean Air Act (CAA). EPA's use of Section 114 has been properly limited historically to issuing Information Collection Requests (ICRs) to collect data to develop such programs as the maximum achievable control technology (MACT) or the clean air mercury rule (CAMR). ICRs have historically been limited to collecting data from specific sources over a discrete period of time, usually relying on existing data, or a subset of the potential universe of sources, or both. Section 114 has not previously been used to justify an essentially economy-wide, on-going reporting rule requiring all affected entities to submit data annually with new monitoring and measurement processes.

Section 821 of Public Law 101-549 is limited to power generating units subject to the provisions of the Acid Rain Program. If EPA had the authority it now claims to have under Section 114, it would have been unnecessary for Congress to explicitly authorize EPA under section 821 to establish ongoing CO_2 monitoring and reporting requirements for power generating units. For reasons discussed above, interpreting Section 114 so broadly as to obviate the requirements of other parts of the CAA or other federal statutes would violate a basic principle of statutory construction and would be an abuse of discretion, not in accordance with the law, and in excess of statutory authority.

EPA is over-reaching its authority under Clean Air Act Sections 114 and 208. As explained in greater detail in Section IV, these provisions do not authorize the proposed indefinite and burdensome monitoring, recordkeeping, and reporting from most sectors of the economy. As EPA has acknowledged, the rule was proposed in response to the 2008 Consolidated Appropriations Act. This Act provides limited funding, does not grant EPA any enforcement authority, and expressly limits the proposed rule to the reporting of greenhouse gas "emissions." EPA's proposal goes well beyond these constraints.

2. **Linkage to CAA provisions: PSD, NSR, Title V**
   a) *"All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part."* (throughout the preamble and the rule)

   API comments

   The rule should include a clarifying statement that terms used/defined in this subpart take precedence over the meaning in the CAA. Applicable CAA definitions cited in other subparts should only be used if such terms are not defined specifically in this subpart. As a corollary, the same terms used in different manners and/or with different meanings in the MRR should be explicitly defined where necessary.

   b) *"Any information collected under the mandatory GHG reporting program would assist EPA and others in developing future climate policy"*

   "Footnote: At this time, a regulation requiring the reporting of GHG emissions and emissions-related data under CAA sections 114 and 208 does not trigger the need for EPA to develop or revise regulations under any other section of the CAA, including the PSD program" (*74 FR 68, page 16456).*

   API comments

   API urges EPA to state, in the final rulemaking, that none of the requirements of the rule make CO_2 or any other GHG "subject to regulation" under the CAA. As explained in Section IV, EPA's past practice and statements, the agency's definitive interpretation of its own regulations, and the plain meaning of the relevant statutory language support this well-established position. API also recommends that the final rule make clear that the monitoring rule's application to a particular facility will not trigger any other CAA obligations and would not establish any "applicable requirements" that must be contained in Title V operating permits.

3. **Treatment of Confidential Business Information**

   EPA is addressing confidential business information as follows:

   "EPA would protect any information claimed as CBI in accordance with regulations in 40 CFR part 2, subpart B. However, note that in general, emission data collected under CAA sections 114 and 208 cannot be considered CBI. 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 FR7042 – 7043, February 21, 1991)". (74 FR 68, page 16463)

   API comments

   The proposed rule has numerous requests for data that if made publicly available would result in divulging confidential business information (CBI); especially true in the subparts dealing with suppliers, importers and exporters of fuels and other products (i.e., 40 CFR 98, Subparts MM, NN, and PP). The preamble quote above addresses only the confidentiality, or lack thereof, of emissions information, but not the issue of the confidentiality associated with the marketing and distribution of fuels and products.

There is a clear distinction between facilities emissions, which may not be subject to CBI, and EPA's requested information on fuel supplies on a facility-by-facility basis. The information on fuel quantities and the carbon content are not actual emissions, merely a surrogate for potential emissions, if all the fuels would have been combusted. Supporting information, such as fuel supplies (quantity and origin), unit throughput, production volumes, etc. are all competitive information. Facilities need to prevent competitors from having this information, in order to prevent one obtaining a competitive advantage over others (by being able to reverse engineer their competition's operations and business strategies).

Therefore, special provisions are needed to maintain the confidentiality of this data. Companies are providing fuel supply and quality data to federal agencies like the EPA, Energy Information Administration (EIA), Customs & Border Patrol (CBP) and similar agencies. However, it is the nature of business, and companies' prerogative, to keep competitive information from each other. Therefore, EPA ought to acknowledge the need for strict confidentiality, and to set up processes that would prevent the release of data unless it is aggregated, to prevent identification of individual company information. EPA should note in this regard the confidentiality provisions used by the EIA for collection of industry fuel supply information, as shown in Exhibit 1 below.

Exhibit 1 - Confidentiality

(Extracted from Petroleum Supply Monthly, Appendix B: Explanatory Notes, March 2007)

The information reported on these forms will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905. The Energy Information Administration (EIA) will protect your information in accordance with its confidentiality and security policies and procedures.

The Federal Energy Administration Act requires the EIA to provide company-specific data to other Federal agencies when requested for official use. The information reported on these forms may also be made available, upon request, to another component of the Department of Energy (DOE), to any Committee of Congress, the General Accounting Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order. The information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.

Company specific data are also provided to other DOE offices for the purpose of examining specific petroleum operations in the context of emergency response planning and actual emergencies.

Disclosure limitation procedures are not applied to the statistical data published from these surveys information. Thus, there may be some statistics that are based on data from fewer than three respondents, or that are dominated by data from one or two large respondents. In these cases, it may be possible for a knowledgeable person to estimate the information reported by a specific respondent.

Similar to the discussion of fuel marketing and distribution information, disclosure of the detailed facility process and operational information required would divulge confidential business information related to ownership interests, processes employed by individual facilities, and business practices at individual facilities.

Both for fuels and facility reporting, EPA should carefully assess what is actually needed for policy decisions and make a clear distinction between what is mandated for reporting vs. what would be disclosed publicly. All the ancillary data that is required for reporting, and which could help EPA better understand and verify the emissions information, should be kept confidential and not included in any of the public reports.

As noted above, the proposed rule would require the reporting of confidential business information ("CBI") that goes well beyond "emissions data" and whose disclosure would reveal sensitive competitive information. API urges EPA, in the final rulemaking, to make a "class determination" pursuant to 40 C.F.R. § 2.207 that the fuels production and distribution data requested of suppliers meets the regulatory requirements for CBI protection. Similarly, much of the operational data requested of petroleum refineries should be handled as confidential. As explained in Section IV, the requested information satisfies all of the substantive criteria for receiving confidential treatment. See 40 C.F.R. §§ 2.208, 2.301(e).

4. List of Greenhouse Gases proposed for reporting

In the preamble to the proposed rule EPA provides a rationale for its selection of the Kyoto Protocol listed GHGs as the foundation for reporting under this rule. Additionally, EPA elected not to include other compounds, such as water vapors, ozone depleting substances (ODS), tropospheric O_3, or 'black carbon'.

API comments

In response to EPA's request for comments on the selection of GHGs that are - or are not - included in the proposed rule, API supports the selected approach. This approach would make the U.S. program more consistent with efforts by other countries around the globe. It would also prevent duplication or redundancy with the range of EPA, State and Local Agency programs that are already being implemented to control ODS, tropospheric O_3 and fine particles (including soot or 'black carbon').

API also supports the approach where the list of target compounds for reporting is pared down, or adjusted, for the different source categories based on typical gases that might be emitted from their operations. As such API supports that the primary focus for reporting should be CO_2, CH_4 and N_2O, when appropriate for the source categories. GHG emissions should be characterized and reported only when specifically listed for a specific source category or a range of sources.

5. Duration and frequency of data collection under this rule

In the preamble to the proposed rule, EPA discusses its consideration of a multi-year program that would sunset absent subsequent regulatory action by EPA to extend it. EPA is soliciting input both on the duration of the program as well as the frequency of reporting, as stated in the preamble:

"EPA is interested in receiving data and analyses regarding frequency of reporting and the schedule for reporting. In particular, we solicit information regarding whether the frequency of data collection and reporting selected by EPA is appropriate for each source category or whether alternative frequencies should be considered (e.g., quarterly or every few years)".

"EPA is interested in receiving data and analyses regarding options for the duration of the GHG emissions information collection program in this proposed rule. By duration, EPA means for how many years the program should require the submission of information. EPA solicits input on whether the duration selected by EPA is appropriate for each source category or whether an alternative approach should be adopted". (74 FR 68, page 16463)

API comments

During earlier communications with EPA, API maintained that the legislative mandate for this data collection is to guide policy decisions and future legislation. Any interim reporting requirements crafted now would have to be amended to support any future specific programs to reduce emissions.

API is recommending that EPA consider adopting a reporting program that is of a finite duration, perhaps lasting initially for three years. Such duration will provide EPA, and Congress, with the needed data to support regulatory and legislative options, and is consistent with previous limited duration data collection under the authority of Section 114 of the CAA. It would also be compatible with the OMB clearance process and approval of data collection forms and tools.

When considering reporting frequency one has to be cognizant of the need for frequency as compared to reporting burden. Reporting frequency and report content should be designed to meet current needs, and should be amended as new legislative and/or regulatory mandates are promulgated. In the case of an interim reporting program, of a finite duration, annual reporting would provide needed emission data information.

6. Requirements for new measurements and instrumentation under this rule

"EPA crafted the requirements in this rule with the potential monitoring, recordkeeping and reporting requirements for any future regulations addressing GHG emissions in mind. EPA solicits comment on all of these possible approaches, including whether EPA should commit to revisit the continued necessity of the reporting program at a future date". (74 FR 68, page16478)

API comments

Reporting requirements should be designed to meet the information collection needs to inform national GHG policy decisions without predetermining the structure of the eventual regulatory framework. These requirements ought to be consistent with, and adopt elements from, existing reporting protocols and guidelines, for example, the API/IPIECA Reporting Guidelines and API's "Compendium of GHG Emissions Methodologies for the Oil and Gas Industry" (API Compendium), which are widely used by the oil and natural gas industry worldwide. These guidelines and other existing protocols may all be acceptable within the context of 'best available data' for MRR.

The MRR should not impose any new measurement requirements or mandate installation of new instrumentation, and should not require either capital expenditures, or excessive operating expenses, to report GHG data to EPA. Examples for such overly burdensome requirements include: leak detection and quantification programs; use of Hi-flow samplers and component 'bagging'; installation of new channels on existing CEMS; fuels carbon content analysis; storage tank flow measurements and head space analysis; flare velocity metering; and fuel combustion metering. EPA should review the need for annual leak detection surveys and leak quantification, especially for remote locations and for areas where logistically it is overly burdensome to perform the specified tests at the proposed frequency. API is proposing a range of alternative approaches to measurements and monitoring under Section III.13 below, with additional applicable comments under the respective subparts.

As a practical matter EPA should consider industry's inability to install, test and calibrate all flow meters, and other required instrumentation, and develop the appropriate data archiving systems, within the exceedingly short duration between the expected rule promulgation and effective date. Moreover, where new instrumentation has to be installed or existing instrumentation upgraded, such modifications could not be implemented while process units are up and running.

API does not believe that it is EPA's intent to mandate units shutdown for improved data collection. A better approach is to rely on 'best available data' until the instrumentation upgrades can be installed during the next unit shutdowns for scheduled maintenance.

By utilizing a 'best available data' approach, without mandating new monitoring and measurement obligations immediately, EPA's MRR will be easier to implement in practice and be more appropriate with the stated intent and consistent with previous data collection activities undertaken under the authority of Section 114 of the CAA.

7. Disproportionate regulatory burden on the oil & natural gas industry

EPA states its rationale for selecting the source categories for reporting as,

"The source categories identified in this list were selected after considering the language of the Appropriations Act and the accompanying explanatory statement, and EPA's experience in developing the U.S. GHG Inventory. The Appropriations Act referred to reporting ''in all sectors of the economy'' and the explanatory statement directed EPA to include ''emissions from upstream production and downstream sources to the extent the Administrator deems it appropriate.'' (74 FR 68, page 16465)

In the cost analysis presented in Table VIII-1 in the preamble, and in the accompanying Regulatory Impact Assessment (RIA), rule implementation will cost some $168MM in the first year, down to $134MM from the second year on, with 95% of the cost to be borne by the affected industry. EPA does not present anticipated costs from evaluating alternative regulatory scenarios to justify their selection of the framework outlined in the MRR.

API comments

The proposed rule impacts the oil and natural gas industry through the requirements of reporting both as facility operators and fuel suppliers. This creates a disproportionate regulatory burden and compliance costs on the oil and natural industry when compared to other industry sectors that have to report only their GHG emissions, or other sectors that have been almost totally excluded from reporting, as, for example, the agricultural industry.

EPA's cost impact data in Table VIII-1 presents data for each of the subparts separately, but fails to consider the overall burden per facility as facilities are subject to more than one subpart. In addition, these costs fail to account for additional staff likely to be required to ensure compliance with the extensive requirements. API believes the costs presented are not accurate but, given the short comment period, have not been able to develop cost surveys and more robust analyses.

Even if the overall costs are not underestimated, the costs for the oil and gas industry are high relative to other sectors. A few examples are provided below to demonstrate the point, assuming that the costs presented by EPA in Table VIII-1 in the preamble are correct:

a) General Stationary Fuel Combustion accounts for 6% of downstream emissions, but its first year total annualized costs would amount to 17% of the total share.

b) Oil and natural gas systems account for 3% downstream emissions but its first year total annualized costs are estimated to be 19% of the total share.

c) Petroleum refineries are estimated to account for 5% of the downstream emissions with an estimate that their total annualized cost is 2% of overall costs. This figure does not account for the cost of reporting for the stationary combustion units, or for electricity generation from cogeneration systems, which many refineries have installed to increase their energy efficiency and reduce the intensity of GHG emissions. In addition, refineries would also have to bear the cost of reporting under the landfill and wastewater provisions.

The information made available to the public through the rule docket is inadequate for conducting an independent review of EPA's calculations and many of the assumptions that form the basis for the cost estimates given in the RIA. For example, EPA omitted from the RIA and its appendix the source equipment and component counts that define each of its model facilities. Additionally, the RIA gives just a single cost estimate assumed to represent the average cost to a facility, irrespective of the different types of facilities that fall under the respective Subpart.

For subpart W, for example, EPA provided an alternative set of cost estimates in the docket that is not referenced anywhere in the RIA or in the proposed rule notice. This alternate cost estimates assume third-party contracting for the required fugitive emissions measurements, and are assumed to be 45% lower than the cost estimates given in the RIA. Documentation of the alternative cost estimates is given in a PDF file (EPA-HQ-OAR-2008-0508-138) filled with 87 pages of spreadsheet screenshots with no text explaining the origins of the numbers or how the different pages link together in the original spreadsheet.

API is in the process of conducting a survey of its members to collect detailed information on anticipated costs of compliance and regulatory impact. The short time duration for providing these comments precluded API from summarizing the survey results in this comments package, and they will be provided to EPA as soon as available. API will advise EPA on the results of its regulatory impact cost survey in the July 2009 time frame.

8. Compatibility with regional and state reporting programs

EPA reviewed existing federal, regional and state GHG emissions reporting programs, covering both voluntary and mandatory reporting initiatives. EPA concluded that none of the existing programs meets all the requirements set forth for a nationwide program regarding breadth of coverage and uniformity of reporting. EPA uses the conclusions of their review as the basic rationale for the program that they are proposing, and are seeking comments on their findings.

"EPA seeks comment on whether the conclusions drawn during its review of existing programs are accurate and invites data to demonstrate if, and if so how, the goals and objectives of this proposed mandatory reporting system could be met through existing programs. In particular, comments should address how existing programs meet the breadth of sources reporting, thresholds for reporting, consistency and stringency of methods for reporting, level of reporting, frequency of reporting and verification of reports included in this proposal." (74 FR 68, page 16461)

<u>API comments</u>

API supports the need for a single, harmonized, national GHG reporting program. Such a program should ensure data uniformity and fungibility and strive to avoid a burdensome patchwork of conflicting definitions and reporting rules. Since atmospheric releases of GHGs are dealt with by national negotiations on a global basis, there is a need for a nationwide reporting program that is based on a common set of authorities, rules, and procedures.

As previously communicated by API to EPA, API recommends for this initial data collection phase - that GHG emission estimates developed under state-only programs should be acceptable and sufficient for meeting federal reporting obligations.

Additional elements including measurements, reporting and data certification requirements should be addressed if and when an emissions reduction program is defined.

9. Delegation of authority to states for implementation

EPA recognizes that state and local agencies routinely interact with many of the facilities that are targets for reporting under this rule. Also, Section 114 (b) of the CAA allows EPA to delegate authority to states to implement and enforce Federal rules. EPA is not proposing to formally delegate implementation of the rule to state and local agencies, but is asking stakeholders to provide feedback.

"Overall, we request comments on the role of States in implementing this rule and on how States and EPA could interact in administering the reporting program." 74 FR 68, page 16594

API comments

For GHG emissions reporting, which is not a local air issue but national, API would support EPA retaining full control and authority over this program until new legislative or regulatory mandates are developed. States could have a role to play in providing technical assistance on how to implement the EPA mandated data reporting.

10. Exclusion of indirect emissions

EPA addresses in the preamble the issue of inclusion, or exclusion, of reporting indirect emissions (Scope 2 and 3). EPA requests comments on reporting the quantity of electricity purchased:

"We are also taking comment on, but not proposing at this time, requiring facilities and supply operations affected by the proposed rule to also report the quantity of electricity purchased". (74 FR 68, page 16473)

API comments

API supports EPA's decision to not include reporting of indirect emissions, or electricity consumption, into this reporting rule. Indirect emissions were originally included in voluntary entity reports in order to demonstrate the range of an entity's GHG impacts, from both direct and indirect GHG emissions. However, for the MRR, information about indirect emissions, or even electricity consumption data, is not needed for developing future regulatory strategies to address GHG emissions.

Accounting for either indirect GHG emissions, or electricity consumption, will add a layer of complexity and burden that outweighs the benefit that might be accrued. Site-specific electricity data is not available in many remote locations. Also, most companies accounting systems track the dollar value of electricity consumed but not the respective kWh. Therefore reporting electricity consumption would require new systems to accumulate kWh data or calculation of kWh from invoices. Depending at what timeframe this is done; calculation from invoices could be very inaccurate due to large variations in electricity costs between regions, providers and time of service pricing. If EPA desires data on how electricity is employed in the economy, the needed information is likely available from the EIA power generation reports.

11. Clarification of reporting obligations

In § 98.2 EPA states**,**

"(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements, of this part apply to the owners and operators of any facility that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section…" (74 FR 68, page 16612)

and it goes on to list the source categories that are subject to reporting and the respective subparts and applicability thresholds.

API Comments

The section cited above is titled in the proposed MRR, "Do I need to report?" API and its members have reviewed the information provided by EPA within the context of typical industry business arrangements and how these various permutations would be implemented in practice. Aside from the legal construct, different business structure of ownership and operations also has implications on data availability and the ability to monitor and certify applicable GHG emissions.

Two examples out of the many permutations where 'owners' and 'operators' might lead to different reporting obligations,

a) Facilities that are co-located on a common site, but under different fractional ownership and different operational control, and

b) Captive operations, within a host site, which are neither owned nor operated by the overall facility owner/operator.

API contends that the demarcation of a *"reporter"* is the one who has operational control. EPA says that "*operational control*" (see footnote on page 16592) is defined as *"having the full authority to introduce and implement operational, environmental, health and safety policies.*" This definition is consistent with the API/IPIECA *Petroleum Industry Greenhouse Gas Reporting Guidelines.*

This interpretation also follows the definition in California's AB32 program, which states "*'Operational Control' for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article."*

API recommends that EPA include California's definition of operational control in the final MRR to minimize confusion and ascertain proper determination of reporting obligations.

Additionally, API recommends that EPA exempt from the rule's requirements passive owners and other entities that have no operational connections to the facility with reporting obligations. For example, EPA should adopt an exemption similar to the TRI program for certain owners of leased property. In that program, "[t]he owner of a covered facility is not subject to reporting . . . if such owner's only interest in the facility is ownership of the real estate upon which the facility is operated." *See* 40 C.F.R. § 372.38(e). At a minimum, EPA should include such an exemption in this rule. API also requests an opportunity to further discuss with EPA additional classes of owners or operators that are appropriate for exemption from the rule's requirements.

12. Proper citation and use of industry standards

EPA seeks comments on the appropriateness of citing specific industry standards for sampling of petroleum products,

"…we request comment on the appropriateness of the proposed sampling and analysis standards and methods for developing CO_2 emission factors for petroleum products and NGLs, especially the methods for determining carbon share. Specifically, we seek comment on specific ASTM or other industry standards that would be more appropriate for sampling petroleum products and NGLs to determine carbon share". (74 FR 68, page 16572)

API Comments

API welcomes EPA's reference to industry consensus standards, such as ANSI, API, ASTM, ISO and other standard setting organizations that have rigor in the development of measurement standards. However, it may not be effective or efficient for EPA to reference specific measurement standards and specific editions of those standards, as is the case in the proposed Subpart MM. Such a comprehensive list would require considerable resources for maintenance and updating, since measurement standards are reviewed at least every five years to ensure that standards are consistent with technological changes and advancements.

This rule, if enacted, may itself drive the development of additional standards to use more cost effective or newly developed technologies or extend existing methods to cover materials that previously were not covered. The references to individual industry standards that appear in some parts of the proposed rule are incomplete and some are outdated. Industry uses standards from several different standards developing organizations resulting in equivalent measurements, based on the scope of the standard, company preference, and type of device used. API publishes one of the more comprehensive sets of custody transfer measurement standards, but it is neither complete nor the only widely recognized source for such industry practices [see Appendix A]. For example, to effectively list some of the individual standards that need to be referenced one would have to include the entire API Manual of Petroleum Measurement Standards (MPMS) (which comprises over 140 titles) and other related standards. Notably, API publishes approximately eight new or revised measurement standards each year.

API recommends that EPA direct the reporter to use suitable methods from a "*consensus standards organization*". This provides the Agency with an assurance of technical accuracy and transparency in the methods used, while at the same time not restricting the reporters to an infrequently updated list. The approach taken by EPA in the proposed Subpart NN (Sec. 98.404) is more effective than that of proposed lists of standards as given in Subpart MM. It relies on *"using any of the oil and gas flow meter test methods that are in common use in the industry and consistent with the Gas Processors Association Technical Manual and the American Gas Association Gas Measurement Committee reports".* This construction still has the problem that it limits the reporter to a very restricted set of standards from amongst several well respected organizations, but it does not trap both EPA and the industry into a role of specifying details that are not critical to the objectives of the proposed MRR. Paragraph 98.164(d) improves on the construction by specifying the type of standards organization that meets the Agency's needs by giving examples without excluding potentially acceptable organizations, quoting *"using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others)".*

API is providing more specific comments with potential language changes with the detailed comments on each of the respective subparts in Section V below to demonstrate how this could be accomplished while ensuring good QA.

13. Unnecessary requirements for reporting petroleum products supply

EPA is proposing and new and far reaching reporting framework for petroleum products supply, as follows:

"Owners or operators of petroleum refineries, or ''refiners,'' and importers that introduce petroleum products into the U.S. economy would be required to report on the CO2 emissions associated with the complete combustion or oxidation of their petroleum products". (74 FR 68, page 16569)

<u>API Comments</u>

API believes petroleum fuel refiners, importers, and exporters should not have to conduct additional reporting on petroleum feed stock and product volumes and GHG emissions to EPA. We already provide extensive data on the requested volumes of finished petroleum products and feedstocks to other federal and state agencies on a weekly, monthly, and annual basis. These existing reporting schemes provide essential protection of these competitively sensitive data as Confidential Business Information (CBI). EPA would be able to have access to these data provided they agree to keep that data business confidential. Agreeing to keep the data confidential would not preclude the agency from developing emission profiles from each refinery's products.

The proposed rule goes beyond the authorizing legislation's direction to require reporting of "…greenhouse gas emissions…" by requesting detailed data on volumes of interim and final petroleum products and even crude oil feed stocks, which are not relevant to estimating GHG emissions. It would establish duplicative reporting requirements and raises questions regarding EPA's legal authority to manage sensitive data as CBI (see legal analysis of CBI in Section IV). EPA should coordinate with agencies like the Department of Energy (DOE) and Customs and Border Protection (CBP) to make use of existing reporting data and processes to support development of future climate policy.

As designed, the current proposed reporting system will result in significant overstatement of emissions for some facilities, as clearly some products are not combusted. The concern is twofold:

- **a)** There are the products that will not be combusted (asphalt, lubricants, etc.). These should be flagged or excluded somehow. There should be some way for the refinery to indicate that the end use of the product does not result in its combustion; and
- **b)** There are feedstocks that will either have to be further processed or blended (for example, naphtha). The refinery that processes the feedstock and produces the extra volume of product should be the one that reports. If a facility has the ability to determine that the stream will not be combusted they should be able to exclude it from their GHG emissions calculations.

Additionally, EPA's requirements for reporting of "natural gas liquids" (NGLs) contained in Subparts MM and NN will result in significant "double counting" of NGLs and reporting of NGLs which are used for chemical feedstock and do not result in GHG emissions from their combustion. In fact, most of the NGL produced in the U.S. or imported is used as feedstock rather than fuel – as noted in EPA's Technical Support Document. Odorized propane and/or butane are almost exclusively used for NGL-based fuels, and should be the focus of the rule rather than the broad production of all NGLs.

API suggests that reporting of NGLs be restricted to odorized propane and/or butane (or propane/butane mix) and that such reporting only be required from facilities which fractionate NGLs into these particular components, which are the only sources of fuel quality propane/butane. This will avoid the double counting of mixed NGLs that are subsequently fractionated at different facilities and reported a second (or perhaps third) time. It will also avoid the reporting of NGLs that are not suitable for or destined for fuel use and subsequent emissions.

API also suggests that a reporting threshold equal to the volume of odorized propane and/or butane which would yield 25,000 metric tons of emissions if fully combusted be included in the rule to exclude small facilities.

14. Redundancy and burden of fuels supply reporting

EPA discusses the utmost importance of accurate volumetric measurements and carbon content information for fuel suppliers:

"Rather than directly measuring emissions from the combustion or consumption of their products, suppliers of petroleum products would need to estimate the potential emissions of their non-crude feedstocks and products based on volume and characteristic information. Therefore product volume metering and sampling would be of utmost importance to accurately calculate potential CO_2 emissions." (74 FR 68, page 16572)

API Comments

Section 98.394 requires refineries and importers and exporters of petroleum products to measure the quantity of petroleum products, natural gas liquids, biomass, and all feedstocks using a flow meter of specified types or tank gauge that are calibrated according to the standards and methods referenced in the rule. The listed methods and standards specified are not complete and nor are they inclusive enough to describe the actual methods used to measure these materials for custody transfer. Many other methods of measurement are used, using many different industry standards. Imposition of the proposed methodologies would create the need to change thousands of custody transfer systems without any benefit or justification.

For fuel suppliers who will be subject to reporting under the proposed MRR, the most accurate quantity information in their possession is that on which they base their financial records. These records are the basis for reporting inventories as well as commercial purchase & sale payments of which any potential "carbon costs" would be only a fraction. These financial records also have the benefit of being subject to audit under existing internal controls, Sarbanes-Oxley regulations, as well as Internal Revenue Service (IRS), Customs & Border Protection (CBP) and other regulatory compliance systems. Any attempt to under-report such quantities under the proposed MRR would be impractical, as it would involve a third party, likely to object and report the infraction. It would likely result in one of the two parties incurring a financial loss greater than the impact of any potential reporting rule.

EPA's proposed MRR would require setting up a separate - though somewhat similar – data set. This data set, containing information about quantities of fuels and products transferred, would require a substantial amount of resources on the part of EPA to develop the computer systems needed to record and track the data as well as entail substantial expenditures for reporters. Use of two separate data systems, one for financial records and another for environmental data, that contain the same information about quantities of fuels transferred, could easily be cross-posted into the wrong system. This could lead to corrupting both sets of data. We suggest that EPA take advantage of existing custody transfer and accounting systems and avoid devising a redundant "second set of books" for fuels movement.

The existing financial records already contain volumes (or weights) for all materials that are shipped into or out of a facility identified by material-specific codes. Even low value or waste products are measured before shipment, if only to determine freight or disposal charges or DOT compliance.

For imported fuels, CBP is the federal agency tasked with enforcing regulatory requirements around calculation of imported quantities of bulk petroleum feedstocks and products. 19 CFR§151 Examination, Sampling and Testing of Merchandise details the requirements and Subpart C of 19 CFR§151 deals specifically with petroleum and petroleum products. The CBP in its guideline for approval and validation of FTZ petroleum measurement systems (including sampling) state that petroleum measurement systems must be approved (i.e. 19 CFR 151.42 (a) (1) (i) and 151.42 (a) (3)) and are typically accepted if those petroleum measurement systems "meet or exceed the installation, operational, and performance criteria found in the "appropriate" (sic current edition) API Manual of Petroleum Measurement Standards (MPMS).

For marine movements, third party gaugers bonded and approved by CBP's Laboratory and Scientific Services group are to be employed to objectively determine quantities of bulk petroleum materials being imported at refineries and chemical plants. Subpart C of 19 CFR§151 deals specifically with petroleum and petroleum products. Third party gaugers are approved by CBP prior to carrying out any marine measurement work and they are tasked with assuring the accuracy of the data. CBP periodically audits third party gaugers to ensure their practices and equipment are in accordance with industry requirements.

Importers and exporters of record often do not own or operate the equipment used to transport or store materials including flow meters and tank gauges. Instead, the importer and exporter are contracted to handle the transfer of materials. The quantities of materials are measured by CBP, which has a rigorous program to ensure measurement accuracy. The CBP program also applies to some refinery feedstocks.

For pipeline movements into the United States, CBP requires that a custody transfer meter on the pipeline be determined, and the importer must certify to CBP that the meter was installed in accordance with API or ASTM guidelines, that the meter is proved/calibrated on a basis in accordance with its usage, and that records relating to the installation, care and operation of the meter are stored in an organized manner and available for CBP's review upon request. As the importer is often times not the owner/operator of the meter, contracts between the meter owner and the importer are issued to convey the requirements.

In summary, API suggests that the volumes in the reporter's financial records be the basis of reporting or serve as an alternative monitoring requirement to be included in section 98.394 that would allow refineries, importers and exporters to use their existing accounting systems and quantities determined under the CBP program.

15. Exclusion of onshore oil and natural gas production from reporting

EPA discusses its decision to exclude onshore oil and natural gas exploration and production from the proposed MRR:

"Given the significance of fugitive emissions from the onshore petroleum and natural gas production, we would like to take comment on whether we should consider inclusion of this source category in the future. Specifically, we would like to take comment on viable ways to define a facility for onshore oil and gas production and to determine the responsible reporter. In addition, the Agency also requests comment on the merits and/or concerns with the corporate basin level reporting approach under consideration for onshore oil and gas production, as outlined below". (74 FR 68, page 16531)

<u>API Comments:</u>

API supports EPA's decision not to include "onshore oil and gas production" at this time. However, we note that the difficulty in inclusion of this portion of the industry is due to more than merely the difficulty in defining a facility. This segment of the industry is comprised of more than 739,000 domestic oil and gas wells (EIA 2006 data base) and more than 13,700 oil and gas operators (EIA data base 2007) in the US (with most of these onshore). This segment is also typified by complex operational, infrastructure, commercial and ownership arrangements, and the fact that many of the operators are small companies without significant resources, knowledge, and staff. Hence the difficulties of a broad inclusion of this industry segment into the reporting framework would pose difficulties that are much greater than simply the definition of a facility.

API recommends that should EPA decide to address GHG emissions reporting by this segment of the industry, it would have to be done through a subsequent rulemaking, with appropriate opportunity for review and comment. Based on API's analysis, the proposed framework for reporting from oil and natural gas systems, as currently reflected in Subpart W, is totally inadequate for the structure of the onshore exploration and production segment and would require a separate and distinct approach and should be done as a separate Subpart to the rule.

API urges EPA to continue its close collaboration with industry and other stakeholders in crafting requirements for this portion of the industry. Obviously, the techniques and methodologies employed will have to be carefully developed in order to yield a level of cost and burden commensurate with the emissions from this segment. API is participating in the ongoing effort, lead by the Western Regional Air Partnership (WRAP), to develop a GHG emissions reporting protocol for oil and natural gas industry exploration and production activities. This effort includes a broad range of stakeholders, including industry, governmental and non-governmental organizations – including EPA. If and when EPA would decide to include GHG reporting from this segment of the industry, the proposal should build on, and incorporate, the outcome from this collaborative protocol development effort.

Additionally, we would advise EPA that the methodologies selected and other reporting requirements would have to be very clear and easily implemented and be coupled with significant outreach, assistance, and development of simplified reporting tools, in order to assist the smaller operators, without exempting them from reporting. API is opposed to exclusion of small operators due to the competitive differential that this introduces into the industry.

16. Carbon Capture and Storage vs. Enhanced Oil Recovery

EPA is addressing a few issues related to Carbon Capture and Storage (CCS) in the preamble to Subpart PP.

a) *"We seek comment on the decision to exclude the reporting of fugitive CO_2 emissions from the CCS chain. We have concluded that there could be merit in requiring the reporting of fugitive emissions from geologic sequestration of CO_2".* (74 FR 68 16583)

API Comments

API supports the decision to exclude the reporting of fugitive CO_2 emissions from the CCS chain broadly and specifically does not believe there is merit in requiring the reporting of fugitive emissions from geologic sequestration of CO_2. API is concerned however that EPA does not appear to have a clear understanding of the behavior of CO_2 when it is injected (usually in a supercritical state) into a geologic formation.

EPA's discussion of the merits of reporting fugitive emissions from geologic sequestration suggests that EPA equates "retention rates" with the volume of CO_2 that is trapped in the geologic formation due to capillary trapping forces and that the remainder of the CO_2, the mobile portion, constitutes the potential fugitive emission. This is incorrect. Retention rate or storage rate should refer to the amount of CO_2 placed in a secure underground storage formation or that is used in and active EOR project at a given point in time. The CO_2 not trapped in the formation is produced with the oil and recycled through the system; it is not lost to the atmosphere. Importantly, each time the CO_2 is cycled through the field, additional CO_2 is trapped in the formation and new CO_2 is constantly needed to supplement the recycled CO_2 and maintain a constant injection volume at the EOR project.

In other words, of the amount of CO_2 initially injected in year zero, an increasing percentage will be retained in the formation with each cycling. The "retention rate" EPA refers to in the Preamble does not adequately capture this reality because new CO_2 is always being added to supplement that which is trapped in the formation. Additionally, evidence suggests that CO_2 injected via EOR wells in compliance with the UIC regulations does not leak into the surrounding groundwater (Smyth et al, 2008; Wilson and Monea, 2004) let alone the atmosphere (Klusman, 2003; Wilson and Monea, 2004). Exhibit 2 provides full citations.

Exhibit 2- CCS References Cited

- Smyth et al. (2008), Update on Studies on Risk to Aquifers from CO2 Sequestration Gulf Coast Carbon Center, Bureau of Economic Geology. [SACROC EOR project]
- Klusman (2003), A geochemical perspective and assessment of leakage potential for a mature carbon dioxide-enhanced oil recovery project and as a prototype for carbon dioxide sequestration: Rangely field, Colorado. American Association of Petroleum Geologists Bulletin, 87(9), 1485-1507 [Rangely EOR project]
- Wilson and Monea (editors) (2004), IEA GHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-2004 Petroleum Technology Research Center, Regina SK, Canada. [Weyburn EOR project]

b) *"We are not proposing the inclusion of geologic sequestration in the proposed rulemaking. However, the Agency recognizes that there may be significant stakeholder interest in reporting the amount of CO_2 injected and geologically sequestered at EOR operations in order to demonstrate the effectiveness of EOR projects that ultimately intend to store the CO_2 for long periods of time…we have outlined initial thoughts about how geologic sequestration* *might be included in a reporting program for EOR sequestration or other types of geologic sequestration. We welcome comment on the approach outlined below or other suggestions for how to quantify and verify the amount of CO_2 sequestered in geologic formations".* (74 FR 68, page 16584)

API Comments:

EPA is confusing the practice of EOR with the practice of geologic storage. While CO_2 is trapped in the hydrocarbon formation during EOR and permanently stored, that does not make the site a geologic storage site (i.e. one where the wells would be permitted under EPA's proposed Class VI rule) and should not impose on the EOR operator the requirements associated with operating a geologic storage site.

The information EPA is considering for EOR operators to submit is unreasonable. EPA is considering asking for data on fugitive emissions where there is no data to support the concept of fugitive emissions from an EOR site (see references in Exhibit 2) nor are there technologies available to reliably measure soil/air fluxes (this was clearly established at the EPA public workshop on Underground Injection of CO_2 in Feb. 2008 in Arlington, VA). Moreover, many of the requests are well beyond the scope of this rulemaking, such as requiring *"a map showing the modeled aerial extent of the CO_2 plume over the lifetime of the project"* and *"providing information which demonstrates sufficient storage capacity for the expected operating lifetime of the plant"* (74 FR 68 16584, emphasis added). Currently, these are not requirements for Class II EOR wells nor do they make any sense in a business-as-usual EOR context. Indeed, almost every item of requested information is not within scope of this rulemaking.

Consistent with the above comments on EOR, API does not believe the reporting rule should include CO_2 managed by CCS either since the intent of the reporting rule is to gather CO_2 emissions data to inform policy. Despite extensive study (e.g., Weyburn CO_2 Monitoring Project, SACS, CO2Store, etc.) the evidence is that there is no leakage associated with these types of operations (e.g. Weyburn, Sliepner, and In Salah). If in the future GHG emission reduction regulations are promulgated, offset credits should be granted to the quantity of CO_2 managed by CCS and tracked through the appropriate reporting mechanism.

III. EPA SOLICITED COMMENTS ON PROGRAM DESIGN AND GENERAL PROVISIONS

The comments below provide API's responses to EPA solicited feedback and other issues rrelated to overall program design and its general provisions.

1. Reporting threshold

EPA defines the reporting threshold generally as an annual facility wide actual emission level of 25,000 metric tonnes of CO_2E, unless otherwise specified. The draft preamble to the rule and supporting documents provide a detailed analysis of the impact of this threshold on different industry sectors, and support a conclusion that this threshold will result in covering approximately 85-90% of U.S. emissions.

"EPA is interested in receiving data and analyses on thresholds. In particular, we solicit comment on whether the thresholds proposed are appropriate for each source category or whether other emissions or capacity based thresholds should be applied.

If suggesting alternative thresholds, please discuss whether and how they would achieve broad emissions coverage and result in a reasonable number of reporters". (74 FR 68, page 16463)

API comments

API supports EPA's selection of the 25,000 metric tonnes CO_2E reporting threshold. API recognizes that this threshold is consistent with other GHG mandatory reporting programs, including that of the State of California. Any attempt to lowering the threshold to 10,000 metric tonnes CO_2E would create a huge burden on reporters and regulators alike by approximately doubling the number of affected facilities, while it will lead to inclusion of only an additional 1% of national emissions subject to the rule.

2. Rule effective Dates

EPA proposes to start data collection for calendar year 2010 with initial reporting due on March 31, 2011. EPA has requested comments on alternative schedules if the original goal cannot be met. EPA solicits specific comments on the following two options*:*

"Report 2010 data in 2011 using best available data: use either proposed methods or best available data for reporting; or Report 2011 data in 2012: delay rule implementation by a year". (74 FR 68, page16472)

API comments

As stated above, API backs collecting data that supports a specific policy development goal, and is of finite scope at this time. For such an approach, collecting best available data starting with 2010 calendar year operations, and lasting for no more than 3 years, would be acceptable. It is anticipated that final rulemaking for this reporting regulation will be in late 2009. The required systems and facilities to meet the currently proposed requirements cannot be in place to begin data collection at the start of 2010.

API is concerned that the proposed effective date of January 1, 2010, when the rule would probably be promulgated in the October/November 2009 timeframe, will not allow sufficient lead-time for implementation. If EPA insists on a January 1, 2010, effective date, it ought to design a phased-in system where the initial years would be a "pilot" period. This is consistent with the approach taken by the EU (three years pilot phase) and California (one year of 'best available data').

API cautions EPA that as written, compliance with the rule requirements and schedule is not possible and EPA must take some action to enable "day 1" compliance. EPA should consider industry's inability to install, test and calibrate all flow meters and other required instrumentation, including data archiving systems, within the short time that is expected between promulgation and effective dates.

EPA should also note that reporting emissions in 2010 based on "best available" information would not divert resources and attention from the work necessary for full rule implementation in the longer term.

3. **Reporting schedule**

EPA proposes a reporting system that is based on annual emissions by facility, and reporting separately by suppliers, importers and exporters of fuels and specified gases. The reports will be submitted annually on March 31st of each year for emissions from the previous calendar year.

EPA is interested in receiving input regarding the frequency and schedule of reporting:

"However, as future policies develop it may be necessary to reconsider the reporting frequency and require more or less frequent reporting (e.g., quarterly or every few years)." (74 FR 86, page 16472)

API comments

As outlined above, and during preliminary discussions with the EPA, API supports annual reports on a calendar year basis, with reports due 6-12 months after the close of each reporting year, for an initial program that is of finite duration and is designed to collect data for policy development.

The current proposal of having all calendar year data submitted to EPA by March 31st of the following year is not realistic. Three months is insufficient to collect all activity data that would be required to calculate emissions, conduct internal reviews and quality assurance checks of the data, and certify the data by a designated company representative, and submit to EPA. Other reporting programs allow longer time intervals for reporting (e.g., six months for the Toxics Release Inventory (TRI), and five months for California's mandatory GHG reporting). API recommends that the report date be no earlier than June 30th of each year.

API is concerned about the EPA proposed deadlines for reporting of February 28th for fuel supply and March 31st for facility emissions. These deadlines are not realistic given the large amount of data and supporting information that needs to be collected, assembled, reviewed and certified internally by companies prior to reporting. API recommends that the report date be no earlier than June 30th**.**

4. **Program Duration**

EPA discusses its consideration of a multi-year program that would sunset absent subsequent regulatory action by EPA to extend it. However, it decided that it is premature to determine this now.

"EPA solicits input on whether the duration selected by EPA is appropriate for each source category or whether an alternative approach should be adopted". (74 FR 68, page 16463)

*"EPA crafted the requirements in this rule with the potential monitoring, recordkeeping and reporting requirements for any future regulations addressing GHG emissions in mind. EPA solicits comment on all of these possible approaches, including whether EPA should commit to revisit the continued necessity of the reporting program at a future date". (*Preamble page 160)

API comments

API previously advised EPA that as an initial data collection designed to guide policy decisions, reporting requirements under this rule should be of a finite duration, perhaps lasting no more than three years.

With this unprecedented use of the authority of Section 114, EPA ought to review the necessity of an on-going data collection program. There seems to be a need for an interim program, as stated above, but such a program should either sunset, or be amended, as appropriate, to meet the needs of future regulatory frameworks when promulgated.

5. Level of Reporting

EPA requires reporting at the facility level, since it concluded that corporate level reporting is too complex for mandatory reporting,

"Although many voluntary programs such as Climate Leaders or TCR have corporate-level reporting systems, EPA concluded that corporate-level reporting is overly complex under a mandatory system involving many reporters and thus is not appropriate for this rule, except where discussed below. Complex ownership structures and the frequent changes in ownership structure make it difficult to establish accountability over time and ensure consistent and uniform data collection at the facility-level". (74 FR 68, page 16470)

An exception to facility level reporting is for some supplier source categories (e.g., importers of fuels and industrial GHGs). Since importers are not individual facilities in the traditional sense of the word, this reporting responsibility would be vested with corporate ownership.

API comments

Consistent corporate level reporting is illustrated in the API/IPIECA "Petroleum Industry GHG Reporting Guidelines". These industry guidelines provide the necessary guidance for corporate level reporting and are used by the industry sector worldwide. However, for the purposed of this data collection, facility-wide reporting would be acceptable, provided it does not require further detail at the individual device and source level. Additionally, reporting should be limited to direct GHG emissions under the direct operational control of the reporting facility.

For fuel suppliers, the information collected should be limited to the corporate level without reporting at the individual facility level.

Adopting a more aggregated reporting approach would relieve some of the reporting and data confidentiality issues and could be better aligned with fuels movement reports already provided to other agencies of the federal government.

6. Rule Applicability

EPA proposes reporting thresholds that are generally equivalent to a threshold of 25,000 metric tons of CO_2E per year of *actual emissions*. EPA defines broad categories for rule applicability: some sectors are all in (i.e., petroleum refineries); some only if they exceed the threshold (i.e., oil and natural gas systems, hydrogen production); some only major stationary combustion sources, and some that are not reporting at all.

EPA recognizes that a potentially large number of facilities would need to calculate GHG emissions in order to determine whether or not they have to report.

For facilities that contain only large combustion sources, EPA proposes to add a capacity threshold in addition to the actual emissions threshold. EPA defines such a capacity threshold as any facility with an aggregate maximum rated heat input capacity of less than 30 MMBtu/hr.

EPA seeks comments about:

"… the need for developing simplified emissions calculation tools for certain source categories to assist potential reporters in determining applicability.

These simplified calculation tools would provide conservatively high emission estimates as an aid in identifying facilities that could be subject to the rule. Actual facility applicability would be determined using the methods presented for each source category in the rule". (74 FR 68, page 16470)

In addition to feedback about the capacity threshold proposed:

a) *"The presumption for maximum rated heat input capacity of 30 MMBtu/hr is appropriate,*

b) *A different (lower or higher) MMBtu/hr capacity presumption should be set and*

c) *Other capacity thresholds should be developed for different types of facilities. The comments should contain data and analysis to support the use of different thresholds.*

API comments

EPA should develop an applicability-screening tool for facilities, particularly for those source categories whose applicability threshold is based on an aggregation of combustion emissions (subpart C) and industry segment specific emissions (such as in subparts J, P, and in particular W).

API is concerned about the burden that will be imposed on some sectors, such as oil and natural gas systems, or other industry sectors where the applicability determination hinges on total emissions from combustion and non-combustion sources. Companies in these sectors will have to undertake extensive data collection and measurements just to demonstrate non-applicability of their facilities under this rule.

API supports the development of sector appropriate screening tools to facilitate this applicability determination and reduce burden when determining facility applicability. For example, in the API Compendium a range of conservative screening methods are provided for oil and natural gas systems, including compressor stations. These methods are geared for high-level emission estimates on a facility type basis and could be the basis for such a simplified approach.

API proposes to work collaboratively with EPA to develop screening tools that are applicable for the oil and natural gas sector. Such tools will use simplified methods to determine applicability and will be developed in consultation with API members, and in collaboration with EPA technical staff.

If a facility applies the screening tool according to EPA instructions and reaches the conclusion that they are not subject to reporting under the rule, the facility shall not be subject to enforcement should later-developed information indicate that the facility would have been above the applicable threshold.

In addition API suggests that 30 MMBtu/hr as the maximum capacity for exclusion for combustion only reporting is not appropriate. A better maximum rated heat capacity figure would be 40MMBtu/hr: This corresponds to a unit – or combination of units - that are fired at full load for 24 hours per day and 365 days per year, that would result in emissions of 18,600 to 26,700 tonnes of CO2 per year, assuming a range of fossil fuels of increasing density, from Natural Gas to Fuel Oil #4, respectively. If one takes into account that typical loads on most combustion devices are closer to 80%, than these emissions will actually be in the range of 14,900 to 21,400 metric tonnes of CO2 per year, respectively.

Since EPA wants to base the rule applicability on actual emissions, and since the 40MMBtu/hr cutoff has precedence in other federal regulations, API would recommend that this level be selected for mandatory reporting for those facilities that are subject only to subpart C requirements.

7. 'Once in always in'

EPA proposes that once a facility is over the applicability threshold and is included in the program it will continue to report even though if the facility GHG emissions might drop below the applicability threshold. EPA requests comment on whether it should develop a process, similar to that available in the California GHG mandatory reporting program:

"Comments should include specifics on how the exemption process could work, e.g., the number of years a facility is under the threshold before they could be exempt, the quantity of emissions reductions required before a facility could be exempt, whether a facility should formally apply to EPA for an exemption or if it is automatic, etc". (74 FR 68, page 16470)

API Comments

API alerted EPA to the fact that facilities might inadvertently find themselves over the threshold based on the initial applicability determination, and the absence of a screening tool that can be used for those facilities that might be on the margins of applicability. EPA ought to account for the fact that companies have on-going programs to increase efficiency and reduce GHG emissions, and that emissions might be declining naturally due to the dynamic nature of a resource based industry. Inclusion of the "once in always in" provision in the rule would act as a disincentive to voluntary emissions reductions, since facilities that did lower their emissions below the threshold would have to continue to report.

API would support establishing a process, similar to that provided by California regulations, which offers a facility an option for exiting from the reporting program. The rule should incorporate exit criteria, such as facility emissions that are reported to be under the applicability threshold for two to three consecutive years. Re-entry to the program should modifications to the facility or operations cause emissions to rise above the applicability threshold would be handled as described in the proposed rule.

The rule should provide a mechanism for facilities making permanent changes, such as removing equipment from their site, to notify EPA and end reporting. Should later modifications to the facility result in emissions greater than the applicability threshold re-entry would be handled as described in the proposed rule.

8. Emission Calculation Methodologies

EPA proposes specific methodologies for direct measurements of emissions and key parameters in order to calculate GHGs emissions for the covered sectors. EPA specifies that emissions should be calculated and reported only for those sources for which methods are provided in the applicable subparts. EPA is interested in receiving data and other technical information relevant to their method selection approach:

"We solicit comment on whether the methodologies selected by EPA are appropriate for each source category or whether alternative approaches should be adopted".

If suggesting an alternative methodology (e.g., using established industry default factors or allowing industry groups to propose an industry specific emission factor to EPA), please discuss whether and how it provides complete and accurate emissions data, comparable to other source categories, and also reflects broadly agreed upon calculation procedures for that source category". (74 FR 68, page 16461)

API comments

API previously commented to EPA that the reporting program ought to be consistent with, and adopt elements from, existing reporting protocols and guidelines, such as the API Compendium of GHG Emission Methodologies for the Oil & Gas Industry. The guidance provided by the API Compendium comprises robust, consistent and evergreen methods that are based on best available data, and API is pleased to note that EPA is citing this document as one of its references for developing the GHG calculation methods for this rule.

The methods provided by the API Compendium are endorsed broadly by the worldwide oil and natural gas industry, and many companies have already incorporated them into their GHG estimation and reporting endeavors. The API Compendium is maintained evergreen and its 2009 Edition will be published in June 2009.

Some of the revisions contained in the 2009 Edition, which are of particular relevance to this rulemaking, include an expanded discussion of emission estimation approaches for sources such as: dehydration operations, acid gas removal, tank flashing, pneumatic devices, hydrogen plants, catalytic cracking units, asphalt blowing, and wastewater treatment. The 2009 API Compendium will also include updated referenced emission factors data to represent 95% confidence intervals, where data were available to make these revisions, such as for the 1996 EPA/GRI methane emissions characterization study.

EPA adoption of the methods outlined in the API Compendium for the various source categories and segments of the industry, would result in well documented, accurate and consistent GHG reporting and contribute to minimizing the extra burden this proposed rule is imposing on the industry, as discussed above.

In many places the rule has specified only one methodology; many methods might be applicable with equivalent accuracy with lower data gathering. Specific comments to applicable methodologies are provided in Section IV below under the specific subparts.

In other air programs multiple methods are allowed. The same flexibility should be afforded to GHG reporting. API has been engaged in GHG emission calculation methodology development for over a decade and is aware of the dynamic nature of the field and the emergence of new measurements and estimation techniques. Therefore it is imperative that EPA should provide a clear and efficient method for approval of alternatives to the methods prescribed in the proposed rule.

9. Reporting supplemental information

In addition to reporting GHG emissions from applicable facilities, EPA proposes a long list of additional informational items that would have to be reported by all facilities. EPA contends that the information proposed for reporting is needed to support the analyses of GHG emissions for future policy development and ensure that data are accurate and comparable across source categories:

"Besides total facility emissions, it benefits policymakers to understand the specific sources of the emissions and the amounts emitted by each unit/process to effectively interpret the data, and the effect of different processes, fuels, and feedstocks on emissions"". (74 FR 68, page 16472)

API comments

API does not agree with EPA's contention that this level of reporting would not be overly burdensome since many of these data are already routinely recorded by facilities for business reasons. The information requested is of such a detailed nature - and of such a set format - that would probably not be compatible with what all facilities track and record as part of their day-to-day business operations. Even for data already collected, entities have to organize, format, review and certify internally, prior to reporting to EPA, which would be a major undertaking.

In addition, reporting such a large volume of data would probably overwhelm the EPA reviewers and would increase the potential for mishandling of confidential business information.

10. "Designated Representative"

EPA proposes that each reporting facility have a 'designated representative' that is approved by all facility owners and who can certify the emissions data provided to EPA. As such this "Designated Representative" would act as a legal representative between the reporting facility or entity and the EPA:

"The use of the Designated Representative would simplify the administration of the program while ensuring the accountability of an owner or operator for emission reports and other requirements of the mandatory GHG reporting rule.

The Designated Representative would certify that data submitted are complete, true, and accurate.

The Designated Representative could appoint an alternate to act on their behalf, but the Designated Representative would maintain legal responsibility for the submission of complete, true, and accurate emissions data and supplemental data. (74 FR 68, page 16473)

API comments

The proposed rule sets an unrealistic expectation for the role of the designated representative.

40 CFR 98.4(e)(1) includes a certification statement containing the following language:

"...I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete…"

This language sets an inappropriate standard for a plant manager, or his/her "designated representative." No high-level management official at a complex facility has the time or expertise to *"personally examine"* all the documents used to prepare the emissions report. This could in essence be a full-time job (or more) and would distract from other management responsibilities. A more appropriate standard is one that is similar to other EPA air programs, which is based on a *"reasonable inquiry"* approach.

In the TRI program, which is another emissions reporting rule, the certification statement in 40 CFR 372.85(b)(2) is *"I hereby certify that I have reviewed the attached documents and, to the best of my knowledge and belief, the submitted information is true and complete and that amounts and values in this report are accurate based upon reasonable estimates using data available to the preparer of the report."*

The provisions for the "alternate designated representative" set an inappropriate obligation on the original "designated representative." The proposed rule allows for the designated representative to delegate responsibility to an alternative designate representative. For example, the designated representative might be on vacation or a medical leave. However, the rule language in 98.4(f)(1) states that *"...any representation, action, inaction, or submission by the alternate designate representative shall be deemed to be a representation, action, inaction or submission by the designated representative."* API recommends that 98.4(f)(1) be deleted - the responsibility should lie with the alternate designate representative.

Additionally, designated representatives might not have the detailed expertise to evaluate data and emissions from all of the processes of large complex facilities for which they are reviewing data.

The proposed rule requires the certificate of representation, to be revised if the designated representative changes. These provisions are not necessary and just create a paperwork exercise. Considering the frequency of personnel changes, having facilities send in updated certificates of representation provides no value. API recommends that EPA consider a more generalized certificate of representation, such as "plant manager or their delegated representative".

The rule should provide for the case where non-operating "owners" decline to approve, in writing, the "Designation of Representative" per EPA's requirement of having a legally binding agreements. Also, EPA should provide for a longer notification period for facilities to submit "change of ownership" updates to EPA.

Some of the possible contentious issues associated with facility owners agreeing to a "designated representatives" might be associated with unintended consequences of EPA discussion of liability for data corrections using missing data. (Further discussion of these issues is provided in III.12. below).

API recommends that the requirements and responsibilities of the designated representative be amended to be consistent with the certification requirements in other established environmental reporting and information gathering programs such as the Toxics Release Inventory program. Please see Section IV for our specific recommendations for amending proposed 40 C.F.R. § 98.4..

11. De minimis Reporting for Minor Emission Points

EPA recognizes that a number of existing GHG emission reporting programs contain ‘‘de minimis’’ provisions to reduce the burden for smaller emission sources within facilities that are subject to reporting. EPA acknowledges that existing programs include such provisions to avoid imposing excessive reporting costs on minor emission points that can be burdensome or infeasible to monitor.

However, EPA contends that under its program design there is *no need to exclude a percentage of emissions from reporting under the proposed rule.* The rationale provided is:

a) Only facilities over the established thresholds would be required to report;
b) For facilities subject to the rule, only emissions from those source categories for which methods are provided would be reported; and
c) Some facilities subject to the rule could still have some relatively small sources, but the proposed rule includes simplified methods for smaller sources, where appropriate.

EPA is seeking comments on its rationale of not providing for deminimis reporting in the proposed rule,

“EPA requests comment on whether this approach to smaller sources of emissions is appropriate or if we should include some type of de minimis provision.” (74 FR 68, page 16473)

API comments

In previous communication with the EPA, API maintained that the reporting program should be designed in such a way that once the reporting threshold is triggered, the reporting rule should allow up to 5% of the emissions to be declared as “deminimis”, allowing simplified emission estimation methods for demonstrating compliance with this emission level.

Most existing GHG reporting programs recognize that it may not be possible, or efficient, to specify the reporting methods for every source that must be reported. Reporting programs also recognize that typical uncertainty ranges associated with GHG emissions data make it infeasible that reported information could attain better than 95% accuracy for the reported information.

Most other programs have some type of provision to reduce the burden for smaller emissions sources. Depending on the program, the reporter is allowed to either not report a subset of emissions (e.g., 2 to 5% of facility-level emissions) or use simplified calculation methods for such de minimis sources. Therefore, EPA’s rationale for not providing a deminimis reporting level for minor emissions sources is not justified

API contends that EPA - when finalizing this rule - should adopt a practical approach and define a de minimis level for simplified reporting, using engineering assessment with no monitoring requirements, and without being subject to enforcement action. Otherwise companies might end up spending over 50% of their resources in trying to determine emissions from sources that contribute less than 5% to the overall facility GHG emissions.

A specific case in point for refining is the definition of “process vents.” This definition is vague and could be interpreted as all-inclusive of any vent not otherwise specified by the rule. Requiring reporting for these vents negates EPA’s contention that only source specific categories, for which methodologies are provided, are to be included.

Therefore, for facilities that are subject to the rule, EPA should also define a simplified approach for small and insignificant sources within a reporting facility that could be declared as "de minimis".

A de minimis approach is featured in most, if not all, GHG reporting regulations, due to the recognition that many complex facilities have a myriad of equipment and small sources of emissions, in addition to their larger sources. API recommends that EPA adopts a 5% de minimis cut-off level and define simplified methods that can be used to demonstrate this exclusion.

Example of small sources whose emissions would fall under the deminimis category in many instances is provided under the detailed technical comments in Section V below.

12. Missing data procedures and recalculations

EPA is considering whether or not to include provisions to require facilities to correct previously submitted data, under certain circumstances, and is referencing the procedure available in the California mandatory GHG reporting rule:

"EPA is seeking comment on whether to include a provision to require a minimum standard for reported data (e.g., only 10% of the data reported can be generated using missing data procedures)".

It goes on to say:

"Even if EPA were to allow recalculation of submitted data or accept data submitted using missing data procedures, that would not relieve the reporter of their obligation to report data that are complete, accurate, and in accordance with the requirements of this rule. Although submitting recalculated data or data using missing data procedures would correct the data that was wrong that resubmission or missing data procedures does not necessarily reverse the potential rule violation and would not relieve the reporter of any penalties associated with that violation." (74 FR 68, page 16474)

API comments

EPA's proposed approach is not comparable to the California data recalculation example. The California provision was crafted within the context of a system that relies on third-party verification, where data corrections are permitted - *without penalty* - following the auditors' review of the preliminary data submitted during a reporting cycle. Corrected inventories are to be submitted following the comments received from verifiers to close the verification cycle. *See* 7 C.C.R. § 95104(d) (allowing revision of a data report if, during the course of receiving verification services and prior to completion of a verification opinion, an operator chooses to make a correction or improvement).

For the proposed rule, EPA has proposed self-certification with EPA verification. The agency contends that submitting recalculated data or data using missing data procedures would *"not necessarily reverse the potential rule violation and would not relieve the reporter of any penalties associated with that violation"* (74 FR 68, page 16474). Such an approach is unwarranted because it would penalize companies that, through independent verification efforts or through improvements to monitoring mechanisms, are able to improve their data. The rule should not be crafted in a way that creates a disincentive to improve the accuracy of the data reported through such efforts.

API contends that for the purpose of this reporting rule, rule violation should be defined as non-reporting, late reporting, or egregious violation of reporting procedures. Mere recalculation due to inadvertent mistakes or filling-in missing data for a set percentage of data loss should not be considered a violation. Especially given that the primary purpose behind the proposed rule is accurate data collection for the purposes of informing future agency actions, facilities should be permitted the flexibility to resubmit information that was identified as incorrect without ramifications. EPA should specifically stipulate that facilities (and their representatives) would have no liability if they follow the missing data procedures that are specifically outlined in the rule.

Hence, if the final rule would require submission of missing and/or recalculated it should state and make clear that such a recalculation or a revision of a previously submitted report shall not be considered evidence that any prior report is in noncompliance with the rule.

13. Monitoring Requirements

EPA discusses its consideration of four broad approaches to monitoring requirements in support of mandatory reporting of GHG under this rule:

Option 1. Direct Emission Measurement

Option 2. Combination of Direct Emission Measurement and Facility-Specific Calculations

Option 3. Simplified Calculation Methods

Option 4. Reporter's Choice of Methods

EPA is seeking comments on its selection of Option 2, described above*:*

"EPA requests comments on the selected monitoring approach and on other potential options and their advantages and disadvantages". (74 FR 68, page 16475)

<u>API comments</u>

Consistent with previous API comments, and one of API's general design principles, this reporting rule should not impose any new measurement requirements but rather allow reporters to utilize their best available data. In particular, imposing capital expenditures and mandating overly burdensome operating expenses, tied to the proposed reporting requirements, are incongruous with previous data collections under Section 114 of the CAA.

The requirements for measurements and monitoring should be established within the context of a forthcoming regulatory framework that will address climate change and define GHG mitigation efforts.

The API Compendium uses 'decision trees' to guide the users to applicable calculation methods within the constraints of available data. A similar approach is recommended for this rule where reporters could be guided to use – transparently - their best available data, without overburdening them with monitoring requirements and capital and operational expenditures. Such an approach would be more in line with the legislative intent for developing this reporting rule, without overstepping its boundaries by speculating what future requirements might entail.

API is providing below additional specific comments on the monitoring requirements under each of the appropriate subparts to the rule, but would like to emphasize a major discrepancy between the preamble discussion and the rule language under Subpart C:

– The preamble states that continuous emission monitoring systems (CEMS) are only required for combustion devices fired by solid fuels, as listed in Table C-1 on page 16481;
– The rule language regarding selection of the "Tier" level for monitoring and measurement methods does not reflect the discussion and intent in the preamble;
– Section 98.33 (b)(5), as currently written, would require CEMS for any combustion unit that ran for more than 1,000 hours in any year since 2005;
– There seems to be some syntax omissions, including some "and" and "or" omissions in the current rule language. These omissions seem to contravene the preamble intent as summarized in Table C-1.

API is providing in Exhibit 3 below an excerpt of the rule language with specific edits (in red) for amending the rule language to reflect the intent and rationale presented in the preamble, and as summarized in Table C-1 (74 FR 68, page 16481).

Exhibit 3 – Recommended rule language amendment
(74 FR 16634, April 10, 2009)

(b) Use of the four tiers.

…….

(5) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used for a unit if:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW, and
(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel, and
(C) The unit has operated for more than 1,000 hours in any calendar year since 2005, or
(D) The unit meets the criteria in (B) and (C) directly above, and
(E) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit, and
(F) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program, and
(G) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit:

(A) Has both a stack gas volumetric flow rate monitor and a CO2 concentration monitor, and
(B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) and (C) of this section, and
(C) The CO2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section.

14. Fugitive Emissions Definition (Subpart W)

EPA states in the preamble,

"For this rulemaking, fugitive emissions from the petroleum and natural gas industry are defined as unintentional equipment emissions and intentional or designed releases of CH4-and/or CO2-containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. In the context of this rule, fugitive emissions also mean CO2 emissions resulting from combustion of natural gas in flares. These emissions are hereafter collectively referred to as ''fugitive emissions'' or ''emissions''. We seek comment on the proposed definition of fugitives, which is derived from the definition of fugitive emissions outlined in the 2006 IPCC Guidelines for National GHG Inventories, and is often used in the development of GHG inventories. We acknowledge that there are multiple definitions for fugitives, for example, defining the term fugitives to include ''those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening''. According to the 2008 U.S. Inventory, total fugitive emissions of CH4 and CO2 from the natural gas and petroleum industry were 160 metric tons CO2e in 2006. The breakdown of these fugitive emissions is shown in Table W–1 of this preamble". (74 FR 68, page 16529)

API Comments:

API does not support EPA definition of fugitive emissions in Subpart W. The definition is not appropriate and results in requirements for monitoring, measurement, and reporting that are overly burdensome, costly, inappropriate, and unnecessary.

The proposed rule's definition of fugitives is confusing and inconsistent with industry guidance such as the API Compendium, common industry and agency practice, and existing federal rules such as 40 CFR 52.21(i)(20) and 40 CFR 63.2, which state *"Fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening."* EPA's broad use of *"fugitive emissions"* results in the application of emission methodologies that are not appropriate for vented and/or flared emission sources. API requests that EPA revert to the classical definition of fugitive emissions in conformance with other CAA programs and then list (already mostly done) the individual process blowdowns, and flare sources that are also included within the scope of Subpart W.

API requests EPA address process and vented emissions using estimation methods and factors appropriate to these source types and characteristics, as documented in Section 5 of the API Compendium. In addition, flares should not be considered a fugitive emission source, and should instead be addressed as a combustion emission source. EPA seems prone to this same confusion within the rule itself as evidenced by 98.232 (a) where individual process and flare type sources (acid gas vents, dehydrator vent stacks, flare stacks, etc.) are listed along with broad categories such as "Processing facility fugitive emissions".

Also, the fugitive emissions definition should not result in an expansion of the current CAA regulatory definition of fugitive emissions by including the phrase "unintentional" emissions.

15. Leak Detection and Quantification Requirements (Subpart W)

EPA describes its selection of monitoring methods for fugitive emissions from oil and natural gas systems sources, *"Each fugitive emissions source would be required to be monitored using one of the two monitoring methods: (1) Direct measurement or (2) engineering estimation. Table W–3 of this preamble provides the proposed fugitive emissions source and corresponding monitoring methods. General guidance on the monitoring methods is given below".*

Table W-3 goes on to specify that direct measurements will be required for:

- Centrifugal Compressor Dry Seals,
- Centrifugal Compressor Wet Seals,
- Compressor Fugitive Emissions,
- Non-pneumatic Pumps,
- Offshore Platform Pipeline Fugitive Emissions,
- Open-ended Lines,
- Pump Seals, Facility Fugitive Emissions, and
- Reciprocating Compressor Rod Packing.

API Comments

API does not support EPA's requirements for leak detection and subsequent quantification as detailed in Subpart W. API requests that EPA replace these requirements with a component count (based on physical count or engineering estimate) and emission factor approach for "normally defined" (see comment II.14 directly above) fugitive emissions.

EPA proposes that the fugitive emissions from some sources be detected using optical or other analyzers and then quantified by direct measurement using high volume samplers, calibrated bags, or meters. EPA justifies their requirements for annual leak detection and subsequent quantification of identified leaks with the following statements in the Preamble and Technical Support Document:

> *"There have been no subsequent comparable studies published to replace or revise the fugitive emissions estimates available from this study."* (Preamble)
>
> *"There are several estimates of emissions factors for emissions sources that do not correctly reflect the operational practices of today."* (Subpart W TSD – page 18)

The approach proposed by EPA is onerous, costly, and offers little additional benefit over the use of component counts (physical count or engineering estimate) and emission factors, and is not justified in either the Technical Support Document (TSD) or Preamble discussions for Subpart W. API does not believe these statements are accurate and should not be the justification for the burdensome requirements in the proposed rule.

According to EPA's technical support document for Subpart W, EPA relied solely on the GRI/EPA study of 1992 (published in 1996) and did not include later studies that are more current and relevant to this rule making. In particular, EPA did not include several EPA sponsored studies, including:

- EPA Phase I and Phase II Studies (EPA Grant No: 827754-01-0), *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*), and

- EPA, PRCI, GRI transmission station study (EPA Grant N/A), *Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations.*

The Phase I and II studies measured fugitive emissions at nine gas processing facilities and seven compressor stations (in excess of 207,000 components), while the second set of studies included monitoring of more than 35,000 components at natural gas transmission stations. The results of neither of these studies, and others, were not included in the EPA analysis of fugitive emission studies and available field data.

In the TSD, EPA lists five specific source types where they feel the uncertainty is large – these being "Condensate and oil storage tanks"; "Natural gas well workovers"; "Natural gas well completions"; "Natural gas well blowdowns"; and Flares." It is noted that of these specifically listed source types only two of them are within the scope of the currently proposed rule yet many condensate tanks at gas processing facilities and offshore production facilities have emission controls (VRU's and/or thermal destruction) already installed. Also in many gas processing and offshore production facilities permanent flare velocity and/or flow meters are installed (although that this is not uniform throughout the industry). These facts eliminate much of EPA's expressed concern regarding the quality of current emission estimates.

By requiring the direct measurement of fugitive emissions and not providing any alternative means to inventory these small emissions, EPA has imposed a disproportionate and inappropriate burden on the oil and natural gas systems industry which is not based on analysis of information and studies which were conducted with EPA's support and involvement. In view of EPA's exclusion of the two studies noted above and potentially other studies, this burden is not justified and EPA's analysis is deficient.

EPA currently has an active study underway with the University of Texas leading to improve the fugitive emission factors for the Oil and Gas industry that is scheduled for completion in about three years. Industry is actively participating in and supporting this work – as they have the prior studies.

As an alternative to the prescribed annual leak detection and subsequent quantification of identified leaking sources, EPA should incorporate the studies noted above and allow fugitive emission estimation and reporting based on component counts (either physical or engineering estimated) and emission factors derived from incorporation of more current and relevant studies.

It also appears that EPA significantly underestimated the cost of the required leak detection and quantification although, due to the short comment period allowed for the rule, detailed analysis of cost estimates for this work have not been possible. As API indicated in Section II above it will share the results of its cost survey with the EPA as soon as data are available, probably in the July 2009 time period.

Even ahead of the results of the cost survey, API members know from their experience that the costs to simply perform leak detection using IR technology are not trivial. When the costs of managing bag or volume samplers for emissions quantification are also considered, the fugitive measurement costs quickly grow substantially.

In view of these discussion, and additional technical details provided in Section V under Subpart W comments, API requests that the proposed requirements for direct measurements indicated in Table W-3 be substantially revised when the final rule is promulgated, and flexibility be afforded to reporters to use either direct measurements or engineering analysis for all sources that require reporting under subpart W.

16. Recordkeeping requirements

EPA proposes that each facility subject to annual GHG reporting keep an extensive set of records in addition to its GHG inventory data. Each facility would be required to retain all required records for at least five years. It also stipulates that,

"The allowance of a variety of electronic and hard copy formats for records allows flexibility for facilities to use a system that meets their needs and is consistent with other facility records maintenance practices, thereby minimizing the recordkeeping burden". (74 FR 68, page 16476)

API comments:

Although EPA is not soliciting specific feedback on the issue, API would like to address this within the context of the extra burden and complicated logistics that would be required in view of all the supplemental reporting and recordkeeping requirements. Despite the flexibility noted by EPA due to the variety of formats acceptable for recordkeeping, the large volume of records required is not amenable to storage at remote field locations, such that the records could be immediately accessible for potential on-site inspections.

In order to maintain accurate records and back-up documentation for demonstrating compliance, companies will have to rely on data centers and centralized archiving procedures in support of such remote locations as offshore production platforms, compressor stations, fuel supply terminals, to name just a few.

API is recommending that EPA tailor the documentation and recordkeeping procedures – for this rule – to be compatible with other ICRs under Section 114. EPA would have the opportunity to reevaluate its documentation and recordkeeping requirements at the time of promulgating potential future GHG mitigation regulations.

In 98.3(g), EPA proposes records be kept that contain the *"names and documentation of key facility personnel involved in calculating and reporting the GHG emissions"* and a *"log book documenting any procedural changes to the GHG emissions accounting methods and any changes to the instrumentation critical to the GHG emissions calculations."* These two requirements are vague and thus overly broad. In the case of the former, many personnel are arguably involved in calculating and reporting the GHG emissions from the programmer who set up the systems to monitor, calculate, and record values to the administrative assistant who helped with the report's mailing. In the case of the latter, it too is vague and overly broad. In the first place, "any changes to instrumentation" has no limitation in application. Secondly, the requirement to keep a log of "procedural changes" is duplicative given the requirement to record the "GHG emissions calculations and methods." For these reasons, we request that these two items be either removed or limited in scope.

IV. DETAILED LEGAL COMMENTS

The comments below provide detailed legal analysis of overarching issues raised previously in Sections II and III.

1. **Legislative authority**

EPA asserts that it developed the proposed reporting requirements based on existing authority under Clean Air Act ("CAA") Sections 114 and 208. *See* 74 Fed. Reg. 16448, 16454-55 (April 10, 2009). EPA, however, is over-reaching this authority, which does not authorize it to require the proposed indefinite monitoring, recordkeeping, and reporting from most sectors of the economy regarding emissions with a currently uncertain regulatory status. At a minimum, none of EPA's stated purposes for the data justify the frequency and duration of the reporting requirements, or the imposition of burdensome new measurement protocols and the installation of extensive and expensive instrumentation. Further, EPA already has in its possession and continues to collect detailed GHG emissions inventory data that is sufficient to meet the stated purposes the Agency asserts underlie the proposed rule.

In its preamble, EPA suggests it is appropriate to gather information required under the proposed rule because the information may be relevant to EPA implementing a variety of CAA provisions. The Agency asserts that the phrase "carrying out any provision of the Act" is "quite broad" and, therefore, "Given the broad scope of sections 114 and 208 of the CAA, it is appropriate for EPA to gather the information required by this rule because such information is relevant to EPA's carrying out a wide variety of CAA provisions." *Id*. at 16454. EPA suggests "for example" that such information may be used to inform decisions about whether and how to regulate GHG emissions under a variety of CAA authorities (such as Sections 111, 202, 211, 213, 231, and PSD) and may help the Agency implement non-regulatory strategies for preventing or reducing air pollutants. *Id*. at 16454 and 16455. EPA concludes by suggesting that these possible uses are not a complete list of the "possible ways" the information could "assist" the Agency; rather, they simply "illustrate[] how the information request fits within the parameters of EPA's CAA authority." *Id*.

To begin, these generalized suppositions as to how the information *might* be used at some indeterminate time in the future provide wholly inadequate justification for an information request of the size, scope, and duration that EPA has proposed. EPA has a fundamental obligation to assert a rational basis for implementing its authority under Sections 114 and 208, which includes in this case a particularized explanation of the reasons EPA actually, currently needs this information (versus a "wish list" of programs and policies that *might* be "informed" by gathering this information). In short, the proposal provides no clear, specific, and ascertainable explanation of why this information is needed and how it will be used and, thus, the rule stands to be an unreasonable and arbitrary exercise of Section 114 and 208 authority.

Moreover, the agency's reading of its authority under Sections 114 and 208 is overly broad and would improperly render meaningless the limitations in those provisions. EPA emphasizes that information may be required under Section 114 for purposes of "carrying out any provision" of the Act, with an exception for Title II provisions pertaining to fuels and mobile sources. 74 Fed. Reg. at 16454.

Section 114, however, must be read in light of the entire statute, which makes clear that the data collection it authorizes is limited to only certain persons that are subject to the Act's requirements. 42 U.S.C. § 7414(a)(1) (limiting Section 114 applicability to "any person who owns or operates any emission source, who manufactures emission control equipment or process equipment, who the Administrator believes may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter (except a provision of subchapter II . . .)"). The applicability of Section 114 is thus limited to entities who own or operate an emission source or who are subject to regulation under the CAA for a given air pollutant. EPA's attempt to collect data under Section 114 from persons who are not owners or operators of an emission source or who are not subject to regulation under the CAA exceeds Section 114's authority and is improper.[1] It is a fundamental rule of statutory construction that statutes should not be interpreted in a manner so as to make any phrase redundant. *See, e.g., Gustafson v. Alloyd Co., Inc.*, 513 U.S. 561, 574 (1995) ("the Court will avoid a reading which renders some words altogether redundant"); *Zimmerman v. Cambridge Credit Counseling Corp.*, 409 F.3d 473, 476 (1st Cir. 2005) ("no construction should be adopted which would render statutory words or phrases meaningless, redundant, or superfluous."); *U.S. v. Hovsepian,* 359 F.3d 1144, 1160 (9th Cir. 2004) ("We interpret statutes so as to avoid making any phrase meaningless or unnecessary.").

EPA's interpretation of Section 114 ignores and violates this well established canon by requiring indefinite data collection from *any person* based on the vague stated purpose of "carrying out any provision" of the Act. EPA cannot expand such authority beyond the express limitations of Section 114, and permit that single phrase to swallow the express limitations of the entire rule. In addition, the proposed reporting requirements exceed this Section 114 authority to "…undertake monitoring…[and]…sample emissions…as the Administrator may **reasonably** require," 42 U.S.C. § 7414(a)(1) (emphasis added), because they would unreasonably require the installation and maintenance of extensive and expensive GHG monitoring instrumentation.

Clearly, EPA's decision to propose a GHG reporting rule is motivated by the 2008 Consolidated Appropriations Act, signed into law on December 26, 2007. Consolidated Appropriations Act, 2008, P.L. 110-161, 121 Stat. 1844, 2128 (2008) ("Appropriations Act"). This Act authorized one-time funding "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 greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States." *Id.* The straightforward point of the appropriations bill provision is to have EPA administer the collection of data; Congress did not draw any connection (as EPA attempts to do in its preamble) to carrying out any aspect of the CAA. Nor did the Appropriations Act provide EPA any new authority under the CAA to promulgate a mandatory GHG reporting rule. Therefore, EPA's reliance on Sections 114 and 208 is misplaced because, as explained above, these Sections may only be invoked for specified purposes under the CAA. General information gathering pursuant to the appropriations language is not within the scope of authority conferred by Sections 114 and 208.

Moreover, the narrowly prescribed activity funded by the Appropriations Act necessarily constrains the scope of EPA's information gathering under Sections 114 and 208. First, given the limited funds authorized by Congress, it would be impossible to maintain the indefinite and overly expansive reporting program proposed. Second, the Appropriations Act does not prescribe

[1] As explained further below, a facility must be subject to a statutory or regulatory provision that requires actual control of their emissions before it can be said to be subject to regulation under the Act. Similarly, in this context, an "emission source" must be read to be limited to sources that emit regulated pollutants, which do not include GHGs.

any enforcement authority.[2] Because the CAA does not independently provide the authority for the proposed rule, it cannot be (as EPA proposes) the basis for any enforcement action. *See* 74 Fed. Reg. at 16595 *("Facilities that fail to report GHG emissions according to the requirements of the proposed rule could potentially be subject to enforcement action by EPA under CAA sections 113 and 203–205.")*. Congressional grants of enforcement authority must be explicit. *Cf. Marshall v. Gibson's Products, Inc. of Plano*, 584 F.2d 668, 675 (5th Cir. 1978) ("Congress is cognizant of the need to set forth explicitly the authority of an administrator or agency to seek enforcement relief in federal court."). Third, the Appropriations Act also expressly limited EPA's authority to promulgating a rule to require reporting of "greenhouse gas emissions." The term "emissions" unambiguously means material that is actually discharged into the air. "If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 842-43. Therefore, EPA has no authority to require anything more than emissions to be reported. The proposed rule exceeds this limitation on EPA's authority in many respects; for example, it would require the reporting of fuel production and distribution information, which is not the reporting of emissions.

API cautions EPA against trying to use the proposed reporting rule as a way to anticipate or lay the groundwork for future climate change legislation. EPA states that the "mandatory reporting program would provide comprehensive and accurate data which would inform future climate change policies," 74 Fed. Reg. at 16456, and that it "do[es] not yet know which specific policy options the data may ultimately be used to support," *id.* at 16475. Until EPA clearly identifies the policy options it will pursue with respect to greenhouse gas emissions, EPA should limit the proposed rule to require the collection of reasonably accurate and complete data using readily available sources or estimation methods. It is inappropriate at this time for EPA to require the level of exquisite precision that would be necessary in the context of a compliance-oriented regulatory program. As presently drafted, the proposed rule runs the risk of collecting data that EPA will ultimately not need at considerable costs to affected entities – or failing to collect data that EPA would need to carry out particular programs.

API believes that EPA's reporting efforts – and the resources of regulated entities – would be more productively targeted if EPA were to identify with greater specificity the policies or programs that it intends to develop using the data gathered under the Proposed Rule and limit reporting requirements to support those policies or programs.

API recognizes that the non-binding, explanatory statement to the Appropriations Act directed EPA to consider "upstream production and downstream sources" to the extent EPA "deems it appropriate." 74 Fed. Reg. 16454. API is concerned, however, that in many provisions EPA has cast its net beyond what is necessary to gather adequate and useful data and in many places requests information that results in unnecessary double counting or inaccurate counting (e.g., assuming that all NGLs are burned). API believes that it would be illogical for Congress to direct EPA to count the same unit of GHG at the point of emission *and* further upstream. As such, the explanatory statement is most reasonably interpreted as an instruction to EPA to *consider* upstream and downstream reporting, but choose between these approaches as appropriate in any given sector. If there are compelling policy reasons in specific situations that would justify the

[2] Courts generally construe penal authority very narrowly and require a showing of explicit statutory authority in order to uphold a sanction. Here, the authorizing language of the Appropriations Act does not contain any explicit enforcement language.

collection of both upstream production and downstream sources, those situations and policies need to be clearly identified. The overriding principle, however, should be to minimize double counting in order to avoid inaccurate assessments, unjustified complications and increased costs.

In sum, given the agency's limited authority to promulgate the proposed rule, at a minimum, the duration and enforcement provisions must be amended. In addition, the rule should be directed solely at reporting actual "greenhouse gas emissions" and avoid double counting.

2. Linkage to Clean Air Act provisions

PSD/NSR

API requests that the final rule explain and reaffirm EPA's long standing view that none of the requirements of the monitoring rule (including 40 C.F.R. Part 98 and none of the amendments to 40 C.F.R. Parts 86, 89, 90, 91, 92, 94, 1033, 1039, 1042, 1045, 1048, 1051, and 1054) make CO_2 or any other GHG a "regulated pollutant" under the Clean Air Act ("CAA"). EPA has already stated that by proposing the mandatory GHG reporting rule the Agency has not indicated that it has made any final decision about the potential regulation of GHGs under the CAA. *See* 74 Fed. Reg. at 16456. EPA should affirm in the final rule the well-established position that mere monitoring of a pollutant does not make it "subject to regulation" under the CAA.

It is well established that monitoring and reporting requirements similar to those proposed by EPA would not make GHGs subject to regulation, nor would the reporting requirements themselves constitute regulation of GHG emissions under the CAA (or trigger the permitting of emissions of GHGs under the CAA Prevention of Significant Deterioration ("PSD") program).[3] PSD permit limits are required only for pollutants that are subject to an actual emission control limit under another provision of the CAA. This conclusion is supported by EPA's recent interpretative rule (commonly know as the "Johnson Memorandum"), which set forth "EPA's definitive interpretation" that CO_2 is not currently regulated under the CAA, even though there are currently CO_2 monitoring and reporting provisions under Section 821 of the CAA.[4] EPA interpreted the term "regulated NSR pollutant" in 40 C.F.R. § 52.21(b)(5) to cover "only those pollutants subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant." Johnson Memorandum at 6. As expansive as the proposed monitoring rule, nothing in the proposal would subject GHG emissions to control requirements.

The view that monitoring does not to equate regulation has been consistently asserted by the EPA following *Massachusetts v. EPA*, 549 U.S. 497 (2007). For example, in its recent Advance Notice of Proposed Rulemaking ("ANPR") for addressing GHGs under the CAA, EPA again

[3] Under the PSD program, certain new major sources are required to obtain a pre-construction permit. *See* 42 U.S.C. §§ 7470-7492. A permit issued to a major emitting facility must include the best available control technology ("BACT") to control emissions of "each pollutant subject to regulation under this Act emitted from, or which results from, such facility." CAA § 165(a)(4); 42 U.S.C. § 7475(a)(4). The PSD regulations further specify that BACT limits are required only for "regulated [New Source Review] pollutants." 40 C.F.R. § 52.21(b)(50). The definition of "regulated NSR pollutants" includes "[a]ny pollutant that otherwise is subject to regulation under the Act." *Id.*

[4] *See* Stephen L. Johnson, Administrator, U.S. EPA, EPA's Interpretation of Regulations That Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program (Dec. 18, 2008), at 1, published at 73 Fed. Reg. 80,300 (Dec. 31, 2008) (hereinafter "Johnson Memorandum"). Although EPA has agreed to reconsider the Johnson Memorandum through a notice-and-comment process, the Agency expressly declined to stay its effectiveness. *See* Letter from Lisa P. Jackson, Administrator, EPA (Feb. 17, 2009).

affirmed that CO_2 is not presently "subject to regulation" under the CAA. The ANPR demonstrated that EPA was considering, for the first time, regulation of GHGs under the CAA. EPA, ANPR for Regulating Greenhouse Gas Emissions Under the Clean Air Act (hereinafter "ANPR"), 73 Fed. Reg. 44,354, 44,497–44,510 (July 30, 2008). Despite ongoing monitoring of GHGs pursuant to Section 821, EPA made it clear that GHGs are not regulated pollutants under the CAA. "Since there is no NAAQS for GHGs and GHGs are not otherwise subject to regulation under the CAA, the PSD program is not currently applicable to GHGs." ANPR, 73 Fed. Reg. at 44,497. EPA confirmed that point again when it issued a proposed endangerment finding for GHGs under CAA Section 202. *See* Proposed Rule, Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA, 74 Fed. Reg. 18,886, 18,905 n.29 (proposed Apr. 24, 2009). EPA has consistently reached this conclusion in these and other contexts despite arguments by some groups that the GHG monitoring obligations imposed by Section 821 subject GHGs to regulation under the CAA.

EPA's well-established interpretation is consistent with the law and should be reinforced in the final rule. The phrase "subject to regulation" is best understood to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions. That interpretation aligns with the common meaning of "regulation" as "the act or process of controlling by rule or restriction." Black's Law Dictionary (8th ed. 1999); *see* Johnson Memorandum at 7-8. In addition, the lack of an article such as "a" before the word "regulation" in the phrase "subject to regulation" more naturally suggests the meaning "subject to control," rather than the meaning "subject to a rule" regardless of the content of the rule. *Id.* at 8.

That "subject to regulation" means being presently subject to a control limit is supported by the plain meaning of the word "subject." *See, e.g.*, Random House Webster's Unabridged Dictionary (2d ed. 2001) (defining "subject" as "being under domination, control, or influence (often fol. by *to*)"); American Heritage Dictionary of the English Language (4th ed. 2006) (defining "subject" as "[b]eing in a position or in circumstances that place one under the power or authority of another or others"). The placement of the phrase "subject to regulation" within the CAA provisions and PSD regulations requiring BACT limits strongly suggests that the phrase refers to pollutants that are actually and presently controlled (and thus "regulated"). *See* 42 U.S.C. §§ 7475(4), 7479(3); 40 C.F.R. § 52.21. Otherwise, PSD permitting authorities would have to guess what pollutants could possibly come under regulation and somehow impose BACT limits on them—*before* emission control standards had been developed.

EPA's long standing and consistent interpretive statements and past practice further affirm that monitoring and reporting requirements for GHGs do not make them "subject to regulation." EPA's position dates back to 1978. In the preamble to the 1978 federal PSD regulations, EPA defined "subject to regulation under the [Act]" in CAA §§ 165 and 169 as "any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations" and then clarified that "[t]his then includes" pollutants regulated under a NAAQS review, an NSPS, the National Emissions Standards for Hazardous Air Pollutants, and Title II mobile source emission standards. 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). Each of those enumerated regulations requires actual emission controls, not just monitoring and reporting. Both in 1990 and in 1996—after promulgating the CO_2 monitoring and reporting regulations under Section 821—EPA made clear that only "regulated" pollutants are subject to the PSD program and provided lists of "regulated" pollutants that did not include CO_2. EPA's interpretive memoranda and decisions of the EAB issued after promulgation of the CO_2 monitoring and reporting regulations have also consistently said that CO_2 is not a regulated pollutant. In addition, the 2002 preamble to the rulemaking that established the governing "regulated NSR pollutant" definition listed "pollutants currently regulated under the Act" and "subject to Federal PSD review and permitting requirements." 67 Fed. Reg. 80,186, 80,239-40 (Dec. 31, 2002). That list did not include CO_2. *Id.*

EPA's past practice is consistent with the view that mere monitoring does not trigger regulation. After reviewing a full record of PSD permits issued by EPA and the delegated States, EPA concluded that none contained emissions limitations for pollutants that are subject only to monitoring and reporting requirements. *See* Johnson Memorandum at 11. Indeed, even though EPA has had regulations in place requiring monitoring and reporting of CO_2 emissions since 1993, neither EPA nor any delegated states have issued PSD permits containing limits on CO_2. *Id.* This practice supports the conclusion that only regulations requiring actual control of a pollutant's emissions make that pollutant "subject to regulation" under the CAA.

Similar to the monitoring requirements of Section 821 of the CAA, the proposed rule's requirements are intended to gather information, not to impose a limitation or control on GHG emissions. A determination that GHG emissions controls are warranted simply because EPA is gathering information about GHG emissions would improperly ignore the stated purpose of gathering the information: aiding EPA in determining *if* and *how* GHG emissions should be controlled. As EPA has explained, adopting a definition of "subject to regulation" that includes any pollutant covered by any regulatory provision "would lead to the perverse result of requiring emissions limitations under the PSD program while the Agency is still gathering the information necessary to conduct research or evaluate whether to establish controls on the pollutant under other parts of the Act." Johnson Memorandum at 9. It would be improper to allow the proposed monitoring and reporting requirements, which allow EPA to gather information to help inform its judgment regarding the need to establish controls for GHGs, to automatically trigger such controls. *Cf. id.* at 9-10 (if by collecting and reporting emissions data for CO_2, a permitting agency was required to include CO_2 emission limitations based on BACT, "the mere act of gathering information would [have] essentially dictate[d] the result of the decision that the information is being gathered to inform (whether or not to require control of a pollutant.")).

Therefore, because the proposed GHG monitoring and reporting requirements do not mandate any emission control requirements, EPA should make clear that they do not make GHGs subject to regulation under the CAA and do not trigger CAA permitting requirements.

Title V

API respectfully requests that the final rulemaking expressly state that the applicability of the monitoring rule to a particular facility will not automatically trigger any other Clean Air Act obligations for that facility. Specifically, the rule should state that it does not establish any "applicable requirements" that must be contained in Title V operating permits. *See* 40 C.F.R. § 70.3(c). Under 40 C.F.R. § 70.2, an "applicable requirement" is limited to a particular set of standards, conditions, and other requirements (set forth in that regulation) that apply pursuant to a specific provision of the CAA or applicable State Implementation Plan. Notably, while the regulatory definition includes "[a]ny requirements established pursuant to section 504(b) or section 114(a)(3) of the Act," it does *not* include requirements established pursuant to Section 114(a)(1) or Section 208, which EPA asserts as its statutory authority for the proposed rule. *See* 74 Fed. Reg. at 16454-55. Therefore, we request EPA clarify that the proposed rule does not trigger any Title V obligations nor establish requirements that must be incorporated into Title V permits.

3. Treatment of Confidential Business Information

The proposed rule requires the reporting of information that, if disclosed, would divulge methods and processes entitled to protection as trade secrets and confidential business information ("CBI"). The fuel production and distribution information requested of suppliers of fossil fuels in Subparts MM, NN, and PP of the proposed rule, and the operational information requested of petroleum refineries in proposed Subpart Y, is entitled to confidential treatment. As explained below, this information qualifies for protection under EPA's regulations governing the confidentiality of business information. *See* 40 C.F.R. §§ 2.208, 2.301(e). EPA's plan to evaluate requests for CBI protection on a case-by-case basis is inefficient and likely unworkable given the large volume of CBI that would be collected under the proposed rule.

Instead, in its final rulemaking, API urges EPA to make "class determinations" pursuant to 40 C.F.R. § 2.207 that **(1)** the information requested of suppliers in proposed Subparts MM, NN, and PP (collectively, "Fuels Production and Distribution Data") and **(2)** the operational information requested of petroleum refineries in proposed Subpart Y (collectively, "Operational Data"), satisfy all of the substantive criteria for receiving confidential treatment (*see* 40 C.F.R. §§ 2.208, 2.301(e)).

Business information is entitled to confidential treatment if:

(a) "[t]he business has asserted a business confidentiality claim which has not expired by its terms, nor been waived nor withdrawn";

(b) "[t]he business has satisfactorily shown that it has taken reasonable measures to protect the confidentiality of the information, and that it intends to continue to take such measures;

(c) "[t]he information is not, and has not been, reasonably obtainable without the business's consent;"

(d) "[n]o statute specifically requires disclosure of the information; and

(e) either the business shows that disclosure of the information "is likely to cause substantial harm to the business's competitive position" or, if the information is voluntarily submitted, "its disclosure would be likely to impair the Government's ability to obtain necessary information in the future."

40 C.F.R. § 2.208. These substantive criteria apply to information collected pursuant to Sections 114 and 208 of the CAA, except that information which is "emission data, a standard or limitation, or is collected pursuant to Section 211(b)(2)(A) of the Act is not eligible for confidential treatment." 40 C.F.R. § 2.301(e). Here, "class determinations" are warranted because, for both categories of information, the five prerequisites are satisfied. Moreover, the requested data is not "emissions data" and therefore is not exempt from confidential treatment.

A. Fuels Production and Distribution Data

1. API members are asserting business confidentiality claims

With these comments, API members are properly asserting their business confidentiality claim with respect to the information requested in proposed Subparts MM, NN, and PP. *Id.* at

2.208(a). This fuels production and distribution data is extremely sensitive and is already regularly collected by other government agencies as CBI. Moreover, as described below, this information is not emissions data, as it has nothing to do with actual emissions from the entities that are supplying the information. Rather, the information is a surrogate for measuring potential emissions from the sources that eventually use the fuel.

2. <u>API members have taken and will continue take reasonable measures to protect the confidentiality of the requested data</u>

API and its members have historically protected fuel production and distribution information and have taken reasonable measures to ensure its continued protection. *Id.* at 2.208(b). For example, the Department of Energy ("DOE") protects the confidentiality of similar fuels and products marketing and distribution data provided by the industry. The DOE Energy Information Administration ("EIA") has extensive databases on fuel consumption and use by industry, and EIA surveys provide state-level production and regional-level information on fuel imports. However, EIA appropriately provides confidential treatment for facility-level fuel production and distribution information. *See* Exhibit 1 (EIA Confidentiality Disclaimer). Indeed, EIA is prohibited from making public or sharing disaggregated or entity-specific fuel use or distribution data. *See* 44 U.S.C. § 3501 note at Sec. 208 (preventing disclosure of information in identifiable form where information was submitted under a pledge of confidentiality).

3. <u>The information is neither reasonably obtainable without API member consent nor is it required by statute</u>

EPA could not otherwise obtain the fuel production and distribution data without the consent of the relevant businesses. *Id.* at 2.208(c). Further, the cost or difficulty associated with obtaining information is an important consideration in assessing whether it is "reasonably obtainable." *Worthington Compressors, Inc. v. Costle,* 662 F.2d 45, 52 (D.C. Cir. 1981). This information could not be easily collected without the businesses' consent. In addition, "[n]o statute *specifically requires* disclosure of the information" about fuel use and distribution to EPA. *Id.* at 2.208(d) (emphasis added). EPA has never asserted that the requested information is required by statute. Instead, the agency cites the general provisions of Sections 114 and 208 as its authority for requesting the information; even assuming that these statutory provisions are applicable here, they provide only *discretionary* authority to require recordkeeping, monitoring, and reporting, *e.g.* 42 U.S.C. § 7414(a)(1) ("the Administrator *may* require . . . .") (emphasis added).

4. <u>Disclosure of the information is likely to cause substantial harm to the API members' competitive positions</u>

Above all, public disclosure of the fuel production and distribution data in a manner that would link such data to particular entities would substantially harm the competitive position of API members. *Id.* at 2.208(e). EPA plans to publish data collected under this rulemaking through its website, reports, and other formats. If the requested information was disclosed, it would likely result in substantial harmful effects to the businesses' competitive positions. The facility-by-facility information requested of suppliers, importers and exporters of fuels goes to the heart of the ability of these businesses to compete in the marketplace. For example, disclosure of fuel volumes could be harmful to a company because its competitors might use the information to help formulate a strategy for taking business from that company. Specifically, if company A were to know how much business companies B and C were doing at a specific terminal, company A could look at how sales for each of the other companies varied over time, could analyze factors such as actual prices at the terminal, prices at retail outlets downstream from the terminal, company A promotional or allowance activities and those of competitors to the extent known, and likely determine the best means of taking business from companies B and C. Disclosure of the requested fuels information would also allow competitors to determine the company's market share and assess the potential volume available to be acquired.

Similarly, public disclosure would harm API members' competitive position in the marketplace by eroding the proprietary value of manufacturer, supplier, distributor or purchaser's contractual relationships and ongoing business activity. If information collected under the proposed Subparts MM, NN, and PP were publicly disclosed, the essential terms of these contracts could be discerned and potentially exploited by competitors, who would be able to identify product mix, quantities, and entities.

Finally, although EPA did not include reporting of geologic sequestration in the proposed rulemaking, EPA "outlined initial thoughts about how geologic sequestration might be included in a reporting program for enhanced oil recovery sequestration." 74 Fed. Reg. at 16584. Disclosure of such information could also harm a business' position in the marketplace. Therefore, if such information were ever collected, it would be entitled to CBI protection.

Because public disclosure of the fuel production and distribution would substantially harm market competition, API urges EPA to ensure the protection of this highly sensitive data.

5. <u>The requested information is not "air emissions data" exempt from confidential treatment</u>

Finally, fuel production and distribution information is not "emission data," and therefore is eligible for confidential treatment under EPA regulations.[5] "Emission data" is only

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[5] Under 40 C.F.R. § 2.301(e), "information which is emission data" is not eligible for confidential treatment. The requested information, however, is not emission data. EPA has defined emission data as:

> (A) Information *necessary to determine* the identity, amount, frequency, concentration, or other characteristics . . . of any emission which has been emitted by the source . . .;
>
> (B) Information *necessary to determine* the identity, amount, frequency, concentration, or other characteristics . . . of the emissions which . . . the source was authorized to emit . . .; and
>
> (C) A general description of the location and/or nature of the source to the extent *necessary to identify* the source and distinguish it from other sources . . . .

40 C.F.R. § 2.301(a)(2)(i) (emphasis added). In addition, certain information:

> shall be considered to be emission data only to the extent necessary to allow EPA to disclose publicly that a source is (or is not) in compliance with an applicable standard or limitation, or to allow EPA to demonstrate the feasibility, practicability, or attainability (or lack thereof) of an existing or proposed standard or limitation:
>
> (A) Information concerning research, or the results of research, on any project, method, device or installation (or any component thereof) which was produced, developed, installed, and used only for research purposes; and
>
> (B) Information concerning any product, method, device, or installation (or any component thereof) designed and intended to be marketed or used commercially but not yet so marketed or used.

40 C.F.R. § 2.301(a)(2)(ii).

information *necessary* to determine characteristics related to *past actual* emissions from the emission *source* itself. *See, e.g.,* 40 C.F.R. § 2.301(a)(2)(i) (defining emission data, in part, as "Information *necessary* to determine the identity, amount, frequency, concentration, or other characteristics . . . of any emission *which has been emitted by the source* . . ."). In contrast, the requested information bears no relationship to past actual emissions from any of the sources providing such data. Even if EPA were to impermissibly interpret the monitoring rule as indirectly encompassing emissions from downstream sources that combust fuels, such an interpretation still would not satisfy the regulation's narrow and limited "emissions data" exemption to established CBI.

EPA's proposed rule theoretically purports to require the reporting of emissions that *might* occur in the future *if* the products the suppliers place in commerce are completely combusted or oxidized downstream by countless users outside the control of those required to report fuel production and distribution data. For example, under proposed 40 C.F.R. § 98.32, suppliers of petroleum products must report "the CO_2 emissions that *would result* from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year. Additionally, refiners must report CO_2 emissions that *would result* from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks." (emphasis added). Suppliers of natural gas and natural gas liquids also must report information that is plainly not emissions data. The rule requires natural gas processing plants to report the CO_2 emissions that *would* result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, isobutene and bulk natural gas liquids *sold or delivered for use off site*. *See* proposed 40 C.F.R. § 98.402(a). "Local distribution companies must report the CO_2 emissions that *would* result from the complete combustion or oxidation of the annual volumes of natural gas *provided to end-users*." Id. at § 98.402(b) (emphasis added). The requested information is not "emission data" because the term "emission" unambiguously means material that is actually discharged into the air. As such, information related to prospective, hypothetical emissions from countless sources independent of those producing the data by no means meets the regulatory definition of "emission data" and, therefore, that information is still eligible for CBI protection.

Notably, EPA itself has successfully argued that the public disclosure of "emissions data" focuses on emissions that have been "emitted by the source" or that "the source was authorized to emit" rather than potential future emissions by other sources outside the control of the party producing the information. *NRDC v. Leavitt*, Civ. No. 04-01295, 2006 WL 667327, at *3 (D.D.C. March 14, 2006) (citing 40 C.F.R. § 2.301(a)(2)(i)(A) & (B)). In that case, NRDC sought release of information about certain manufacturers' stockpiles of the pesticide methyl bromide. NRDC argued that "because future emissions of methyl bromide are 'directly related' to the size of current methyl bromide stockpiles," the information was "emissions data." *Id.* EPA responded that the connection between information about specific company's stockpiles "is too attenuated to actual [future] emissions" of methyl bromide to fall within the ambit of the EPA definition of "emissions data." The court agreed with EPA, holding that a "plain reading of 40 C.F.R. § 2.301(a)(2)(i) indicates that 'emissions data' is defined narrowly to focus on information obtained from a source of emissions, not a producer of materials that will later contribute to emissions." *Id.* at *4. The court's conclusion, and EPA's reasoning, in that case supports the conclusion that fuel production and distribution data is information about "producers of materials that will later contribute to emissions" and thus is not "emissions data."

Fuel production data, which EPA is using to generate hypothetical emissions from mobile and other sources, is also not data about emissions "by the source" from which it is being collected, as defined by EPA regulation. *See, e.g.*, 40 C.F.R. § 2.301(a)(2)(i) (referring to information needed to identify characteristics of any emission "which has been emitted *by the source*."). Here, EPA plans to use the fuel production data, to which emission factors will be applied, as a surrogate for measuring the potential future emissions from a variety of different and unknown sources. Fuel production data is not data about emissions from the suppliers from which the data is being collected. In the *NRDC* case, the court noted that "the five methyl bromide manufacturers are not directly responsible for any emissions; instead, it is the purchasers of methyl bromide that will create any eventual emissions." 2006 WL 667327, at *3. As noted above, information about the manufacturers' stockpiles was held not to be emissions data. *Id.* at *4. Similarly, the suppliers covered by the proposed rule are not actually combusting or oxidizing the relevant products and therefore information about their fuel production and distribution is not "emissions data." This information should therefore be treated confidentially.

Finally, the information does not qualify as emission data because it is not "necessary to determine" the characteristics of any emissions. *See* 40 C.F.R. § 2.301(a)(2)(i). Importantly, before concluding that the requested information is "necessary" to determine emissions or source, EPA must consider all relevant factors, "including available alternatives, so that release of information claimed to be proprietary could be avoided unless required by statute." *RSR Corp. v. EPA*, 588 F. Supp. 1251, 1256 (D.C. Tex. 1984) (remanding to EPA to determine if information was "necessary to determine" emissions). A "strict interpretation of the 'necessary to determine' requirement is warranted in order to ensure that the exception does not swallow the rule." *NRDC*, 2006 WL 667327, at *4. Much of the requested data is not necessary to determine the characteristics any emissions. For example, the country of origin of crude oil provides no concrete information about any actual emissions. At bottom, none of the fuels information is "emissions data" because it provides no information about any actual "emissions." As explained above, the plain unambiguous meaning of the term "emissions" is material that is actually discharged into the air. For these reasons, the fuel production and distribution data warrants confidential treatment and should be protected as such under any final rulemaking.

B. Operational Data

Certain of the information associated with measuring emissions from the refineries themselves is also entitled to CBI protection. Subpart Y of the proposed rule requires process-specific information and production volumes be reported as well as information on equipment leaks, storage tanks, uncontrolled blowdown systems, delayed coking units, and loading operations. These detailed data should be provided confidential treatment because they meet the substantive criteria outlined above. With these comments, API members are properly asserting their business confidentiality claim. *See* 40 C.F.R. 2.208(a). API members protect the requested information as confidential and, without their consent; EPA could not otherwise easily obtain the information. *See id.* at § 2.208(b)-(c). In addition, no statute specifically requires disclosure of the information. *See id.* at § 2.208(d). The data is also definitely not "emissions data" and thus is still eligible for confidential treatment.

Most importantly, disclosure of the requested operational data would substantially harm the competitive position of the Associations' members. *See id.* at § 2.208(e). The disclosure of process-specific information and production volumes would reveal sensitive process capabilities and operational limits. In addition, if that information were combined with other publicly available information, disclosed under air quality permits and CAA Section 112(r) hazard assessments, competitors would have a detailed picture of a facility's operational capabilities. This information could expose a facility's business position, weaknesses, or vulnerabilities, which could then be used by competitors to disadvantage the reporting facility. For example, the disclosure of unit-specific throughputs and unit-specific fuel use could give competitors a detailed understanding of a facility's process capability and create an advantage in optimizing future crude or product supply. Disclosure of fuel use and process volumes would also reveal a refinery's process operational capacity, limits, bottlenecks, and options to reconfigure in response to market change. This information would indicate a facility's ability (or inability) to capitalize on specific market opportunities and allow competitors to target markets based on the facility's weakness or vulnerabilities. Finally, the disclosure of operational data and throughputs would enable equipment/technology providers to quantify the facility's capabilities. This information could be used against the refiner in future negotiations to upgrade or replace their equipment. For these reasons, the operational data requested of petroleum refineries should receive confidential treatment.

To the extent that EPA may believe that the requested information could be determined to fit within the existing regulatory definition of "emission data," the existing regulation exceeds EPA's statutory authority by a establishing an unreasonably broad definition of "emission data." As has been described above, API members have historically taken reasonable measures to protect the requested information, disclosure of this information is not required by statute and cannot otherwise be reasonably obtained without the relevant businesses' consent, and, most importantly, disclosure of the requested information would result in substantial harm to API members' competitive positions. For these reasons, EPA should issue class determinations protecting the above-specified information.

4. "Designated Representative"

Under the proposed rule, a designated representative (or a properly designated alternate) would be required to complete a certification of the GHG emissions report. API recommends that the requirements and responsibilities of the designated representative be amended, as set forth in the following Redline of Proposed Section 98.4 (see Exhibit 4 below). Our proposed modifications are based on EPA certifications required in other established environmental programs such as the Toxics Release Inventory ("TRI") program. We believe certification provisions in such programs provide a better template for certification for the GHG reporting rule. Below, we explain four of our primary concerns with the proposed rule's language.

First, the proposed certification statement that requires the designated representative has "personally examined" the submitted information sets an inappropriate standard for a plant manager, or his/her "designated representative." An appropriately high-level management official at a complex facility is unlikely in a position to *"personally examine"* all the underlying documents used to prepare the emissions report. This could in essence be an all-encompassing full-time job that would distract unduly from other management responsibilities. A more appropriate standard is one that is similar to the TRI program, which requires the designated representative to certify based on the best of his or her knowledge and belief.

Second, EPA should not include requirements that dictate how the designated representative be selected. The proposed rule would intrude upon the existing legal arrangements between owners and operators by requiring the designated representative "be selected by an agreement binding on the owners and operators . . . ." API recommends deletion of this requirement.

Third, the proposed provisions for the "alternate designated representative" sets an inappropriate level of liability on the original "designated representative," particularly when the designated representative has delegated responsibility. The proposed rule allows for the designated representative to delegate responsibility to an alternative designate representative. For example, the designated representative might be on vacation or a medical leave. However, the rule language in Section 98.4(f)(1) states that ". . . . .any representation, action, inaction, or submission by the alternate designate representative shall be deemed to be a representation, action, inaction or submission by the designated representative." API recommends that Section 98.4(f)(1) be deleted--- the responsibility should lie with the alternate designate representative in these circumstances.

Fourth, API believes the requirements related to the "certificate of representation" are unwieldy and unnecessary. We request that EPA eliminate the entirety of subsection (i) of Section 98.4 and all related references to the certificate, such as subsections (d) and (k). Apart from the Acid Rain Program, which – as explained further below – is fundamentally different than the proposed reporting program, EPA has historically not required such a certificate in other programs. The TRI program, which is the program most analogous to the proposed reporting rule, does not require such a certificate. Requiring entities subject to this rule to complete such certificates would be a cumbersome process.

For example, the requirement in proposed Section 98.4(g)(3) that a "list of the owners and operators of the facility or supply operation" be included in the certificate would require substantial paperwork for some entities as there are often frequent changes in ownership and operators. Moreover, many facilities have long lists of owners with small interests or royalty interests, for example, such that compliance with the proposed requirement will create a paperwork nightmare. The burden of complying with these provisions is amplified when they are coupled with the requirement in proposed Section 98.4(h) that facilities submit updated certificates every time there is a change in owners or operators. Given that EPA's stated primary purpose behind the proposed rule is data collection, such detailed and frequently updated lists of owners and operators are unnecessary.

Notably, even if EPA decides to keep the proposed rule's requirement for a certificate of representation, API recommends that Sections 98.4(g)(3) and 98.4(h) still be deleted for the reasons stated above.[6] These requirements would result in great burden and would not serve the purposes of the stated rule. In addition, should EPA retain the certificate of representation requirement, it should still eliminate the requirement that the certificate be revised if the designated representative changes. Considering the frequency of personnel changes, having facilities send in updated certificates of representation provides no value and creates an unnecessary paperwork exercise. API also recommends that, if the certificate of representation requirement is retained in the final rule, EPA allow it to be completed in a more general format, such as by the "plant manager or their delegated representative." Other EPA-administered permit programs, such as the Hazardous Waste Permit Program, allow for assignment or delegation of the designated representative duties to applicable corporate positions rather than to specific individuals. *See* 40 C.F.R. § 270.11(a).

API acknowledges that the provisions in the proposed rule are patterned after EPA's Acid Rain Program regulations regarding the authorization and responsibility of the designated representative in that program. *See* 40 C.F.R. §§ 72.20 – 72.26. API recommends against using the Acid Rain Program regulations as a model for the current proposed regulations. In the Acid Rain Program, the designated representative's certificate of representation and related requirements are completed in the context of a program where emission allowances are being bought and sold. The mandatory reporting rule is proposed in an entirely different context and for the purpose of information gathering. In addition, unlike the Acid Rain Program, which is designed to monitor emission from a single source category (utilities), the proposed GHG reporting rule applies to scores if not hundreds of different categories—from landfills and wastewater treatment to oil refiners and chemical manufacturers—that are fundamentally distinct and disparate in their nature. The increased complexity of the proposed GHG reporting rule warrants significantly greater flexibility than the Acid Rain Program, as demonstrated by the length of the GHG reporting rule itself. Further, many of these almost infinite entities have complex ownership patterns that would make certain aspects of the proposed certification process problematic. EPA should look to other established environmental programs that similarly account for a multitude of different industries, such as TRI, as the better model for this rule.

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[6] The implication in the proposed 40 C.F.R. § 98.4(h) that a new owner of a facility could incur legal liability for actions that the Designated Representative undertook under previous ownership is very concerning. If EPA decides to retain subsection (h), it should at least clarify that, in accordance with accepted tenets of agency and contract law, a new owner's liability only extends to actions of the Designated Representative made after the change in ownership and after the point when the Designated Representative becomes an employee of the new owner. In an industry where facilities frequently change corporate ownership, lack of clarity on this point could unintentionally create significant legal risks.

API proposes the following language be substituted for the proposed § 98.4(h):

> 40 CFR § 98.4(h)(1) Changes in owners and operators. In the event a new owner or operator is not included in the list of owners and operators in the certificate of representation under this section, such new owner or operator shall be deemed to be subject to and bound by statements or actions of the designated representative made after the new owner or operator commenced ownership or operation.
> (2) Liability. Notwithstanding any other provision of this subpart, no new owner or operator of a facility shall be held liable for any certificate, representation, action, inaction or submission of a designated representative made before the new owner obtained title to the reporting facility or the new operator executed an operating agreement for the reporting facility.

Exhibit 4 - Redline of § 98.4 Authorization and responsibilities of the designated representative for a facility or supply operation

(a) *General*. Except as provided under paragraph (d) of this section, each owner or operator of a facility or supply operation that is subject to this part, shall have one and only one designated representative responsible for certifying and submitting GHG emissions reports and any other submissions to the Administrator under this part.

(b) *Authorization of a designated representative.* ~~The designated representative of the facility shall be selected by an agreement binding on the owners and operators and shall act in accordance with the certification statements in paragraph (i)(4) of this section.~~ The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the facility or supply operation.

~~(c) *Responsibility of the designated representative.* Upon receipt by the Administrator of a complete certificate of representation under this section, the designated representative of the facility shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.~~

~~(d) *Timing.* No GHG emissions report or other submissions under this part will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the owner or operator.~~

(c) *Certification of the GHG emissions report.* Each GHG emission report and any other submission under this part shall be submitted, signed, and certified by the designated representative in accordance with 40 CFR 3.10.

(1) Each such submission shall include the following certification statement by the designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate) for which the submission is made. I certify under penalty of law that I have ~~personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''~~reviewed the attached document and, to the best of my knowledge and belief, the submitted information is true, accurate, and complete.'' (2) The Administrator will accept a GHG emission report or other submission under this part only if the submission is signed and certified in accordance with paragraph ~~(e)~~(c)(1) of this section.

(d) *Alternate designated representative.* A certificate of representation under this section may designate an alternate designated representative, who may act on behalf of the designated representative. ~~The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.~~

(e) *Changing a designated representative or alternate designated representative.* The designated representative (or alternate designated representative) may be changed at any time~~ upon receipt by the Administrator of a superseding complete certificate of representation under this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative (or alternate designated representative) before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators~~.

~~(1) Upon receipt by the Administrator of a complete certificate of representation under this section, any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.~~

~~(2) Except in this section, whenever the term ''designated representative'' is used, the term shall be construed to include the designated representative or any alternate designated representative.~~

~~(g) *Changing a designated representative or alternate designated representative.* The designated representative (or alternate designated representative) may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative (or alternate designated representative) before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.~~

~~(h) *Changes in owners and operators.* In the event a new owner or operator is not included in the list of owners and operators in the certificate of representation under this section, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative, as if the new owner or operator were included in such list. Within 30 days following any change in the owners and operators, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under this section amending the list of owners and operators to include the change.~~

~~(i) *Certificate of representation.* A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:~~

~~(1) Identification of the facility or supply operation for which the certificate of representation is submitted.~~

~~(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.~~

~~(3) A list of the owners and operators of the facility or supply operation.~~

~~(4) The following certification statements by the designated representative and any alternate designated representative:~~

~~(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators that are subject to the requirements of 40 CFR 98.3.''~~

~~(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the Mandatory Greenhouse Gas Reporting Program on behalf of the owners and operators that are subject to the requirements of 40 CFR 98.3 and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''~~

~~(iii) ''I certify that the owners and operators that are subject to the requirements of 40 CFR 98.3 shall be bound by any order issued to me by the Administrator or a court regarding the source or unit.''~~
~~(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a facility (or supply operation as appropriate) that is subject to the requirements of 40 CFR 98.3, I certify that I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator that is subject to the requirements of 40 CFR 98.3.''~~
~~(5) The signature of the designated representative and any alternate designated representative and the dates signed.~~
~~(j) *Documents of Agreement.* Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.~~
~~(k) *Binding nature of the certificate of representation.* Once a complete certificate of representation under this section has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under this section is received by the Administrator.~~
~~(l) *Objections concerning a designated representative.* (1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under the Mandatory Greenhouse Gas Reporting Program.~~
~~(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.~~

End of Edited Section

V. SPECIFIC COMMENTS KEYED TO THE MRR SUBPARTS

Preamble – Responses to EPA Requests

a. EPA Requested Feedback

1. *"EPA solicits comment on whether the submission of the Inventory to the UNFCCC could be utilized to satisfy the requirements of the rule promulgated by EPA pursuant to the FY2008 Consolidated Appropriations Act." (p. 16455)*
API comments: API believes that EPA should use all existing reported data to fulfill Congress's requirements and only require supplemental data reporting where such existing data are insufficient for informing policy development. API does not hold the requisite information to comment directly on the sufficiency of the National GHG Inventory.

2. EPA seeks comment, *"on whether [reporting the quantity of electricity generated onsite] would be useful to support future climate policy development, given the other data related to GHG emissions from electricity generation already collected under other sections of this proposed rule."* In specific, EPA seeks comment on *"the value of collecting this data; and if it is collected, whether there is a need to separately report the kilowatt-hours by type of generation source." (p. 16473)*
API comments: API supports EPA's decision not to require reporting of electricity generated onsite or electricity generation by fuel type. API sees very little value in this information and the burdens of tracking and reporting are certainly significant.

3. *"EPA is proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. We request comment on whether or not a permit should be required for these emergency generators." (p. 16480)*
API Comments: API supports EPA's approach of not requiring emissions reporting from emergency equipment or portable equipment. The scope of this exclusion should be broadened to include all emergency equipment (not just generators) such as fire-water pumps, life boats, etc.

API does not believe that designation as an emergency unit in a permit should be necessary to exclude emergency equipment from reporting. Some emergency equipment may not be designated as "emergency" in their air permit even though they are for emergency use. Further, some may not be permitted at all. How the emissions from these emergency units are authorized will vary from state to state and jurisdiction to jurisdiction, depending on the details of the programs. For example, due to the MMS jurisdiction in Federal waters there is no permit program and no opportunity to establish a permit designation; Indiana does not permit emergency generators at all, but rather considers them to be de minimis; Texas might cover them under a PBR (Permit by Rule).

EPA should allow additional alternatives for omitting reporting for an emergency unit other than description in an air permit, such as type of use. The emissions from emergency units are very small compared to other stationary fuel combustion sources, and are insignificant compared to the inventory of greenhouse gases; therefore, discounting these emissions will not have a significant impact on the usefulness of the greenhouse gas inventory.

Also in §98.30(b), the term "emergency generators" should be changed to "emergency generators, pumps, lifeboats, and other emergency equipment." Many facilities use combustion units (e.g., diesel engines) as the motive force for emergency pumps, to ensure fire water availability and process fluid movement during power outages and life boats are powered with liquid fuels.

API further recommends that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (§63.6675). These are sources whose operation is limited to emergency situations and whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example.

EPA should exclude infrequent use units (such as small stationary engines) in the same manner in which they have excluded portable equipment which are used during maintenance activities for control and minor power uses.

EPA should specifically acknowledge that portable onshore drilling and completion rigs and mobile offshore drilling units (vessels) are "portable sources", regardless of time at the same lease block or coordinates, and excluded for rule applicability.

4. (Preamble p. 16529) The preamble states "*For this rulemaking, fugitive emissions from the petroleum and natural gas industry are defined as unintentional equipment emissions and intentional or designed releases of CH_4-and/or CO_2-containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. In the context of this rule, fugitive emissions also mean CO_2 emissions resulting from combustion of natural gas in flares. These emissions are hereafter collectively referred to as "fugitive emissions" or "emissions". We seek comment on the proposed definition of fugitives, which is derived from the definition of fugitive emissions outlined in the 2006 IPCC Guidelines for National GHG Inventories, and is often used in the development of GHG inventories. We acknowledge that there are multiple definitions for fugitives, for example, defining the term fugitives to include "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening". According to the 2008 U.S. Inventory, total fugitive emissions of CH_4 and CO_2 from the natural gas and petroleum industry were 160 metric tons CO_2e in 2006. The breakdown of these fugitive emissions is shown in Table W–1 of this preamble.*

API Comments: The proposed rule's definition of fugitives is confusing and inconsistent with industry guidance such as the API Compendium, as well as existing federal rules such as 40 CFR 52.21(i)(20) and 40 CFR 63.2, which state *"Fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening."* EPA's broad use of "fugitive emissions" results in the application of emission methodologies that are not appropriate for vented and/or flared emission sources. API requests that EPA revert to the classical definition of fugitive in conformance with other CAA programs and then list (already mostly done) the individual process, blowdown, and flare sources that are also included within the scope of Subpart W. API also requests EPA address process and vented emissions using estimation methods and factors appropriate to these source types and characteristics, as documented in Section 5 of the API Compendium. In addition, flares should not be considered a fugitive emission source, and should instead be addressed as a combustion emission source. EPA seems prone to this same confusion within the rule itself as evidenced by 98.232 (a) where individual process and flare type sources (acid gas vents, dehydrator vent stacks, flare stacks, etc.) are listed along with broad categories such as "Processing facility fugitive emissions."

The fugitive emissions definition should not result in an expansion of the current CAA regulatory definition of fugitive emissions by including the phrase "unintentional" emissions.

Subpart A – General Provisions Comments

5. §98.3(b) requires reporters to submit annual GHG emission reports no later than March 31 of each calendar year for GHG emissions in the previous calendar year. API requests that emissions reports be submitted no earlier than June 30 of each calendar year for the previous year. For emission data that rely on production data, companies do not have finalized production numbers until at least 45 days after the end of each month. For example, December data would not be available until February 15. Due to the volume of information requested, and the fact that key inputs to the calculations are not immediately available after the end of the year, submission of QA/QC'd and certified reports prior to June 30 is not reasonable.

6. §98.3(g)(7) requires reporters to retain a record of the names and documentation of key facility personnel involved in calculating and reporting the GHG emissions. This requirement is excessive given the requirement for reporters to certify each report. This requirement is also inconsistent with other programs that require reports to be certified but do not require reporters to retain documentation of personnel involved in gathering data, performing calculations, and preparing reports.

7. Under §98.3(g)(9), reporters are required to maintain a log book documenting procedural changes to the GHG emissions accounting methods and changes to the instrumentation critical to GHG emissions calculations. Documenting the information in a log book is redundant. Under §98.3(g)(2), (3), (4) and (6), the reporter is required to document the results of all quality assurance tests for continuous monitoring systems and flow meters, the process used to collect the necessary data for the GHG emissions calculations, the GHG emissions calculations, the methods used, and the operating data and process data used for the GHG emissions calculations. The documentation under §98.3(g)(2), (3), (4) and (6) will show if there was a change to the emissions accounting methods and the instrumentation used to calculate emissions.

8. §98.3(g)(11) requires reporters to maintain a written quality assurance performance plan (QAPP) and information collected under the QAPP. At a minimum, the QAPP must include (or refer to separate documents that contain) a detailed description of the procedures that are used for the maintenance, repair, and calibrations and other quality assurance tests performed on the continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHG emissions report.

This requirement is duplicative for CEMS because the rules that trigger their installation already mandate a quality assurance plan. For other continuous monitoring systems, compliance with standard industry practices will assure sufficient maintenance and repair. Also, "detailed descriptions of the procedures" implies that all possible failure modes can be foreseen, which is not realistic. Sometimes repair procedures are ad hoc because the incident could not be anticipated and the repair is based on trouble shooting results and mechanic knowledge of the equipment.

Requiring a separate QAPP for "all" instrumentation used to provide data for the GHG emissions report is excessive; duplicative with equipment manufacture instructions and standards (such as API, ANSI) which address measurement, instrument calibration, and maintenance; and unnecessarily burdensome.

9. §98.3(g)(11)(ii) In the proposed rule, flow meters would have to be calibrated by January 1st 2010. This requirement is technically impossible to meet due to the number of flow meters at facilities, coupled with the projected finalization of the reporting rule in November of 2009. Also, some instrumentation may require maintenance that prevents verification and/or calibration, where such maintenance cannot be conducted until a shutdown. API does not believe EPA would or should require a shutdown of a facility to calibrate or verify these instruments.

For meters and instrumentation which cannot be calibrated or verified without a facility or unit shutdown, API requests an exemption from a calibration compliance date and a provision for them to be calibrated or verified on a schedule consistent with good industry practice.

10. §98.5 In section III.D (page 16463), EPA states that the "reports would be submitted electronically, in a format to be specified by the Administrator after publication of the final rule. To the extent practicable, [EPA] plan[s] to adapt existing facility reporting program to accept GHG emissions data. [EPA is] developing a new electronic data reporting system for source categories or suppliers for which it is not feasible to use existing reporting mechanisms." EPA further states in section VI.A (page 16593) the "new system would follow Agency standards for design, security, data element and reporting format conformance, and accessibility" and "EPA intends to develop a reporting scheme that minimizes the burden of stakeholders by integrating the new reporting requirements with existing data collection and data management systems, when feasible." EPA acknowledges there are many facets of the reporting scheme, none of which are described in detail in the proposal.

Commenter's cannot evaluate the reporting scheme without the details and cannot comment on concerns, such as ability to use the electronic system, resources needed to implement the system, and cost associated with the reporting scheme. Thus, EPA must propose the reporting scheme for public comment prior to finalizing it.

API Comments on Definitions

Acid Gas §98.6 (p. 16616): API requests replacing the EPA definition with the following: "The hydrogen sulfide and/or carbon dioxide contained in or extracted from gas or other streams" (from GPSA). Including the process in the definition is not appropriate.

Air injected flare §98.6 (p. 16616): Request the following changes to this definition: "A flare in which air is blown into the base of a flare stack to induce complete combustion." Remove, "of low Btu natural gas (i.e. high noncombustible component content.)" It is unnecessary to include the Btu content of the gas stream being burned in the flare. At times high Btu gas could be burned in an air injected flare to provide enough oxygen to promote complete combustion.

Anaerobic digester §98.6 (p. 16616): As stated, this definition could require other parts of a wastewater treatment plant to be brought into the rule. API suggests the following alternative definition for wastewater treatment: "The equipment designed and operated for waste stabilization by the microbial reduction (using acid forming and CH_4 forming bacteria, in the absence of oxygen) of complex organic compounds to CO_2 and CH_4, which is captured and flared or used as a fuel."

Blowdown §98.6 (p. 16617): The EPA definition does not recognize that the stream may contain more than just natural gas. API requests that the following definition from the GPSA be used instead: "The act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower."

Blowdown vent stack fugitive emissions §98.6 (p. 16617): Blowdown vent stack fugitive emissions is defined as natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown, and emergency shut-down system testing. Blowdown stack emissions are not "fugitive" emissions as understood by industry or conventionally defined under state or EPA mandated programs. For example, under Texas' air permit program per 30 TAC 101.1 Definitions, fugitive emissions means any gaseous or particulate contaminant entering the atmosphere that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening designed to direct or control the flow. The departure from conventional definitions that have been used by the EPA and state agencies for decades will cause confusion in the regulated community and could result in inaccurate and incomplete reporting for the GHG inventory. Even within the proposed rule, EPA uses blowdown vent and fugitive in different ways and with different meanings than presented in this definition.

API suggests adding the following definition for *Carbon Dioxide*: "A colorless, odorless, non-poisonous gas that is a normal component of ambient air. Carbon dioxide is a product of fossil fuel combustion. Although CO_2 does not directly impair human health, it is a greenhouse gas that traps terrestrial (i.e. infrared) radiation and contributes to the potential for global warming."

Carbon dioxide production well §98.6 (p. 16617): "*means any hole drilled in the earth to extract a carbon dioxide stream from a geologic formation or group of formations which contain deposits of carbon dioxide*." API is concerned that wells drilled to produce hydrocarbons that have a significant concentration of associated carbon dioxide could be inappropriately considered a "carbon dioxide production well" even though each well is permitted by the state according to production type. API suggests the definition be changed to read:
Carbon dioxide production well means any hole drilled in the earth for the primary purpose of extracting carbon dioxide from a geologic formation or group of formations which contain deposits of carbon dioxide.

Carbon dioxide equivalent (CO_2e) §98.6 (p. 16617): The EPA definition is unclear. API suggests the following definition from the API Compendium: "The mass (reported in metric tones) of a greenhouse gas species multiplied by the global warming potential (GWP) for that species. It is used to evaluate emissions of different greenhouse gases on a common basis – the mass of CO_2 emitted that would have an equivalent warming effect."

Condensate §98.6 (p. 16618): API requests the following alternative definition: "Liquid formed by the condensation of a liquid or gas; specifically, the hydrocarbon liquid separated from natural gas because of changes in temperature and pressure when the gas from the reservoir was delivered to the surface separators. Such condensate remains liquid at atmospheric temperature and pressure."

Connector §98.6 (p. 16618): Suggest removing the "Note: Connector is not limited to the definition above." This part of the definition is too open ended and leaves the definition too broad.

Continuous Emissions Monitoring System §98.6 (p. 16618): EPA's definition of CEMS includes a requirement for "readings every 15 minutes" which is not appropriate for a definition.

Compressor fugitive emissions §98.6 (p. 16618): 'Compressor fugitive emissions' are defined as *"natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including but not limited to open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves."* The definition of *"Compressor Fugitive Emissions"* is ambiguous. It would be helpful to add boundary definitions for a compressor, such as "on skid" or "in between shut down valves." Also API requests clarification on why EPA is providing separate definitions for "compressor fugitive emissions", "centrifugal compressor dry seals fugitive emissions" and "centrifugal compressor wet seals fugitive emissions." API also requests clarification on what is meant by *"close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates".*

Crude Oil §98.6 (p. 16618): The definition is too broad and could be interpreted to include natural gas. API prefers the definition from the Glossary of Oilfield Production Terminology (GOT): "A mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities.

Destruction efficiency §98.6 (p. 16618): The definition for "Destruction Efficiency" should not be specific to greenhouse gas emissions. In addition, the rule should provide only one definition for this term.

Emergency generator §98.6 (p. 16620): The definition of 'Emergency generator' states *"the hours of operation per calendar year for performance testing shall not exceed 100 hours."* API requests that the specification of hours be removed from the definition of emergency generators. It is not reasonable to limit the number of hours. In addition, the definition in regards to the duration of operation for performance testing should be revised to be consistent with the existing

Clear Air Act (CAA) regulations definition for emergency equipment that state testing of units should be minimized, but there is no time limit on the use of emergency equipment in emergency situations and for routine testing and maintenance. Refer to Stationary Combustion Turbines MACT (§63.6175) and Stationary Reciprocating Internal Combustion Engines MACT (§63.6675).

API suggests adding the following definition for "*emission factor*" from the API Compendium: "The emission rate for a particular emission source per unit of the source, when related to the activity data (e.g., amount of fuel consumed or counts of emission sources) results in absolute greenhouse gas emissions."

Engineering estimates §98.6 (p. 16620): API suggests removing the term "fugitive emissions" from the definition of Engineering Estimates. Engineering estimates should not be restricted just to fugitive emissions. The suggested revisions is: "For the purpose of this rule, an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as including, but not limited to dimensions of containment, actual pressures, actual temperatures, and compositions." Engineering estimate can also refer to estimated fuel use based on engine run time, load, heat rate curve, and fuel characteristics.

Facility §98.6 (p.16620): EPA should clarify the definition of "facility" as it applies to offshore petroleum and natural gas production platforms. Some platforms under common ownership are connected by above sea level bridges and pipe ways though the structures of the platforms are not in physical contact. Such platforms should be considered one facility. Also, platforms only connected to common pipes below sea level to transport oil and gas from wells and that are not in physical contact should be considered separate facilities since they do not meet the "facility" definition. Thus, API suggests the definition of facility be revised to include the following clarification: "For purposes of this definition, offshore petroleum and natural gas production platforms should be treated as contiguous or adjacent only if connected by physical structures above sea level (e.g. bridges, pipe ways, etc). Connections below sea level such as export oil and gas pipelines do not make otherwise separate facilities contiguous or adjacent."

Feedstock §98.6 (p. 16620): It is not clear if the definition specifically excludes crude that is used for fuel. API requests clarification.

Flare stack fugitive emissions §98.6 (p. 16620): API strongly disagrees with the definition of "Flare stack fugitive emissions" that classifies this emission source as a fugitive emission. This runs counter to other EPA programs and the generally recognized classification of flaring as combustion.

Fuel gas (Still gas) §98.6 (p. 16621): EPA's definition for fuel gas (still gas) needs to be more clearly defined. It is not clear how this term differs from the separate definition of "refinery fuel gas (still gas)". EPA should explicitly note that this definition does not include natural gas used as a fuel (gas) whether produced from oil and natural gas systems, obtained in the natural gas supply chain, or purchased as finished natural gas.

Fuel gas systems §98.6 (p. 16621): EPA's definition for fuel gas systems needs to be more clearly defined. EPA should explicitly note that this definition does not include natural gas fuel systems located at oil and gas system facilities.

Fugitive emissions §98.6 (p. 16621): As noted in a previous comment, API requests that EPA adopt a definition that is consistent with other long term practices of defining fugitive emissions.

Heating value §98.6 (p. 16622): API suggests the following definition: "Heating Value: The amount of energy released when a fuel is burned completely. (See also HHV and LHV).

HHV: Higher Heating Value or Gross Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water is completely condensed (liquid state) and the heat is recovered.

LHV: Lower Heating Value or Net Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered. The difference between the HHV and LHV is the latent heat of vaporization of the product water (i.e., the LHV is reduced by the enthalpy needed to vaporize liquid water).

Miscellaneous Products §98.6 (p. 16623): API suggests the addition of the word "refined" to the definition of Miscellaneous Products. The suggested revision is: "*Include all refined petroleum products not classified elsewhere. It includes petrolatum lube refining by-products (aromatic extracts and tars) absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils.*"

Natural gas processing facilities §98.6 (p. 16623): The definition of "Natural gas processing facilities" needs clarification. As written, with the use of "and", the definition implies that all conditions must be met: *"engaged in the extraction of natural gas liquids from produced natural gas; fractionation of mixed natural gas liquids to natural gas products;* ***and*** *removal of CO_2, sulfur compounds, nitrogen, helium, water,* ***and*** *other contaminants."*

Offshore petroleum and natural gas production facilities §98.6 (p. 16624): 'Offshore platform pipeline fugitive emissions' are defined as *"natural gas above the water line released from piping connectors, pipe wall ruptures and holes in natural gas and crude oil pipeline surfaces on offshore production facilities."* EPA should delete the definition of and reference to Offshore platform pipeline fugitive emissions". This emission source type does not seem rational nor do the monitoring requirements specified in 98.232 (a) (15) seem either feasible or rational.

Oil/water Separator §98.6 (p. 16624): EPA's definition of "Oil/water separator" should specifically exclude sumps and stormwater ponds.

Operator §98.6 (p. 16624): EPA's definition of "Operator" refers to a single person. API suggests the following revision: "*Operator* means any *entity* that operates or supervises a facility or supply operation."

Owner §98.6 (p. 16624): EPA's definition of "Owner" refers to a single person. API suggests the following revision: "*Owner* means any *entity* that has legal or equitable title to, has a leasehold interest in, or control of a facility or supply operation."

EPA does not define the terms "*Process Unit*" or "*Process Vent.*" These terms are used throughout the rule and need clarification.

Production Process Unit §98.6 (p. 16625): EPA's definition of "Production process unit" relates it only to CCS operations: "*Production process unit* means equipment used to capture a carbon dioxide stream." This is a common term and it is not appropriate to apply such as narrow definition.

Process Gas §98.6 (p. 16625): Process gas is defined as any gas generated by an industrial process such as petroleum refining. EPA should clarify if the definition applies to gas generated during normal operation or if it also applies to gases generated during startups and shutdowns, maintenance (such as blowdown vents or equipment purging), emergency situations (such as relief valve vents). If these vents are covered by the rule, the quantification of emissions should be handled under the de minimis threshold previously discussed or calculated using engineering analysis rather than in accordance to the monitoring requirements proposed in the rule for example in Subpart C.

Sour natural gas §98.6 (p. 16626): Sour natural gas is defined as natural gas that contains significant concentrations of hydrogen sulfide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines. EPA broadens the definition by including CO_2. Typically, commercially saleable natural gas contains about 4 to 8 ppm of hydrogen sulfide. States typically define a higher hydrogen sulfide concentration as sweet gas such as in the TCEQ 30 TAC 101.1 definition.

Storage Tank §98.6 (p. 16626): The use of the word "other" in EPA's definition of "Storage Tank" is confusing: "s*torage tank* means **other** vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support." In addition, the definition is broad enough and could be interpreted to include sumps. Based on the methods in the subpart it does not appear EPA intended to cover sumps as a storage tank. API recommends specifically excluding sumps and or other similar units. An example of a rule (63.2406) where EPA has done this is below.

> *Storage tank* means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, or reinforced plastic) that provide structural support and is designed to hold a bulk quantity of liquid. Storage tanks do not include:
>
> (1) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
> (2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
> (3) Bottoms receivers;
> (4) Surge control vessels;
> (5) Vessels storing wastewater; or
> (6) Reactor vessels associated with a manufacturing process unit.

Storage wellhead fugitive emissions §98.6 (p. 16627): "storage station wellhead" is referenced in the definition of storage wellhead fugitive emissions but is not defined. EPA should clarify if this is different from the definition of wellhead.

Storage station fugitive emissions §98.6 (p. 16627): Natural gas storage station is referenced in the definition of storage station fugitive emissions but is not defined.

Uncovered anaerobic lagoon §98.6 (p. 16627): EPA's definition of "Uncovered anaerobic lagoon" contains information that is not appropriate for a definition. The text: "*Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.*" should be deleted.

You §98.6 (p. 16628):EPA's definition of "You" presumes that the reader is the owner/operator. API finds it odd that this definition is included in the regulation.

Subpart C - General Stationary Fuel Combustion Sources (98.30)

a. EPA Requested Feedback

11. *"[…] given the unit-level approach for calculating CO_2 emissions, EPA is requesting comments on the use of more technology-specific CH_4 and N_2O emission factors that could be applied in unit-level calculations." (p. 16485)*
API Comments: API supports EPA's use of fuel-based CH_4 and N_2O emission factors, consistent with aggregation of combustion sources using common fuel gas supplies. Requiring "unit specific" CH_4 and N_2O factors would eliminate the option for aggregation of small sources and the "one-meter" concept where a uniform fuel gas is used throughout a facility and would drive the installation, maintenance, data capture and recording, and QA/QC requirements for metering or monitoring at a unit specific level. Given the small (about 1%) of CO_2e's that CH_4 and N_2O make up from combustion sources this is not cost/value effective. This could be particularly problematic on offshore platform installations.

12. In Subpart MM (Suppliers of Petroleum Products), EPA requests *"comment on whether reporters should be allowed to combine default CO_2 emission factors to develop alternative factors for fuel reformulations according to the volume percent of each fuel component" (p. 16572).* This issue also affects Subpart C. As there are currently no default emission factors for fuel mixtures, Tiers 1 and 2 cannot be used to estimate combustion emissions from fuel mixtures. However, since CO_2 emissions are based on the carbon content of the fuels, multiplying the volume of each pre-mixed fuel by its respective fuel-based emission factor would result in an accurate estimate of CO_2 for the fuel mixture. Clarification should be added to Subpart C as to how emissions from fuel mixtures should be estimated, without the use of carbon content measurements or CEMS.

b. Additional API Comments

13. As discussed in comment III.3, API requests that the reporting rule allow up to 5% of the emissions to be declared as “de minimis”, allowing simplified emission estimation methods for demonstrating compliance with this emission level. This should include small combustion sources.

14. Page 16631/Sec 98.32: Stationary combustion units are required to report at the unit level. Reporting at the unit level is overly burdensome. In Section 98.36 (c) (3) on Page 16637, aggregation of small units is permitted; however, some sites have no metering. API requests the use of small unit aggregation methods based on parameters such as design capacity, hours of operation, load, and fuel characteristics.

15. §98.33: Offshore facilities submit triannually an emission inventory to MMS under the GOADS system for criteria pollutants. Offshore facilities should be allowed to use the same calculations under the GOADS[7] systems for GHG reporting since MMS has been granted jurisdiction for offshore air emissions.

16. §98.33(a)(4)(ii), Equation C-6. The units for the conversion factor 5.18×10^{-7} should be changed from (tons/scf-%CO_2) to (metric tons/scf-%CO_2). This change is consistent with the conversion of the original constant [5.7×10^{-7} (tons/scf-%CO_2), as presented in 40 CFR §75, Appendix F] to metric units for the proposed rule.

17. §98.33(a)(4)(iii), Equation C-7. The units for the variable CO_2 (calculated using Equation C-6) should be changed from (tons/hr) to (metric tons/hr). This change is consistent with the stated units for the variable CO_2 as defined in Equation C-6.

18. Based on preamble language, API is concerned that the EPA believes any CEMS can be easily converted to a CO_2 CEMS in Tier 4. API disagrees that this is a simple conversion. For this reason, clarification should be added to §98.33(b)(5)(ii). In addition, clarification should be added to §98.33(b)(5)(ii)(D) and (E) to indicate whether the “installed CEMS” are any type of CEMS (i.e. criteria pollutant CEMS or CO_2 CEMS) or a specific type of CEMS (e.g. CO_2 CEMS).).

For gaseous fuels metering of fuel volume coupled with analysis of carbon content is likely to be more accurate than direct measurement of CO_2 emissions with a CEM.

API will provide additional information on this topic.

19. §98.33(b)(5)(ii) and (iii) – EPA should revise paragraphs §98.33(b)(5)(ii) and (iii) to emphasize that the Tier 4 calculation methodology must be used for units that combust solid fuels or MSW and that meet the requirements in the subparagraphs. As stated in the preamble on page 16483 “The most stringent emissions calculation methods would apply to large stationary

[7] The GOADS effort is *similar* to an EIS for an onshore, Title V facility. Under GOADS, operators submit "raw" data to MMS and MMS does the actual emissions calculations. The raw data includes information such as component counts and stream composition. Since the data is already being collected for MMS, reporters should be allowed to use the same data to calculate GHG emissions for the reporting rule.

combustion units that are fired with solid fuels and that have existing CEMS equipment." Thus, if a combustion unit does not burn solid fuel or MSW, it is optional for the owner or operator to use Tier 4 (CEMS) according to §98.33(b)(5)(i). API suggests revising §98.33(b)(5)(ii) and (iii) to read as follows:

(5) The Tier 4 Calculation Methodology:
(I) May be used for a unit of any size, combusting any type of fuel.
(ii) Shall be used for a unit if:
(A) The unit has a maximum rated heat input capacity greater than 250 MMBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW, and
(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel, and
(C) The unit has operated for more than 1,000 hours in any calendar year since 2005, or
(D) The unit meets the criteria in (B) and (C) directly above, and
(E) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit, and
(F) The installed CEMS include a gas monitor of any kind, a stack gas volumetric rate monitor, or both and the monitors have been certified in accordance with the requirements of Part 75 of this chapter, Part 60 of this chapter, of an applicable State continuous monitoring program, and
(G) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation of the unit's operating permit, to undergo periodic quality assurance testing in accordance with Appendix B to Part 75 of this chapter, Appendix F to Part 60 of this chapter, or an applicable State continuous monitoring program.
(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit:
(A) Has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor, and
(B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) ~~and (C) of~~ this section, and
(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section.

20. Pg 16635, §98.33(c)(4) – Section 98.33(c)(4) refers to Table C-4 when referencing CH_4 and N2O emission factors but there is no Table C-4. The reference should be revised to Table C-3.

21. §98.33(d), Equation C-11. This equation appears to be missing a term – a conversion "moles acid gas removed/mole sorbent." The units of the equation as presented do not currently result in metric tons CO_2 emitted.

22. §98.34. Calibrated flow meters are not addressed for a Tier 1 or Tier 2 calculation approach. If using Tiers 1 or 2, rated horsepower/operating hours etc should be acceptable as legitimate

"company records to quantify fuel consumption." Note, equation definitions for Tiers 1 and 2 indicates fuel flow, but do not use the term "company records." The inconsistency is vague and confusing. API is assuming that Tiers 1 and 2 do not require fuel meters, and that the use of company records includes estimation methods as outlined in the Compendium, based on operating hours and ratings.

23. §98.34(c) and §98.34(d)(3) require routine measurement of the higher heat value (HHV) and carbon content of fuels, respectively. The reporter should be allowed to use fuel specifications that include, but are not limited to, regulatory requirements, data provided by fuel suppliers, and specifications set by the reporter to determine HHV and carbon content. The frequency for determining HHV or carbon content from data obtained from a fuel supplier should be the same frequency for obtaining the data from the supplier. Also, similar to other CAA rules, the rule should include an option to decrease the frequency of sampling to annually if several consecutive measurements show minimum variation in the HHV or carbon contents.

24. §98.34. Where monthly fuel analyses are required, characterizations performed by the fuel supplier should be acceptable. It is noted in the preamble (p. 16484) that "*EPA considered allowing affected facilities to rely exclusively on the results of fuel sampling and analysis provided by fuel suppliers, rather than performing periodic on-site sampling for all variables [but EPA] decided not to propose this because in most instances, only the fuel heating value, not the carbon content, is routinely provided by fuel suppliers.*" If a fuel supplier provides carbon content, this data should be permitted in Tier 3 calculations. Note that the implication of this finding is not limited to subpart C, but has implications for other subparts (P, Y, etc.) Allowing a facility to substitute carbon contents specified by the fuel supplier will assist in reducing the overall reporting burden. API suggests one annual value from the supplier should be acceptable as the carbon content of these fuels is very stable.

25. §98.34(d)(1). The statement *"All oil and gas flow meters"* should be revised to *"All liquid and gas flow meters"*.

26. §98.34(d)(3). Where the Tier 3 Calculation Methodology is used, reporters are required to determine the carbon content of natural gas, biogas, liquid fuels, and solids fuels monthly and of other gaseous fuels such as refinery gas and process gas on a daily basis. For many refinery and natural gas operations, the carbon content of gas streams does not vary significantly enough to warrant daily determination. EPA acknowledges in the definition of natural gas provided in §98.6 that the composition of fuel gas and process gas are similar to natural gas. Thus, EPA should revise the requirement in §98.34(d)(3) to specify that the reporter must determine the content of gaseous fuels monthly. Daily sampling is excessive for fuels that are fairly stable in composition. API recommends the use of the natural gas factor in Table C-1 or where the gas stream does fluctuate with operational changes, to determine a sampling frequency that is consistent with the variability of the stream. In addition, engineering analysis should be allowed to estimate carbon content instead of sampling for streams where there are safety concerns such as process gases that are maintained at high temperature to avoid liquid accumulation.

The oil and gas flow meters used for this category have been installed and are operated following a wide variety of procedures. The reporter should maintain them in an appropriate manner, but specifying the exact appropriate methods would be very difficult for EPA. API recommends that reporters be allowed to determine the best methods and necessary frequencies for calibration and/or verifying flow measurement devices.

API offers the following revised language for §98.34(d) [Page 16636]:

Sec. 98.34 Monitoring and QA/QC requirements.

(d) For the Tier 3 Calculation Methodology:

(1) All oil and gas flow meters (except for gas billing meters) shall be calibrated or verified on a documented schedule consistent with good industry practice, using an applicable industry standard method or the calibration procedures specified by the flow meter manufacturer or developed and documented by the facility for the device. Fuel flow meters shall be recalibrated/reverified either annually or following good industry practice.

(2) Oil tank drop measurements (if applicable) shall be performed according to one of the methods developed by a consensus standards organization.

(3) The carbon content of the fuels listed in paragraphs (c)(1) and (2) of this section shall be determined monthly. For other gaseous fuels (e.g., refinery gas, or process gas), monthly sampling and analysis is required to determine the carbon content and molecular weight of the fuel. If a specific gravity or density analyzer is used to measure the properties of the gas, a correlation with the carbon content must be demonstrated by periodic sampling. An applicable method listed in Sec. 98.7 shall be used to determine the carbon content and (if applicable) molecular weight of the fuel.

27. §98.34(d)(1) and (3) (Page 16636): The continuous monitoring of flow rate and daily sampling for carbon content proposed in §98.34(d)(1) and (3) for process gases assumes the vents are continuous. Some process gas vents, however, are intermittent or are only generated during emergency situation. Quantification of such process gases should be handled under a de minimis threshold previously discussed in the comments or calculated using engineering analysis.

28. [Page 16637] Sec. 98.35 Procedures for estimating missing data.
API offers the following revised language for this section's paragraph (b) at this time.[8]

(b) For all units that are not subject to the requirements of the Acid Rain Program, when the Tier 1, Tier 2, Tier 3, or Tier 4 calculation is used, perform missing data substitution as follows for each parameter:

(1) For each missing value of the heat content, carbon content, or molecular weight of the fuel, and for each missing value of CO_2 concentration and percent moisture, the substitute data value shall be the quality-assured value of that parameter immediately preceding the missing data incident. If the quality assured value immediately following the missing data incident is different by more than ten percent of the preceding value, the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident, shall be used. If, for a particular parameter, no quality-assured data are available prior to the

[8] Note the Times Roman italics font indicates areas where revisions have been made; the Courier font is unchanged from the proposed MRR.

missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of stack gas flow rate, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the flow rate, fuel usage, or sorbent consumption, based on all available process data(e.g., steam production, electrical load, and operating hours). The owner or operator shall document and keep records of the procedures used for all such estimates.

29. §98.37. References to §98.35(a)(1) and §98.35(a)(4) should be changed to §98.35, as §98.35(a) does not have subdivisions.

30. §98.38, Table C-1: The emission factor for "Coke" is not specified to be a particular type of coke (e.g. petroleum coke versus catalyst coke).

31. §98.38, Table C-3 should include default CH_4 and N_2O emission factors for flexi gas, consistent with the emissions factors adopted in California. Flexi gas is a low Btu gas produced during FLEXICOKING™, where thermal cracking converts heavy hydrocarbons into light hydrocarbons. The applicable California emission factors for flexi gas (referred to as a derived gas, low BTU gases) are 0.3 g CH_4 per MMBtu and 0.1 g N_2O per MMBtu.

32. §98.38, Table C-3. CH_4 and N_2O factors are not defined, but should be added, for the following fuel types currently listed in §98.38, Table C-1: Ethane; Biogas; Isobutane; n-Butane; Natural Gasoline; Other Oil (>401 def. F); Pentanes Plus; Petrochemical Feedstocks; Special Naphtha; and Unfinished Oils.

33. §98.38, Table C-3. The fuel type of "Totes" should be "Tires".

34. §98.38, Table C-3. Certain factors do not match those presented in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, when converted to a HHV basis. Factors should be revised as follows:

a. Coal CH_4 factor of $1.0x10^{-2}$ should be $1.0x10^{-3}$;
b. Landfill Gas CH_4 factor of $9.0x10^{-4}$ should be $9.5x10^{-4}$;
c. Landfill Gas N_2O factor of $1.0x10^{-4}$ should be $9.5x10^{-5}$;
d. Natural Gas and Refinery Gas CH_4 factor of $9.0x10^{-4}$ should be $9.5x10^{-4}$; and
e. Natural Gas and Refinery Gas N_2O factor of $1.0x10^{-4}$ should be $9.5x10^{-5}$.

Subpart D - Electricity Generation (98.40)

35. 98.40 (a): By definition, the rule includes all facilities that generate electricity. This broad coverage includes cogeneration and the self-generation of electricity for remote locations (such as offshore platforms or North Slope facilities) that are utilized in the oil and gas industry. Subpart C provisions for stationary combustion already account for emissions from these units.

API requests that EPA eliminate the unit-level reporting requirements for site located electricity generation units where the majority of power (>50%) is used at the site. Maintaining the requirement for unit level reporting will preclude the aggregation of small sources and sources supplied with a uniform fuel gas options, provided in Subpart C, that greatly simplify the metering/monitoring/reporting/recordkeeping burden and costs. This is particularly problematic for offshore production platforms and remote Oil and Gas facilities where electricity is typically self-generated using natural gas as a fuel.

Subpart P - Hydrogen Production (98.160)

a. EPA Requested Feedback

36. *"The first method requires direct measurement of emissions by CEMS from all reporting facilities […] We invite comment on the practicality of adopting the first method." (pp. 16514-16515)*
API Comments: API supports keeping both options in the final rule, giving facilities the flexibility to install CEMS if that is their preferred approach.

b. Additional API Comments

37. §98.160. The definition in Subpart P uses the phrase "transformations of feedstocks." There is a concern that the term "transformation" could be broadly interpreted to apply to operations that do not emit CO_2 in the generation of H2. The rule should specify by name which processes are included versus excluded. API suggests that the detail in the technical support documentation on this topic be brought into the rule.

38. §98.160(c). Subpart P includes hydrogen production facilities located within a petroleum refinery and that are not owned or under the direct control of the refinery owner and operator. Captive hydrogen plants, where owned or operated by a third party, should not be reported as refinery emissions, even if located inside the refinery fence. The regulation should be revised to require the party that owns or operates the hydrogen plant to report the hydrogen plant emissions.

39. §98.160, §98.163. Clarification should be added that the methodologies presented in Subpart P apply only to hydrogen plants that vent CO_2. Most modern steam CH_4 reforming hydrogen plants are built with a pressure swing absorption (PSA) system without a CO_2 removal step. PSA systems without a CO_2 removal step do not vent CO_2 emissions, as all of the fuel exiting the PSA unit (purge gas) is routed to the reformer furnace. This is shown in Figure H-1 of the Technical Support Document for Hydrogen Production (EPA, 2008). Emissions from steam CH_4 reforming plants with a PSA unit and no CO_2 removal step will only be from combustion of the PSA purge gas in the reformer furnace. These combustion emissions would be estimated using the methodologies described in Subpart C, as indicated in §98.162(b).

40. §98.163. A material balance approach based on hydrogen production rate is not presented in the proposed rule. The Compendium provides a CO_2 emission estimation method based on the amount of H_2 produced and the stoichiometric ratio of H_2 formed to CO_2 formed (note that this approach is not ideal where the feedstock gas contains H_2)

41. §98.164(c). The carbon content analysis requirements for hydrogen plant feedstocks are not completely consistent with the carbon content analysis requirements for combustion sources under subpart C. Under subpart P, the feedstock carbon content must be analyzed monthly at a minimum. However, under subpart C, carbon content analyses are gas-specific—the carbon contents for natural gas and biogas must be analyzed monthly, but the carbon content for other gases must be analyzed daily. As noted above in comments for Subpart C, API supports the use of the natural gas factor in Table C-1, or where the gas stream composition does fluctuate with operational changes, allow the reporters to determine a sampling frequency that is consistent with the variability of the stream.

42. [Page 16664] Sec. 98.164 Monitoring and QA/QC requirements.
API offers the following revised language for this section's paragraph (d) at this time.

> *(a) Facilities that use CEMS must comply with the monitoring and QA/QC procedures specified in Sec. 98.34(e).*
> *(b) The quantity of gaseous or liquid feedstock consumed must be measured continuously using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.*
> *(c) You must collect a sample of each feedstock and analyze the carbon content of each sample using appropriate test methods incorporated by reference in Sec. 98.7. The minimum frequency of the fuel sampling and analysis is monthly.*
> (d) All fuel flow meters, gas composition monitors, and heating value monitors shall be calibrated *or verified following good manufacturing practice, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration/verification procedures specified by the flow meter manufacturer may be used.*

Subpart W - Oil and Natural Gas Systems (98.230)

a. EPA Requested Feedback

43. *EPA seeks comment on using either*
1) "performance standards for fugitive emissions detection instruments and usage such that all instruments follow a common minimum detection threshold. […] In such a case all detected emissions from components subject to this rule would require measurement and reporting" or
2) providing "an emissions threshold above which the source would be identified as an 'emitter' for emissions detection using Organic Vapor Analyzers or Toxic Vapor Analyzers […]" or alternatively "detecting emissions sources using the infrared detection instrument and then verifying for measurement status using the emissions definition for Organic Vapor Analyzers or Toxic Vapor Analyzers." (p. 16535)
API comments: As stated above, API does not support the leak detection and quantification approach that EPA has taken for this rule. However, should EPA maintain these requirements API has the following comments regarding EPA's questions directly above.

It is inappropriate that additional standards and optical gas imaging devices be included in this rule. A new set of requirements is not necessary when the use of IR cameras has been detailed in the Alternative Work Practice (AWP) – although API would like to point out that many of the requirements in the AWP are not relevant to the focus of this rule.

API proposes that when a leak is detected using a camera, that an emission factor (such as those developed by API or EPA) can be applied to quantify the emissions. If a camera is not used, for example when an organic vapor analyzer (OVA) is used, an EPA correlation approach can be applied to quantify emissions.

The use of performance standards may be acceptable once standardized methods developed by consensus are available. API and its member companies offer to work with EPA to define an appropriate detection threshold, a key objective of method standardization. However, EPA would need to propose a threshold for public comment since a threshold is not in the regulatory text. Any significant changes to the regulatory text would need to be re-proposed for comment.

If an OVA is used for leak screening, API recommends that 10,000 ppmv serve as the screening level that triggers a measurement because this threshold is probably most consistent with the high volume sampler detection limit. As technologies and methods mature, more concise methods can be developed for identifying the leak measurement threshold. Developing methods separate from the rule will provide a more expedient path to advancing the technical approach for reconciling this issue.

44. §98.230. Refer to comments under Subpart A - General Provisions for comments on the definitions of facility as it applies to offshore platforms, natural gas, and offshore platform pipeline fugitive emissions.

45. §98.230. The definitions of “natural gas processing facility” and “natural gas transmission compression facility” are not clear when trying to determine the boundary around each facility. The lack of clarity is compounded because a definition of onshore production facility is not included in the rule, since those facilities are not subject to the rule. For example, compressors and dehydration equipment may be located at a well head, which the oil and gas industry considers a production facility but could be construed as a natural gas processing facility or natural gas transmission compression facility under the proposed definitions in the reporting rule. API requests clarification of the equipment that is included in the “natural gas processing facility” and “natural gas transmission compression facility.”

Natural gas production facilities may be centralized within a natural gas producing area or located at individual wellhead locations. The primary purpose of these facilities is to treat natural gas at or near the point of production in preparation for entering collection systems or main transmission pipelines. Production facilities are located upstream from main transmission pipelines and natural gas processing facilities.

API would recommend limiting the definition of Natural Gas Processing Facilities to what is commonly defined as a Natural Gas Processing Plant that would comprise gas processing, sweetening and dehydration to produce pipeline quality gas that is ready for transmission or distribution.

API also recommends that the definitions of "Natural Gas Processing Facilities" and "Offshore Petroleum and Natural Gas Production Facilities" be mutually exclusive as both definitions contain many of the same process steps and will result in confusion amongst both the industry and regulatory communities.

Natural Gas Processing Facilities – are facilities that are primarily engaged for commercial purposes in the recovery or extraction of liquid hydrocarbons from produced natural gas; fractionation of natural gas into natural gas products (e.g. propane, ethane, etc.) or primarily engaged in sulfur or CO_2 recovery from produced natural gas. These facilities may or may not have compression based on the disposition of gases after processing.

Natural Gas Transmission Facilities – are compression facilities whose primary purpose is to maintain or boost pipeline pressures along main natural gas transmission pipelines or pipeline systems. These facilities may be inline booster stations or located at natural gas storage facilities or natural gas processing facilities.

46. §98.232 (a)(24) requires reporting "transmission station fugitive emissions.". The definitions in §98.6 do not define a transmission station, but do define a natural gas transmission compression facility. This implies that only fugitive emission from the compressor stations are included in the rule and not fugitive emissions from other natural gas transmission stations (metering and pressure regulating).

47. 98.233 (d): API recommends removing the requirement for leak detection from the following sources listed in 98.232 (a):

- (1)Acid gas removal (AGR) vent stacks; (6)Compressor wet seal degassing vents; (7)Dehydrator vent stacks; (8)Flare stacks; (22) Storage tanks: These sources are designed to have emissions at all times unless shut-down and there is nothing to be gained by doing an annual leak detection; and
- (11)Natural gas driven pneumatic pumps; (12)Natural gas driven pneumatic manual valve actuator devices; (13) Natural gas driven pneumatic valve bleed devices: These sources are designed to have emissions while operating and it is sufficient to determine if they are operating without doing a leak detection using an optical or analyzer device.

48. The proposed 40 CFR § 98.234(a), requires the use of "*methods described in paragraphs (d) or (e) in this section to conduct annual leak detection of fugitive emissions from all sources listed in § 98.232(a)…*"These protocols have not benefited from the rigorous testing and expert review required by major standard-setting organizations such as ASTM, ASME, API, and the American Gas Association (AGA). As a result, the proposed rule creates a risk that the various testing methods in the proposed 40 CFR § 98.234 will not give accurate results or be applied consistently. Indeed, many of the protocols in the proposed rule are not adequately specified and likely to generate unreliable data.
For example:

- In 98.234(d)(2), (4). The infrared detection protocol requires the operator to inspect the emissions source from "*multiple angles*" without "*visual obstructions*" and in "*favorable conditions*," without elaborating on the correct procedure for doing so.
- In 98.234(f). The high volume sampler measurement protocol requires that the equipment be operated by a "*trained technician*" who is "*conversant*" with sampling techniques, but does not specify what operating procedures and measurement methodologies the technician would be expected to know. In addition, the protocol directs the technician to use "*anti-static wraps or other aids*" if the high volume sampler is not able to completely capture all emissions from the source, but does not specify how such leakage is to be detected or how these aids are to be used.
- In 98.234(g)(5). The calibrated bag protocol states that the operator must "*obtain consistent results*" when measuring the amount of time required to fill the bag, but does not provide a benchmark for consistency.

EPA's approach will also hinder the adoption of more advanced measurement techniques, because a new rulemaking will be required if EPA ever chooses to revise the protocols in the proposed rule.

A better approach would be for EPA to engage industry leaders and at least one of the major standard-setting organizations to develop consensus protocols for detection and direct measurement of fugitive emissions. The agency has wisely chosen to defer to such consensus standards for CEMS in Subpart C portion of the proposed rule, and should seek to do the same in Subpart W. Consensus standards would provide assurance that the direct measurement protocols required in the rule reflect the state of the art and are being applied in a consistent matter that is uniformly understood within the industry. This would also justify deferring the effective date of the final rule.

These methods would not have to be written directly into the final rule, but could instead be provided in a guidance document that could be easily revised in step with field experience and advances in measurement technology. API is willing to be a constructive partner in developing such standards.

49. 98.234 (j)(2) API recommends removing the direct flow measurement and vapor space analysis requirements for storage tank emissions. As stated, EPA's proposed requirements for storage tanks are:

(i) Measure the hydrocarbon vapor emissions from storage tanks using a flow meter described in paragraph (h) of this section for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.
(ii) Record the net (related to working loss) and gross (related to flashing loss) input of the storage tank during the test period.
(iii) Record temperature and pressure of hydrocarbon vapors emitted during the test period.
(iv) Collect a sample of hydrocarbon vapors for composition analysis.

API Comments: This is overly prescriptive, burdensome, costly, and problematic from a number of perspectives and is not necessary to reliably estimate emissions from storage tanks – whether or not flashing is occurring.

Many tanks at the types of facilities covered by this rule produce very little liquid and measurement across *"a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank"* will require continuous measurement for several months – which is not feasible or reasonable. Similarly, measurement *"for a test period that is representative of the normal operating conditions of the storage tank throughout the year"* may require measurement across an entire year where large variations in diurnal and seasonal conditions occur.

Emissions flow rates and compositions for flashing tanks can be reliably determined through the use of process simulation models such as HySys or ProSim. These are the same models which are used to design facilities and processes worth billions of dollars and are certainly robust enough for emission determination. They have been in use for many years for determining tank emissions in a number of States (e.g. Wyoming) and areas and are becoming the "preferred" option for flashing determination. API requests that EPA enable the use of process simulation model approaches as an alternative to the direct flow measurement and compositional analysis proposed in the MRR.

API recommends allowing the reporters to use any method available for at least the 2010 reporting year to allow better method development. The sampling of emissions of a fixed roof tank is a major exercise under ideal circumstances, and it would be extremely impractical on a routine basis. For external floating roof tanks it is impossible to obtain a representative sample.

The very wide range of uncertainties that vapor space sampling gives would increase the overall uncertainty significantly. Sampling is only appropriate in special cases with significant experimental design, not routine operations. Relying on simulation calculations as in some of the other sections would give a more scientifically valid quantification.

[Page 16680] API offers the following revised language 98.234 paragraph (j) at this time.

(j) Parameters for calculating emissions from flare stacks, compressor wet seal degassing vents, and storage tanks.

(2) Estimate fugitive emissions from storage tanks as follows:

(i) The hydrocarbon vapor emitted from the storage tank shall be estimated using engineering calculations. The basis and all input data for the calculations shall be documented and retained.
(ii) Collect a sample of hydrocarbon vapors for composition analysis or calculate the probable evaporative loss from samples of the material using standard simulation packages.

Additionally, EPA ignores the fact that at many of the facilities which will be subject to this rule the storage tanks have vapor recovery or thermal control installed either to improve economics, to meet regulatory requirements in an air quality permit, to meet applicable of NSPS subpart K series requirements, or to improve safety (such as offshore production facilities/platforms). Tanks with VRU control are not significant sources of GHG's and API requests that they be excluded from the rule applicability. Tanks with thermal control would emit CO_2 from the control device rather than CH_4 from the tank – this would still require the vapor flow and gas composition to determine but is not recognized nor dealt with in Subpart W. API proposes that tanks with thermal control be allowed to use the process simulation model approach described above to determine flow and composition to the control device.

At many sites, particularly offshore production platforms, the tank vent cannot be safely accessed to enable direct measurement. MMS regulations prohibit the flaring or venting of produced natural gas from low-pressure storage vessels beyond very small amounts that are uneconomic to recover using vapor recovery units. Therefore on offshore deepwater facilities, most storage tank vapors are routed to vapor recovery, or to the platform combustion flare, located on the flare boom hundreds of feet above the deck, only if vapor recovery units are not functioning. In rare cases, tank vapors are sometimes routed to atmospheric vent in a safe location, such as on the flare boom hundreds of feet above the deck, or on a pipe rack extending beyond the edge of the platform deck. In none of these scenarios can the tank vent be safely accessed to enable flow measurement. API proposes that tanks where the vent cannot be safely accessed be excluded from the requirement to quantify and report emissions.

Additionally, offshore deepwater floating production facilities are often equipped with storage tanks located in the hull of the facility for diesel fuel storage. In addition, some facilities have storage tanks in the hull containing crude oil that can be used to flush subsea flowlines. These hull crude oil storage tanks are used very infrequently, for example in the event that a subsea flowline must be temporarily decommissioned. Tank vents for hull tanks are normally located in a safe location such as on the flare boom hundreds of feet above the deck. EPA's proposed engineering estimation methodology for quantification of emissions from storage tanks requires storage tanks be completely filled and pumped out while vapor emissions are measured. This method is not feasible for storage tanks located in the hull of floating facilities due to the nature of the tanks' service, and the inaccessible location of the tank vents. API therefore recommends that storage tanks located in the hull of floating offshore facilities be excluded from the requirement to quantify emissions.

API requests that tanks handling/storing hydrocarbon liquids with no or very low CH_4 content be excluded from the rule (e.g. diesel fuel tanks; stabilized oil tanks).

For tanks with low throughput (less than 10 bbls/day annual average) API proposes that E&P Tanks be allowed as the methodology for determination of tank flow and vapor composition. As EPA is aware, API is currently in discussions regarding updating the E&P Tanks simulation model. Because CH_4 is the species targeted from tanks, determination of standing and breathing losses should not be necessary.

50. §98.233. A default emission factor approach is not presented for the following source types: Glycol Dehydrators; Acid Gas Removal; Equipment Blowdowns; Natural Gas Driven Pneumatic Devices; Chemical Injection Pumps; and Equipment Leaks. API recommends utilizing the

emission factors provided in the API Compendium as part of a tiered emission estimation approach where these emissions are a small contribution to the facility total.

51. 98.232 (a) (1); §98.233 (d) (1); EPA should incorporate the two material balance approaches and the measurement approach described below for acid gas removal vent stacks. These methodologies will significantly reduce the complexity and cost while yielding emissions results that are at least as accurate as the modeling specified by EPA.

- Mass Balance Across the Amine Unit:
  - Metered volume of natural gas flow into or out of the unit
  - Minimum quarterly analysis of CO_2 content in gas entering and exiting the unit
  - Quarterly analysis of CH_4 content in the vent stream from the unit. If the CH_4 content of the vented gas does not vary more than 10% from the mean for 4 consecutive quarters then vent gas sampling shall move to annually.
  - GHG emissions would be calculated as follows:
    CO_2 = (Volume weighted CO_2 content difference (inlet – outlet)) x (annual volume of gas through unit)
    CH_4 = (CO_2 result) x (average CH_4 content of vent gas)

- Mass Balance Across the Facility:
  - Metered volume of natural gas inlet flow to the facility
  - Metered volume of natural gas exiting the facility
  - Fuel gas use as determined for Subpart C
  - Minimum quarterly analysis of CO_2 content in gas entering and exiting the facility
  - Quarterly analysis of CH_4 content in the acid gas vent stream. If the CH_4 content of the vented gas does not vary more than 10% from the mean for 4 consecutive quarters then vent gas sampling shall move to annually.
  - GHG emissions would be calculated as follows:
    CO_2 = [(Volume weighted CO_2 content into facility x (annual volume of gas into facility – fuel gas volume if taken prior to amine unit inlet)] – [(volume weighted CO_2 content in outlet gas) x (annual volume of gas exiting the facility)]
    CH_4 = (CO_2 result) x (average CH_4 content of vent gas)

- Metered Acid Gas Vent Flow:
  - Metered volume of acid gas flow from Vent
  - Quarterly analysis of CO_2 and CH_4 content in the acid gas vent stream. If the CH_4 content of the vented gas does not vary more than 10% from the mean for 4 consecutive quarters then vent gas sampling shall move to annually.
  - GHG emissions would be calculated as follows:
    CO_2 = (Volume weighted CO_2 content of acid gas vent stream) x (annual volume of gas vented)
    CH_4 = (Volume weighted CH_4 content of acid gas vent stream) x (annual volume of gas vented)

52. 98.232 (a) (11); 98.233 (d) (2). The volume of natural gas emissions from a pneumatic pump is a function of the amount of liquid pumped (displacement volume), the liquid outlet pressure from the pump, the gas pressure and temperature used as the pneumatic power gas, and the "mechanical efficiency loss" across the pump. In manufacturers information this relationship is typically described using a set of "pump curves." However it can be described mathematically as follows:

Gas volume = (((outlet pressure from the pump psig) + (atmospheric pressure psia))/14.7 psia) * (atmospheric temperature R/(460 R + gas temperature F) * (volume of liquid pumped in cubic feet) * (1+pump inefficiency)

Volume of liquid:

- Measured volume – or-
- Calculated volume: (gals/stroke of pump/7.48 gal/scf * number of strokes/min)

Pump inefficiency:

- Expressed as fractional decimal (e.g. 0.30)
- From manufacturer or assume default of 30% mechanical efficiency loss

GHG Emissions:
CO_2 = (Volume of gas above) * (CO_2 content of pneumatic power gas)
CH_4 = (Volume of gas above) * (CH_4 content of pneumatic power gas)

API requests that EPA should enable the methodology described above for pneumatic pumps as an alternative to that described in the proposed rule.

53. 98.232 (a) (12); 98.233 (d) (3) 98.234; Natural gas driven pneumatic manual valve actuator devices.
API Comments: API requests that EPA clarify why they believe this is a legitimate source category that exists in the oil and natural gas sector covered by the proposed rule. API members have indicated that they do not recognize any instance of this type of device occurring in their operations.

The measurement of emissions per valve actuation for each device where manufacturers information is not available that is required in 98.234 (i) (2) is entirely inappropriate. The gas volume emitted from a valve actuator is simply the amount of gas that is used to pressure up a diaphragm or piston and move a valve against pressure and is a function of the actuator bonnet size and actuation pressure. This volume can be easily calculated using standard engineering techniques or the volume per actuation from an actuator of the same size where manufacturer's information is available can simply be substituted. API requests that EPA replace the measurement requirement (bagging) in 98.234 with the engineering approach described above.

54. §98.233 (d) (4). The name of this source type, natural gas pneumatic valve bleed devices: type should be changed to "pneumatic control device" as that is the commonly understood and used term throughout the industry and, prior to this rule, by the agency community.

55. 98.234 (i) (2). EPA should incorporate an orifice calculation methodology for determining the emissions from a "high or continuous bleed" pneumatic control device in lieu of the measurement prescribed in the proposed rule. This is illustrated directly below:

$$q = 16330\left[1+\left(\frac{d}{D}\right)^4\right]d^2\left[H\left[29.32+0.3H\right]\frac{T_s G_s H_f}{T_f G_f H_s}\right]^{0.5}$$

Nomenclature

q =	*Gas rate, SCF/day*
d =	*Orifice diameter, inches*
D=	*Pipe/tubing inside diameter, inches*
H=	*Pressure, inches of mercury*
T=	*Temperature, Rankin*
G=	*Specific gravity relative to air*
H_S=	*Standard pressure, 29.99 in Hg*
T_s=	*Standard temperature, 520 Rankin*
G_s=	*Standard Specific Gravity, 0.6*

Subscripts

s=	*Standard conditions*
f=	*Flowing conditions*

References

1. GPSA Engineering Data Book, 10th Edition, 1987, Volume 1, Page 3-10, Equation 3-12

Furthermore, as stated, EPA is requiring measurement using one of the prescribed techniques for "each individual pneumatic device" where manufacturer's information is not available. API requests that either the measurement described in the rule or the orifice calculation described immediately above be required only once for each make and model of pneumatic device and applied to the entire population of the same device.

Pilot operated (no or low bleed devices) controllers operate entirely differently and only bleed when reversing the actuation of a pneumatically actuated valve. Emissions associated with these units are minimal and equal to the actuation volume for the valve actuator and the number of times the valve strokes. This is an excellent example of a de minimis source that EPA should exclude from the proposed rule requirements.

56. 98.232 (a) (7); 98.233 (c) (1); 98.233 (d) (7); 98.234 Flares:
API Comments: It is not clear where the 95% flare destruction efficiency for non-assisted flares was obtained by EPA for inclusion in this rule. The only documentation seems to be an "assumed" value in the technical support document for Subpart W. As EPA knows, the "standard" flare efficiency assumption for flares with designed mixing tips/burners (which the majority of the facilities that will be subject to the proposed rule will have) is 98% rather than 95%. API would also like to point out that more recent studies than EPA's 1983 work regarding flare destruction efficiency have been published and broadly confirm the 98% plus destruction efficiency from designed flares. For example see the publication titled "Reaction Efficiency of Industrial Flares" available from Natural Resources Canada at the following URL: http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/clean_fossils_fuels/industrial_combustion_processes/consortium/publications_presentations/reaction_efficiency.html. As this study confirms, a much better assumption would be

that designed flares achieve 98% destruction efficiency rather than the 95% assumed by EPA in this rule. API requests that EPA modify the default flare destruction efficiency in the rule to 98%. API would also like to point out that the "International Flare Consortium" has been working for several years on an updated flaring efficiency study across a wide range of gas fluid types, flare tip types, and wind shear conditions. Publication later this year is expected and when published API urges EPA to incorporate this latest information into the proposed rule.

It is not entirely clear what *"measurement"* is required for flares in 98.234 (j). The requirement to *"(i)Insert flow velocity measuring device (such as hot wire anemometer or pitot tube) directly upstream of the flare stack or compressor wet seal degassing vent to determine the velocity of gas sent to flare or vent"* is not very descriptive nor helpful and is problematic for several reasons.

First, the majority of flares in the Oil and Natural Gas industry, particularly at the facilities which will be subject to this rule, are "emergency use" flares which are intended for upset and blowdown use rather than continuous disposal use – natural gas is one of the primary products of this sector. Emissions from these flares are comprised of continuous pilot fuel, continuous purge gas (small volume continuous gas flow through the flare header to prevent air ingress into the flare header during a rapid temperature change), and emissions from flaring on upset or blowdown. With very low continuous flow/velocity in a large flare header, inserting a flow measuring device such as a hot wire anemometer or pitot tube will likely not record any flow. As the requirement for measurement of velocity seems to be annual it is not likely that flare flow would ever be indicated by this method.

Second, if the flare was in active use during an upset or blowdown event, it would be incredibly dangerous to get close enough to the stack to insert a flow velocity measuring device (such as hot wire anemometer or pitot tube) directly upstream of the flare stack – particularly if this stack were located on a flare boom several hundred feet above the deck on an offshore platform.

Third, the advisability of inserting a hot wire anemometer in a flare header filled with highly combustible gas does not seem like a wise method to require. If there does happen to be any air present this could have very unpleasant or deadly consequences.

API requests that EPA replace the current measurement requirement with the following options:

- Determine the amount of purge gas used in the flare using the appropriate engineering calculations. Pre-calculate the blowdown volume of each system (as described in 98.233 (d) (5) for blowdown stacks) which may be routed to flare during an upset or blowdown event. Log the number of events and what systems were depressured to flare. Calculate the volume based on these parameters and then use the known gas compositions to calculate the CO_2 and CH_4 emissions from the flare.
- Use existing or new permanently installed flare metering devices to record the flow to the flare on a continuous basis. Couple this with engineering knowledge and calculations of the "average" gas composition which goes to flare at any particular facility over the course of a year. If the permanently installed meter cannot "see" the low flow purge then add this volume and calculated GHG's to the total.

57. 98.232 (a) (6); 98.233 (c) (3); 98.233 (d) (9); 98.234 Compressor wet seal degassing vents: API requests that EPA explain the difference between compressor wet seal degassing vents and centrifugal compressor wet seals from an emissions perspective. These terms are not defined in the proposed rule and the distinction between them from an emissions perspective is not clear as the emissions from a centrifugal compressor wet seal occurs through the compressor wet seal degassing vent (actually the seal oil degassing tank vent).

The measurement prescribed in 98.234 (j) is not appropriate for this source type. Seal oil degassing tanks are typically vented through solid piping at slightly above roof elevation outside of the building housing the compressor and seal oil unit. Because they are solid piped, inserting a hotwire anemometer or pitot tube in the pipe directly upstream of the vent is not possible without shutting down the unit and installing ports. Additionally, it again does not seem prudent or safe to use a hot wire anemometer to measure velocity from a low flow vent directly upstream of its exhaust to atmosphere.

API requests that EPA replace the current measurement requirement with the following options:

- Allow the use of alternative measurement devices, such as turbine meters, orifice meters, or vane anemometers for either permanent installation and periodic measurement or periodic measurement to measure the flow velocity.
- Exempt any seal oil degassing vents that are routed to either vapor recovery and/or fuel use from the requirements to monitor and report emissions under the rule.

58. §98.233 and §98.234. EPA proposes that the fugitive emissions from some sources be detected using optical or analyzer methods and then quantified by direct measurement using either high volume samplers, calibrated bags, or meters. This approach is onerous and costly and offers little additional benefit over the use of component counts (physical count or engineering estimate) and emission factors.

In addition, the measurement approaches required by the proposed rule are not practical for the complicated emission sources found in industry. For example, calibrated bags cannot be applied to compressor seals. Compressor seals are not simple fittings such as flanges that exist on external pipes. The construction of compressors varies; due to differing construction, emissions from compressor seals may or may not be routed to a discrete location.

Default emission factors are acceptable for estimating fugitive emissions for MMS GOADS program and for onshore facility CAA compliance/permitting. This method of obtaining the emissions data will ensure consistency with GOADS data, avoid duplicative massive data submittals to different Agencies, and reduce the impact on individual offshore platform operators.

59. API recommends a de minimis provision for sources covered under Subpart W. The provision would allow a simplified method or limited studies to demonstrate de minimis. Sources determined to be inconsequential would also not have to comply with QA/QC, reporting, and monitoring requirements. The sources could be revisited every few years to confirm that the methods are still applicable. Some potential de minimis emission sources include:

- Low and no bleed/pilot operated pneumatic controllers - these types of pneumatic instrumentation use and emit almost no gas. Gas is emitted only when the controller removes the power signal and bleeds the pressure on the pneumatic valve actuator to allow it to close.
- Pneumatic valve actuators - these are actually the same as the first bullet for pilot operated controllers and essentially zero for continuous bleed controllers that are assumed to be "bleeding" 24 hours per day.
- Tanks with very low CH_4 content - These would include condensate/oil tanks downstream of the tank where the oil/condensate first "flashes" and equilibrates to atmospheric pressure. This would also include tanks where the oil had been stabilized or treated in a heater-treater upstream of the tank.
- Normal (component) fugitives from process streams where the CH_4 content is below 10%. This includes valves, connectors, open ended lines (not blowdown stacks), pump seals, etc
- Miscellaneous heaters with an aggregate heat input capacity of less than 2 MMBtu/hr.
- Tanks or dehydrators with VRU control installed.
- Non-pneumatic pump seal leaks where the fluid being pumped (close to 100%) is less than 10% CH_4 or 25% CO_2 (anticipating future CO_2 dense phase pumping).
- Emission sources associated with the handling of stabilized crude.

Specific de minimis sources would be left to the reporter to determine based on characteristics of their facility.

The API Compendium also notes the following non-GHG sources which may be associated with oil and natural gas operations: Chemical Storage Tanks, Glycol Storage Tanks, Mud Cuttings Roll-Off Bins, Naphtha Storage Tanks, Slop Oil Tanks, Sumps, and Water Blowdown Tanks. API members have concluded that there are no GHG emissions from these sources, and therefore they should not be included in a GHG inventory.

60. Subpart W - Fugitive Emissions Definition

API Comments: API does not support the EPA definition of fugitive emissions in Subpart W. As noted in a previous comment, the definition is not appropriate and results in requirements for monitoring, measurement, and reporting that are overly burdensome, costly, inappropriate, and unnecessary. The following comments address API's specific concerns regarding this issue:

60.1. (a) Subpart W – Leak Detection and Quantification Requirements

API does not support EPA's requirements for leak detection and subsequent quantification as detailed in Subpart W. API requests that EPA replace these requirements with a component count (based on physical count or engineering estimate) and emission factor approach for "normally defined" (see comment directly above) fugitives. API further requests that EPA adopt different requirements, many of which are detailed in API's Subpart W section of these comments, for "non-traditional" fugitive sources.

60.2. Leak Detection and Quantification for Traditional Fugitive Sources

EPA proposes that the fugitive emissions from some sources be detected using optical or analyzer methods and then quantified by direct measurement using high volume samplers, calibrated bags, or meters. This approach is onerous, costly, offers little additional benefit over the use of component counts (physical count or engineering estimate) and emission factors, and is not justified in either the Technical Support Document (TSD) or Preamble discussions for Subpart W.

EPA justifies their requirements for annual leak detection and subsequent quantification of identified leaks with the following statements in the Preamble and Technical Support Document:

> "*There have been no subsequent comparable studies published to replace or revise the fugitive emissions estimates available from this study*." (rule Preamble)
>
> "*There are several estimates of emissions factors for emissions sources that do not correctly reflect the operational practices of today*." (Subpart W TSD – page 18)

API does not believe these statements are accurate and should not be the justification for the burdensome requirements in the proposed rule.

According to EPA's technical support document for Subpart W, EPA relied solely on the GRI/EPA study of 1992 (published in 1996) and did not include later studies which are more current and relevant to this rule making. In particular, EPA did not include the EPA sponsored Phase I (USEPA Grant No: 827754-01-0) and Phase II (EPA Grant No. not available; Title: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites) studies which measured fugitive emissions at 9 gas processing facilities and 7 compressor stations (in excess of 207,000 components). EPA also did not include the EPA, PRCI, GRI transmission station study (EPA Grant No. not available; Title: Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations) which evaluated in excess of 35,000 components in their analysis of available fugitive emission studies and data available.

In the TSD, EPA then lists 5 specific source types where they feel the uncertainty is large – these being "Condensate and oil storage tanks"; "Natural gas well workovers"; "Natural gas well completions"; "Natural gas well blowdowns"; and Flares". It is noted that of these specifically listed source types only two of them are within the scope of the currently proposed rule and many condensate tanks at gas processing facilities and offshore production facilities have emission controls (VRU's and/or thermal destruction) installed. Also in many gas processing and offshore production facilities permanent flare velocity and/or flow meters are installed (please note that this is not uniform throughout the industry). These facts eliminate much of EPA's expressed concern regarding the quality of current emission estimates.

By requiring the direct measurement of fugitive emissions and not providing any alternative means to inventory these small emissions, EPA has imposed a disproportionate and inappropriate burden on the oil and natural gas systems industry which is not based on analysis of information and studies which were conducted with EPA's support and involvement. In view of EPA's exclusion of the studies noted above and potentially other studies which remain to be identified, this burden is not justified and EPA's analysis is deficient.

EPA currently has an active study underway with the University of Texas leading to improve the fugitive emission factors for the Oil and Gas industry which is scheduled for completion in about 3 years. Industry is actively participating in and supporting this work – as they have the prior studies.

Given the exclusion of relevant information in the decision basis and in view of the current study underway, EPA's requirements for leak detection and quantification in Subpart W are not warranted and impose substantial costs on the industry. As an alternative to the prescribed annual leak detection and subsequent quantification of identified leaking sources, EPA should incorporate the studies noted above and allow fugitive emission estimation and reporting based on component counts (either physical or engineering estimated) and emission factors derived from incorporation of more current and relevant studies. For example, the combined "fugitive factors" from the Phase I and Phase II studies as compared to the information EPA considered in crafting the rule are shown in the table directly below:

Comparison of average THC emission factors derived from data collected in both Phase I and Phase II studies to other published values.

Source	U.S. EPA[1]	U.S EPA Gas Facilities[2]	Average of Phase I and II
Connectors	2.0E-04	3.05E-04	2.76E-03
Block Valves	4.5E-04	3.40E-03	6.24E-03
Control Valves	4.5E-04	N/A	4.29E-02
PRVs	8.8E-03	2.24E-03	3.39E-02
Pressure Regulators	8.8E-03	N/A	1.19E-02
Orifice Meters	8.8E-03	N/A	3.19E-03
Crank Case Vents	N/A	N/A	5.02E-01
OELs	2.0E-03	9.02E-02	1.45E-01
Compressor Seals[4]	8.8E-03	1.17	6.86E-01

1 Source: U.S. EPA 1995. Protocol for Equipment Leak Emission Estimates

2 Source: U.S. EPA and GRI 1996. Methane Emissions from the Natural Gas Industry. Volume 8: Equipment Leaks

60.3. Leak Detection and Quantification Cost

It also appears that EPA significantly underestimated the cost of the required leak detection and quantification although, due to the short comment period allowed for the rule, detailed analysis of cost estimates for this work have not been possible.

However, one of the API member companies did furnish cost information from a leading leak detection contractor for just the detection portion of the requirements applied to a Gulf of Mexico (GoM) platform. The following estimate of costs was prepared to perform an IR camera survey of a single platform. The estimate is based on three platform surveys conducted by one operator in the Gulf of Mexico.

Item	Estimated Cost
IR technicians	\$8,000
Engineering	\$2,000
Helicopter flights (3 person)	\$1,500
Room and board offshore	\$150 (one night, but see flight delay costs)
Offshore work sponsor	\$250
Average weather/flight delay	\$1500
Total estimated IR survey cost per platform	**\$13,400**

As this estimate illustrates, the costs to simply perform leak detection using IR technology is not trivial. When the costs of managing bag or volume samplers for emissions quantification are also considered, the fugitive measurement costs quickly grow for a single platform. When coupled with the most recent count of active platforms in the Gulf of Mexico of 3,738 (according to the information at http://www.gomr.mms.gov/homepg/fastfacts/ WaterDepth/WaterDepth.html), the fugitive monitoring burden including pump and compressor seals) for the entire Gulf of Mexico platform population will be very costly and time consuming and is not commensurate with the relative insignificance of the CO_2e footprint involved.

API is conducting a survey of elements related to EPA's cost assumptions for the reporting rule. API will provide the results of the survey in a separate submittal.

60.4. Exclusion of "Low and No" CH_4 Content Fluid Systems

API requests that EPA exclude components and equipment in "low and/or no" CH_4 content service from the requirements of Subpart W. Regardless of the direction that EPA takes regarding fugitive leak determination and quantification, process streams with less than 10% CH_4 should be excluded from component leak detection and quantification or inclusion in a component count and factor based approach. Once oil/condensate has been stabilized or "flashed" to atmospheric pressure, storage tanks receiving such fluids should be excluded from consideration for CH_4 emissions. Excluding these insignificant sources of CH_4 emissions would greatly reduce the potential burden of the requirements in the proposed rule.

60.5. Exclusion of Small Size Components

API requests that EPA exclude components and equipment in systems where the ID of the piping is less than 1" from the requirements of Subpart W. As proposed, the monitoring provisions have no size thresholds for fugitive components subject to fugitive detection, quantification, and reporting. Natural gas processing and compression facilities have large numbers of small connectors, pneumatic actuators, etc. many of which are associated with ¼ inch control system tubing. Absent any size threshold for such equipment, all sizes of fugitive components would be subject to the rule. These emission sources are small and inconsequential. Tracking and quantifying emissions from such small emissions points is costly, time consuming, and provides little benefit."

60.6. Alternative Measurement Methodologies

If EPA persists in requiring direct measurement quantification of fugitive CH_4, additional flexibility must be provided beyond what is included in proposed § 98.234. Such flexibility should allow use of engineering estimation techniques and/or measurement methods not currently contemplated or included in the rulemaking. Although our examples below focus on the measurement of traditional fugitive sources (component leaks), the need for flexibility and allowance for additional methods applies in principal to methodologies for all sources listed in § 98.232.

For facilities where the majority of the facility process/piping components are contained in enclosed modules or buildings (e.g. North Slope Alaska) EPA should include a methodology based on HVAC flow and CH_4 content in the exhaust gas. Many such modules/buildings have highly-engineered HVAC systems providing precise air exchanges. HVAC air exchange information combined with data regarding exhaust air CH_4 content would provide a robust means of determining CH_4 emissions.

As an adjunct to the above described technique, reductions in detection limits of CH_4 emissions from enclosed processing modules/buildings HVAC systems could be accomplished with tracer gas ratio analysis. As API understands, there is not currently a well-defined protocol for performing such tracer studies, but the science is well established, and development of a method for enclosed processes would not require extraordinary effort.

EPA should also enable additional methodologies such as ultrasonic techniques.

60.7. Offshore Petroleum and Natural Gas Production Facility Specific Comments

Default emission factors are acceptable for estimating fugitive emissions for the MMS GOADS program and for onshore facility CAA compliance/permitting. This method of obtaining the emissions data will ensure consistency with GOADS data, avoid duplicative massive data submittals to different Agencies, and reduce the impact on individual offshore platform operators.

Unlike onshore facilities, offshore platforms have legal limits on POB (allowed number for Person on Board set by USCG). Typically POB are at the maximum allowed by personnel required for operations, legal testing (MMS/USCG), and other maintenance that must be done to ensure the safety of the facility along with personnel needed to complete required maintenance work (painting and blasting, inspections, etc.) and annual monitoring. In the Gulf of Mexico, facilities typically lose 1 to 5 months at many platforms due to shutdowns during hurricane season. Finally, if platforms are damaged, POBs are quickly consumed by inspection and repair crews. While, flotels can be used to allow increased personnel onboard, costs are very high and carry significant safety risks. Therefore, it will be difficult to accommodate the personnel needed to conduct the fugitive emissions monitoring and measurement.

Contractors may not be available to support the huge monitoring demand that will occur in 2010. Unlike, perhaps, onshore facilities, monitoring expertise will not be maintained at offshore facilities. Thousands of offshore facilities will be competing for contractors (along with onshore facilities) for monitoring expertise. Additionally, as of April 15, 2009, all personnel visiting offshore facilities must have a special identification card issued by Homeland Security (Transportation Worker ID Card or TWIC). This TWIC system has been plagued with delays and problems and getting a card can take many months.

Due to the relatively small contribution of CH_4 emissions, it is suggested that only combustion source emissions be reported for offshore platforms, or if fugitive emissions are reported, that emissions factors be used to calculate fugitive emissions and a de minimis reporting threshold be established for fugitive emissions. The following example illustrates this relationship between combustion and other emissions for an average of 14 platforms in Gulf of Mexico. This is based on emissions data gathered in 1st quarter 2008 emissions (representative of non-hurricane impacted operations).

Emission Source	CO_2e tonnes *	% of Total
All Combustion Sources (CH_4 + CO_2)	223156	>99
All fugitive sources (CH_4)	865	< 1
Total	224021	100

*Data per industry accepted emission factors, typical component counts and fuel metering.

Additionally, there is fugitive emission (gas) detection at several facility locations for purposes of Fire & Explosion/Process Safety. The more modern platforms have them everywhere, pointed at the most susceptible equipment, and rarely do they detect any measurable CH_4 emissions. When they do, the leak source is identified, the area/platform is shut-down and the leak is repaired

Further, as EPA states in the Preamble, offshore platforms contribute only 4% of total the total CO_2e's for the U.S. Based on the above data, the contribution for fugitive sources to total U.S. CO_2e's from all offshore facilities would be on the order of 0.04% (4% × 0.01). The prescriptive monitoring and QA requirements in the proposal for this level of emissions are not justified to meet EPA's stated intended purpose of the rule which is to support analysis of future policy decisions in an efficient and cost effective manner.

60.8. Miscellaneous Considerations and Comments

The quantification requirements in §98.234 are problematic. The three options allowed are a high volume sampler, bag samples, or meters. The order of measurement techniques preference prescribed in the rule may not be universally appropriate depending on equipment configuration and leak rate. There may also be cases where none of the three methods adequately capture the emissions, or where additional methods provide equivalent results. For example, acoustic methods are often superior to infrared methods. The final rule should allow technicians to use judgment as to which measurement instrument is most appropriate for the component and measurement situation. In addition, engineering estimations/calculations should be allowed as an alternative approach.

The measurement approaches required by the proposed rule are not practical for the complicated emission sources found in industry. For example, calibrated bags cannot be applied to compressor seals. Compressor seals are not simple fittings such as flanges that exist on external pipes. The construction of compressors varies; due to differing manufacturers, requirements, and construction - emissions from compressor seals may or may not be routed to a discrete location.

API also requests that EPA also add a provision that allows an operator to designate a detected leak as "unable to quantify" after making a good faith effort to quantify emissions. The scope and scale of leak detection and quantification contemplated in this rule is unprecedented and it is highly likely that leaks will be identified that, despite best efforts, simply cannot be accurately quantified – regardless of effort. When this occurs, reporters must have an available option to explain why a detected leak cannot be quantified and then designate it as "unable to quantify".

Although §98.234(k) does allow relief from including sources not safely accessible within arm's reach, this exclusion is specific to components and does not include the other Subpart W source types. API requests that this exclusion be extended to all Subpart W sources which cannot be safely accessed, within arms reach or otherwise. For example, moving or reciprocating parts may never be safe to access unless shut down.

60.9. Leak Detection for Non-Traditional Fugitive Sources

As stated above, API does not support EPA's approach to these sources.   However, should EPA retain these requirements, API recommends removing the requirement for annual leak detection from the following sources (which API does not consider fugitive sources) listed in 98.232 (a):

- (1)Acid gas removal (AGR) vent stacks; (6)Compressor wet seal degassing vents; (7)Dehydrator vent stacks; (8)Flare stacks; (22) Storage tanks: Unless equipped with control or vapor recovery, these sources are designed to have emissions at all times unless shut-down and there is nothing to be gained by doing an annual leak detection; and:
- (11)Natural gas driven pneumatic pumps; (12)Natural gas driven pneumatic manual valve actuator devices; (13) Natural gas driven pneumatic valve bleed devices: These sources are designed to have emissions while operating and it is sufficient to determine if they are operating without doing a leak detection using an optical or analyzer device.

60.10. Fugitive Emissions Detection and Measurement "Standards"

Sections 98.233 & 98.234: These sections specify the estimation and measurement techniques for sources listed in section 98.232. "These techniques and protocols have not benefited from the rigorous testing and expert review required by major standard-setting organizations such as ASTM, ASME, API, and the American Gas Association (AGA). As a result, the proposed rule creates a risk that the various testing methods in the proposed 40 CFR § 98.234 will not give accurate results or be applied consistently. Indeed, many of the protocols in the proposed rule are not adequately specified and could generate unreliable data. For example:

- In 98.234(d)(2), (4), the infrared detection protocol requires the operator to inspect the emissions source from "*multiple angles*" without "*visual* *obstructions*" and in "*favorable conditions*," without elaborating on the correct procedure for doing so.

- In 98.234(f), the high volume sampler measurement protocol requires that the equipment be operated by a "*trained technician*" who is "*conversant*" with sampling techniques, but does not specify what operating procedures and measurement methodologies the technician would be expected to know. In addition, the protocol directs the technician to use "*anti-static wraps or other aids*" if the high volume sampler is not able to completely capture all emissions from the source, but does not specify how such leakage is to be detected or how these aids are to be used.
- In 98.234(g)(5), the calibrated bag protocol states that the operator must "*obtain consistent results*" when measuring the amount of time required to fill the bag, but does not provide a benchmark for consistency.

EPA's approach will also hinder the adoption of more advanced measurement techniques, because a new rulemaking will be required if EPA ever chooses to revise the protocols in the proposed rule.

A better approach would be for EPA to engage industry leaders and at least one of the major standard-setting organizations to develop consensus protocols for detection and direct measurement of fugitive emissions. The agency has wisely chosen to defer to such consensus standards for CEMS in Subpart C portion of the Proposed Rule, and should seek to do the same in Subpart W. Consensus standards would provide assurance that the direct measurement protocols required in the Rule reflect the state of the art and are being applied in a consistent matter that is uniformly understood within the industry. This would also justify deferring the effective date of the final rule.

These methods would not have to be written directly into the final rule, but could instead be provided in a guidance document that could be easily revised in step with field experience and advances in measurement technology. API is willing to be a constructive partner in developing such standards.

61. The definition of 'Offshore petroleum and natural gas production facilities' states in part that the *"facilities under consideration are located in both State administered waters and Mineral Management Services administered Federal waters."* The platforms in the Western Gulf of Mexico should be excluded from the reporting rule because the MMS has jurisdiction for air emissions from facilities on the Outer Continental Shelf.

Under the Outer Continental Shelf Lands Act (OCSLA), the Department of Interior (DOI) has the authority to regulate air emissions on the OCS. U.S.C. §1334. In *California v. Kleppe*, 604 F.2d 1187 (9th Cir. 1979), the court held that the OCSLA's specific grant of jurisdiction to DOI precluded the application of Prevention of Significant Deterioration regulations to E&P facilities on the Outer Continental Shelf (OCS). In so ruling, the court specifically rejected EPA's argument that dual jurisdiction over air pollution on the OCS existed between EPA and DOI.

After *Kleppe* the 1990 Clear Air Act Amendments (CAA) established the authority of EPA to regulate air pollution on the OCS from oil and gas exploration and production facilities (referred to as "OCS sources"), but as to the Gulf of Mexico limited EPA's air pollution jurisdiction over OCS sources to the area of the Gulf of Mexico east of longitude 87 degrees and 30 minutes and confirmed DOI's air pollution jurisdiction to the area of the Gulf of Mexico west of longitude 87 degrees and 30 minutes (Western Gulf).

> **Air pollution from Outer Continental Shelf activities, 42 U.S.C. §7627**
> **(a)(1) Applicable requirements for certain areas**
> Not later than 12 months after November 15, 1990, following consultation with the Secretary of the Interior and the Commandant of the United States Coast Guard, the Administrator, by rule, shall establish requirements to control air pollution from Outer Continental Shelf sources located offshore of the States along the Pacific, Arctic and Atlantic Coasts, and along the United States Gulf Coast off the State of Florida eastward of longitude 87 degrees and 30 minutes ("OCS sources") to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of part C of subchapter I of this chapter. For such sources located within 25 miles of the seaward boundary of such States, such requirements shall be the same as would be applicable if the source were located in the corresponding onshore area, and shall include, but not be limited to, State and local requirements for emission controls, emission limitations, offsets, permitting, monitoring, testing, and reporting … The authority of this subsection shall supersede section 5(a)(8) of the Outer Continental Shelf Lands Act [43 U.S.C.A. § 1334(a)(8)] but shall not repeal or modify any other Federal, State, or local authorities with respect to air quality…
>
> **(b) Requirements for other offshore areas**
> For portions of the United States Gulf Coast Outer Continental Shelf that are adjacent to the States not covered by subsection (a) of this section which are Texas, Louisiana, Mississippi, and Alabama, the Secretary shall consult with the Administrator to assure coordination of air pollution control regulation for Outer Continental Shelf emissions and emissions in adjacent onshore areas. Concurrently with this obligation, the Secretary shall complete within 3 years of November 15, 1990, a research study examining the impacts of emissions from Outer Continental Shelf activities in such areas that fail to meet the national ambient air quality standards for either ozone or nitrogen dioxide. Based on the results of this study, the Secretary shall consult with the Administrator and determine if any additional actions are necessary.

In the proposed rule, EPA has expressly stated that the CAA is the source of its authority for the proposed rule. There is no authority under the CAA for the collection of information with respect to geographic areas or industry segments over which EPA has no jurisdiction. *See* 42 U.S.C. §7414(a) (enumerating authorized purposes for EPA's seeking information from the regulated community). Instead of EPA jurisdiction over OCS sources in the Western Gulf, under the CAA, the Secretary of DOI is merely required to consult with the Administrator of the EPA with respect to OCS emissions with regards to the Western Gulf, not vice versa.

Congress has recognized that the Western Gulf of Mexico is a unique national resource. In order to promote and regulate the expeditious and orderly development of this resource, Congress made a conscious decision to place the regulation of air emissions from OCS sources with DOI, an agency that has specialized expertise with regard to exploration and production activities and their effect on both the OCS and onshore environments. Under OCSLA, Congress has chosen DOI as the lead and exclusive agency for all aspects of air emissions in the Western Gulf. EPA's proposed rule undermines Congress' delegation of this authority to DOI.

Further, EPA's proposal is unfair, inefficient and will be unduly burdensome on this industry segment. The collection and submittal of data for OCS sources in the Western Gulf would impose substantial burden and expense on energy companies, and would provide data to EPA that could not be utilized for the development of emission or other regulatory standards for such sources. Operators in the Western Gulf are already subject to a similar information collection framework through the Minerals Management Service GOADS system. Rather than subjecting the Western Gulf exploration and production industry to two reporting frameworks, EPA should coordinate to obtain the desired information from DOI. There are no other geographic areas or industries that would be required to report the same information under two separate and independent reporting frameworks. The CAA does not contemplate parallel or concurrent jurisdiction.

Finally, EPA cannot justify applying this proposed rule to the Western Gulf by stating that it is under a directive to collect information from all industry segments. The general statement that emissions from all segments should be reviewed cannot be fairly interpreted as an expansion of jurisdiction where there previously was none. Nor can EPA justify this proposed rule by stating that "information collection" is not "regulation." This issue was addressed in the *Williams Companies v. FERC*, 345 F.3d 91 (D.C. Cir. 2003). In *Williams*, the court found that the FERC could not require companies to submit certain information relating to pipeline transportation rates on OCS pipelines because Congress gave DOI (through OCSLA) authority to regulate open and non-discriminatory access to OCS pipelines.

As applied to OCS sources in the Western Gulf, the proposed rule is beyond EPA authority, violates both the CAA and OCSLA (and possibly other federal statutes such as the Administrative Procedures Act, the Paperwork Reduction Act, etc.), and is unfair, overly burdensome and inefficient. For these reasons, the Western Gulf should be excluded from the proposed rule.

62. §98.233(b)(7)(i). The default flare combustion efficiency assumed in the rule is 95% for non-steam aspirated flares and 98% for steam aspirated or air injected flares, if manufacturer data is not available. API recommends applying a minimum 98% combustion efficiency for flares based on the following considerations taken from the API Compendium:

> Unless regulatory requirements dictate otherwise, general industry practice relies on the widely accepted AP-42 document which states: "properly operated flares achieve at least 98 percent combustion efficiency" (EPA, AP-42 Section 13.5.2, September 1991, Reformatted January 1995), where 98% efficiency is consistent with the performance of other control devices. However, increased interest in GHG and air toxic emissions has prompted studies to more accurately characterize emissions from oil and gas industry flares (Ozumba, 2000; Strosher, 1996). Findings from these studies indicate a minimum of 98% combustion efficiency, with much higher efficiencies (≥ 99.5%) measured in most situations, and very little, if any, detectable CH_4.

63. §98.233(d). The term "volumetric" should be added to the definition for the variable $E_{s,n}$ in Equations W-1 through W-3, to the definition for the variable $E_{a,n}$ in Equation W-4, and to the definition for the variable $E_{a,h}$ in Eq. W-7. Although it is implied (and follow-on calculations

result in volumetric emissions), it is never stated that the results of these calculations are volumetric emissions.

64. §98.233(d)(7)(iii). The following items need to be revised for Eq. W-5:

- Variable definitions need to be provided for condition "a" and "i" (e.g. a = actual; i = gas analysis);
- Concentrations (variables X_i and Y_j) should be specified as "molar";
- A summation needs to be added for the multiplication of the factors "$Y_j xR_{j,i}$" (shown below as "$Y_{j,i}xR_j$").
- A summation over time period "n" needs to be added to account for the fact that there will be multiple gas analyses during the reporting year.

In addition to the four items noted above, Eq. W-5 should be split in two – separately identifying the calculation approaches for CO_2 and CH_4. As currently presented, Eq. W-5 is confusing and has caused much debate among the industry. Instead of the one combined equation, it is recommended that two equations be presented as follows. The equation for CO_2 provided below also removes the adjustment for flare efficiency from the first equation term. CO_2 already present in the gas stream is not impacted by flare efficiency; all of the CO2 present in the flared stream is emitted as CO_2.

$$\text{Eq. W-5a:}\quad E_{CO2,a,i} = \sum_{1}^{N}\left(V_a \times X_{CO2} + \eta \times V_a \times \sum_{1}^{i}\left[Y_{j,i} \times R_j \right]\right)$$

$$\text{Eq. W-5b:}\quad E_{CH4,a,i} = \sum_{1}^{N}\left(V_a \times (1\text{-}\eta) \times X_{CH4} \right)$$

Variable definitions for the above equations are taken from the proposed definitions, except where modified as shown in italics. Where:

$E_{CO2,a,i}$ = Annual *CO_2 volumetric emissions* from flare stack *at actual conditions for gas analysis i.*

$E_{CH4,a,i}$ = Annual *CH_4 volumetric emissions* from flare stack *at actual conditions for gas analysis i.*

V_a = Volume of natural gas sent to flare stack at *actual conditions* determined from § 98.234(j)(1).

H = Percent of natural gas combusted by flare (default is 95 percent for non- steam aspirated flares and 98 percent for steam aspirated or air injected flares).

X_{CO2} = *Molar* concentration of *CO_2* in the flare gas determined from § 98.234(j)(1).

X_{CH4} = *Molar* concentration of *CH_4* in the flare gas determined from § 98.234(j)(1).

$Y_{j,i}$ = Concentration of natural gas hydrocarbon constituents j (such as CH_4, ethane, propane, butane, and pentanes plus) *for gas analysis i.*

R_j = Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

N = Number of required gas analyses during reporting year.

65. §98.233(d)(7) and §98.233(e). For Eqs. W-6 and W-9, definitions for Ts and Ps should be added to avoid confusion as to which values should be used.

66. §98.233(e). Clarification should be added to §98.233(e), which currently states *"Calculate natural gas volumetric fugitive […]"*, as this equation is also used to calculate hydrocarbon vapor volumetric fugitive emissions per §98.233(d)(8).

67. §98.233(g). Standard conditions are defined in §98.6 as 60 °F and 14.7 psia. This is consistent with the densities identified in Equation W-11 for calculating CO_2 and CH_4 mass emissions corresponding to standard conditions of 60 °F and 14.7psia. However, the molar volume conversion of 849.5 scf/kgmole presented throughout the subsection equates to 68 °F and 14.7 psia. The correct molar volume conversion should be 836.2 scf/kgmole.

68. §98.233(g). Eq. W-11 provides specific densities of GHG_i in units of kg/m^3. This is the first equation in subsection W to specify volumetric units of m^3. To avoid confusion and miscalculation of emissions all prior equations in this subsection should specify volumetric units of m^3 or the densities associated with Eq. W-11 should be provided in a range of units (e.g. kg/m^3, kg/scf).

69. Pg 16678, §98.234(b)(11): As proposed, the monitoring provisions have no size thresholds for fugitive components. Natural gas processing and compression facilities have many small connectors, pneumatic actuators, etc. many of which are associated with ¼ inch control system tubing. Without any size threshold for such equipment all size of fugitive components would be subject to the rule. These emissions sources are small and inconsequential. Tracking and quantifying emissions from such small emissions points is costly, time consuming, and provides little benefit."

70. §98.234(k) does allow relief from including sources not safely accessible within arm's reach. API requests an exclusion provision for components that are within arm's reach but are not safe (such as reciprocating parts). Actually, the only relief is for "components" which are out of reach and this does not include valves, compressor seals, etc.

71. Clarification of reporting obligations for the 24 listed source types should be provided. There is duplication of emission sources within the list that could cause confusion or an agency finding that emissions are improperly characterized. For example, "transmission station fugitive emissions" is an all encompassing descriptor and broadly defined in §98.6. Many of the other listed sources (e.g., multiple types of seals, rod packing, compressor fugitives, pneumatics, etc.) are also listed sources and there is redundancy and overlap within these categories – and all fit within the category of "transmission station fugitives" as well as other broad source categories. If these 24 source types (or a revised list) are retained in the rule, EPA should clarify that operators are not subject to reporting scrutiny or compliance questions regarding how data is classified in the report as long as the information is complete and relevant sources are included in the report – i.e., "misclassification" should not be considered a reporting error or deviation.

Subpart X - Petrochemical Production (98.240)

72. §98.242. EPA's rule focuses on CO_2 emissions from petrochemical production, with no mention of CH_4 or N_2O emission. This is contrary to the EPA *Inventory of Greenhouse Gas Emissions and Sinks* which estimates CH_4 emission from carbon black, ethylene, ethylene dichloride, and methanol; and N_2O emissions from nitric acid and adipic acid production. [The Compendium cites emission factors for CH_4 and N_2O from the EPA national inventory.]

73. §98.243(a)(2). Two sets of brackets should be added to Eq. X-2 to identify the proper use of the summations. Two sets of brackets should also be added to Eq. X-3 to identify the proper use of the summations.

74. "Section 98.243 requires process-based GHG emissions to be determined based on either a continuous emission monitoring system (CEM) or by conducting a weekly mass balance for each petrochemical process unit. As discussed in the Technical Support Document of the Petrochemical Production Sector, *"All of the emissions associated with the ethylene process are from combustion units."* This statement is consistent with EPA's determination during the Ethylene MACT rulemaking that ethylene plants do not have continuous process vents. Therefore, the emissions quantification methodology provided in §98.243 is not appropriate for ethylene production plants. Alternatively, subpart C would provide the appropriate methodologies for estimating GHG emissions from ethylene production plants. The most accurate means of determining ethylene unit GHG emissions is to base the determination on fuel combustion, which is the methodology used currently by most ethylene units. These units typically do not have CEMS, and the proposed alternative, a weekly mass balance requirement, is onerous and most likely would be less accurate than a fuel combustion methodology.

75. §98.244(a)(2). Reporters that are using the mass balance methodology are required to measure the volume of each gaseous and liquid feedstock and product continuously using a flow meter. Flow meters may not exist on all gaseous and liquid feedstocks and products. A turnaround may be required to install the flow meters. The turnaround cycle for units varies between 2 to 5 years. EPA should specify: (1) the reporter must install the flow meters during the next scheduled turnaround after January 1, 2010; and (2) until such time as a flow meter is installed, the reporter may estimate the flow and document the method used for estimating the flow in the records required to be maintained under §98.247.

76. §98.244(a)(3). Reporters are required to collect a sample of each feedstock and product for each process unit at least once per week to determine the carbon content. The composition of the feedstock and product do not vary significantly because feedstocks and products must meet strict specifications standards. Specifications for various impurities are in the ppm range and not the percent range. Thus, less frequent sampling is warranted. API requests a provision to allow the reporter to determine a sampling frequency that is consistent with the variability of the stream.

Subpart Y - Petroleum Refineries (98.250)

a. EPA Requested Feedback

77. *"The Agency requests comment on the feasibility of allowing smaller emission sources at the refinery to employ less certain (Option 1) methods as a way to reduce the costs and burden of measurement and verification under this proposed rule." (p. 16541)*
API comments: API supports the tailoring of emission estimation methods to fit the relative contribution of an emission source to the overall inventory. In addition, API supports including a de minimis condition.

The cost burden goes beyond just the measurement and verification. QA/QC, reporting, and monitoring requirements should also be relaxed for insignificant emission sources. API requests a provision that allows a simplified method or limited studies to demonstrate de minimis. Sources determined to be inconsequential would also not have to comply with QA/QC, reporting, and monitoring requirements. The sources could be revisited every few years to confirm that the methods are still applicable.

For example, under AB32: The operator may elect to designate as de minimis one or more sources that collectively produce no more than 3 percent of the facility's total CO_2 equivalent emissions. The operator may estimate emissions for these de minimis sources using alternative methods of the operator's choosing, subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated and estimated do not exceed the applicable de minimis limits.

Some potential de minimis emission sources from refining include: fugitive emissions, tanks, wastewater treatment, oil water separators, sulfur recovery units, flaring, miscellaneous process vents, loading losses, vapor recovery units, and reformers for refineries. The API Compendium notes the following non-GHG sources which may be present at refineries: Cooling Towers; Equipment Leaks from liquid process streams[9]; Product Tanks (e.g. gasoline tanks)[1]; Oil/Water Separators; and Process Drains. Marketing terminals may also be sources of VOC emissions (such as from equipment leaks and storage tanks), but not sources of GHG emissions. API members have concluded that there are no GHG emissions from these sources, and therefore they should not be included in a GHG inventory.

In EPA's "Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases", it shows on page 12 that Asphalt Blowing, Delayed Coking, Equipment Leaks, Storage Tanks, Wastewater Treatment, and other sources are equal to less than 0.8% of a total refineries GHG emissions. In addition the pie chart shows flaring to be 1.6% of emissions from a refinery which industry believes is an over-estimate. Also the Sulfur Plant is shown on the graph to contribute roughly 1.9% of overall GHG emissions. Adding these insignificant sources together, indicates that they represent only 4.3% of total refinery emissions yet require a large portion of the work to estimate emissions. API estimates that having a de minimis threshold of 5%, could reduce the compliance cost and labor burden by 50%.

> **API is conducting a survey of elements related to EPA's cost assumptions for the reporting rule. API will provide the results of the survey in a separate submittal.**

[9] Note that if site specific data indicates CH_4 or CO_2 are present in the vapors, methodology is provided for emission calculations in Appendix B.

Also in the same Technical Document for Petroleum Refineries, on page 18 there is a graph showing the breakdown of greenhouse gases. N_2O and CH_4 together account for less than 1% (on a CO_2e basis) of an average refinery's emissions. These should also be able to be counted in the de minimis threshold.

78. *EPA requests comment "on the engineering methods available to estimate coke burn-off rates, the uncertainty of the methods, and the measurements or parameters and enhanced QA that can be used to verify the engineering emission estimates and their certainty." (p. 16541)*

API comments: EPA rule 40 CFR 63, Subpart UUU (April 2002) and EPA rule 40 CFR 60, Subpart Ja (July 2008) provide an approach to estimate the coke burn rate using the "K_1, K_2, K_3" approach. This coke burn rate equation is:

$$CC = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right) \quad \text{Eq. 1}$$

The volumetric flow rate of exhaust gas before entering the emission control system is calculated using the following equation:

$$Q_r = \frac{79 \times Q_a + \left(100 - P_{O_{xy}}\right) \times Q_{oxy}}{100 - P_{CO_2} - P_{CO} - P_{O_2}} \quad \text{(Eq. 2)}$$

The coke burned is assumed to proceed completely to CO_2. Based on this assumption and accounting for the conversion of units, the CO_2 emission rate is then calculated from the following equation:

$$E_{CO_2} = CC_{Avg} \times CF \times \frac{44 \text{ mass units } CO_2}{12 \text{ mass units C}} \quad \text{(Eq. 3)}$$

Although the EPA rule includes the use of all three "K" terms, CO_2 emissions can be estimated directly from the K_1 term. The first term in Equation 1 ([K_1 x Q_r x (P_{CO2} + P_{CO})]) is the total carbon content in the coke. With this knowledge, the carbon fraction (CF) can be determined by dividing the total carbon content in the coke by the total coke burned, as shown in the following equation:

$$CF = \frac{\left[K_1 \text{ x } Q_r \text{ x } \left(P_{CO_2} + P_{CO}\right)\right]}{\left[K_1 \text{ x } Q_r \text{ x } \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \text{ x } Q_a\right) - \left[K_3 \text{ x } Q_r \text{ x } \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \text{ x } Q_{oxy} \text{ x } P_{O_{xy}}\right)}$$

Substituting the CC and CF terms into Equation 3 results in the following equation:

$$E_{CO_2} = \left\{ \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO} \right) \right] + \left(K_2 \times Q_a \right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2} \right) \right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}} \right) \right\}$$

$$\times \frac{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO} \right) \right]}{\left\{ \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO} \right) \right] + \left(K_2 \times Q_a \right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2} \right) \right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}} \right) \right\}}$$

$$\times \frac{44}{12}$$

Which reduces to the equation shown below:

$$E_{CO_2} = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO} \right) \right] \times \frac{44}{12}$$

Therefore, by inspection, the CO_2 emissions can be estimated directly from the K_1 term without introducing the error associated with K_2 and K_3 terms and the coke carbon fraction. As a result the measured parameters are limited to P_{CO2} (the percent CO_2 concentration in regenerator exhaust), P_{CO} (the percent CO concentration in regenerator exhaust), Q_a (the volumetric flow rate of air to regenerator as determined from control room instrumentation, Q_{Oxy} (the volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation, and P_{O2} (the percent O_2 concentration in regenerator exhaust).

79. API requests that EPA explicitly exclude the two small (combined 3,300 bbls/day) middle distillate "topping" plants ("Topping Plants") located at the Prudhoe Bay and Kuparuk Fields on the North Slope of Alaska from coverage as petroleum refineries under 40 CFR Part 98 Subpart Y. The Topping Plants produce what is referred to as arctic heating fuel, that is similar to diesel, and a small quantity of jet fuel (approximately 4% of the total production). The majority of the arctic heating fuel is used as oil well freeze protection fluids as part of the field drilling operations. It is not combusted. The jet fuel is burned in company aircraft that are used for Kuparuk and Prudhoe Bay operations. A portion of the arctic heating fuel is combusted in emission sources on the North Slope at facilities that will likely be subject to Subpart C reporting if greater than 25,000 metric tons per year. A small portion of the production (approximately 2 %) is sold to third party oil and gas operators for combustion in equipment at other North Slope oil fields. Regulation of the Topping Plants under 40 CFR Part 98 Subpart Y does not appear necessary to capture reporting of the vast majority of the distillates produced at these topping plants and instead would lead to double and possibly triple reporting of the same volume. This exemption request is similar to past exemptions that recognize the uniqueness of the North Slope and its challenges. See for example NSPS KKK at 40 CFR 60.633(e) where EPA recently exempted certain North Slope equipment from the routine monitoring requirements of 40 CFR 60.482.

80. Preamble, p. 16541. EPA notes that *"The selected monitoring methods for this proposed rule generally follow those used in other reporting rules as well as those recommended in the*

American Petroleum Institute's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry." (p. 16541)
API comments: API greatly appreciates the inclusion of the API Compendium, however industry's review of the proposed rule has indicated some inconsistencies. Key examples of differences and deviations from the API Compendium, which are elaborated throughout these comments, include methods related to the following: fugitive emissions, flares, oil/water separators, wastewater treatment, glycol dehydrators, acid gas removal, tank flashing emissions, FCCUs, asphalt blowing, coke drums, equipment blowdowns, pneumatic devices, chemical injection pumps, and non-routine activities.

b. Additional API Comments:

81. §98.250(a). EPA should clarify that the definition of the source category does not include facilities where the equipment engaged in activities specified in §98.250(a) is shutdown and the facility operates only as a fuels distribution terminal.

82. §98.250(a). EPA should clarify the definition of the source category while it includes facilities engaged in producing lubricants, does not include facilities with the sole purpose of producing lubricants by blending of feedstocks (or base oils) where the facilities do not distill, redistill, crack or reform petroleum derivatives.

83. §98.252(a). §98.252(a) notes "*For each stationary combustion unit, you must follow […] subpart C of this part.*" This statement implies that reporting of combustion emissions for subpart Y must be performed on a unit-level basis. This is in contrast to the requirements of subpart C, which does not require unit-level reporting. Subpart C allows emissions to be reported on a unit-level, aggregate, common stack, or common pipe basis. The methodologies presented in subpart C, including the alternatives to unit-level reporting, are adequate for calculating emissions from combustion sources subject to Subpart Y. For this reason, it is recommended that the words "For each stationary combustion unit" be deleted from §98.252(a).

84. [Page 16683]Sec. 98.253 Calculating GHG emissions.
Flares operate over a very wide range of flows and measurement devices are often calibrated to be more accurate at the high or low end of the expected flow depending on the perceived need to be more accurate for routine flaring or upset flaring. When operated outside this range the reporter should attempt to use engineering methods to determine a more reliable estimate.

API offers the following revised language for this section's paragraph (b) at this time.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) and (2) of this section for combustion systems fired with refinery fuel gas.

(1) Calculate the CO_2 emissions according to the applicable requirements in paragraphs (b)(1)(i) through (iii) of this section.

(i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare or for the periods when the flow was outside its

calibrated range, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.
(ii) Carbon content. If you have a continuous higher heating value monitor or carbon content monitor on the flare or if you monitor these parameters at least daily, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare. If you monitor carbon content, calculate the CO_2 emissions from the flare using the applicable equation in Sec. 98.33(a). If you monitor heat content, calculate the CO_2 emissions from the flare using the applicable equation in Sec. 98.33(a) and the default emission factor of 60 kilograms CO_2/MMBtu on a higher heating value basis. *If you measure the density or specific gravity of the flare, you must use a correlation of the density or specific gravity to the carbon content of the gas to determine the emissions factor.*

85. §98.253. Standard conditions are defined in §98.6 as 60 °F and 14.7 psia. However, the molar volume conversion of 849.5 scf/kgmole presented throughout the subsection equates to 68 °F and 14.7 psia. The correct molar volume conversion should be 836.2 scf/kgmole.

86. §98.253(b)(ii, iii). The headings for sections §98.253(b)(ii, iii) do not clearly match the purpose of the section, leaving the regulations for refinery flare CO_2 emission estimation confusing. The regulations/section headings should be clarified.

87. §98.253(b). Refinery flares emit a small percent of refinery CO_2e emissions, yet under the proposed rule have extensive reporting requirements. Instead of detailed calculation approaches, flare emissions should allow any of the following: 1) include as a de minimis source type and exempt from annual reporting; 2) include using a one-time calculation to demonstrate annual compliance; 3) exempt from reporting requirements if equipped with a flare gas recovery system.

88. §98.253(b). The CO_2 emission calculations for refinery flares do not take combustion efficiency into account. However, both the definition of flare combustion efficiency (p 16621) and the flare equation in Subpart W (p 16677) provide a 98% flare efficiency for steam or air aspirated flares.

89. §98.253(b). Brackets should be added to Eq. Y-1 to indicate the proper use of the summation. In addition, the use of the variable “N” or “n” should be consistent. (In the variable definition, the letter is lower-case.)

90. §98.253(c). Brackets should be added to Eq. Y-2 to indicate the proper use of the summation.

91. 98.253(c), (e) and (g): Regarding the estimation of CH_4 and N_2O from the following processes: catalytic cracking, catalyst reforming, and coke calcining - the “coke” used in the rule for this determination is petroleum coke, a product. However, the processes applying this

conversion are catalyst coke. The emission factors are not appropriate for catalyst coke. An assumption of 0 emissions is as accurate as applying the proposed methodologies.

92. §98.253(c). As currently defined, the variables EmF_1 and EmF_2 are being misapplied in Eqs. Y-4 and Y-5. Either the terms should be flipped in the equations or the variable definitions should be switched. As currently presented, CO_2 emissions are being multiplied by a CO_2 emission factor then divided by a CH_4 (or N_2O) emission factor. Also, thought should be given as to whether the two equations should use the same variables (EmF_1/EmF_2) in two different equations; to avoid confusion they should perhaps be differentiated.

93. §98.253(e)(2). The catalyst reforming material balance equation (Eq. Y-6) applies a coke burn-off value. This differs from the engineering estimate approaches provided in California's AB-32 reporting rule [Citation: §95113(b)(2)] and the API Compendium, which both calculate CO_2 emissions based on the difference between the carbon fraction of the spent catalyst and the carbon fraction of the regenerated catalyst, an equally accurate estimation method. As noted previously, emission estimates developed under duly enacted state programs should be acceptable and sufficient for meeting reporting obligations.

94. §98.253(g). Regarding the emission estimation approach for coke calcining, the aluminum industry is a user of calcined coke, not a producer. For this reason, the methodology developed by the aluminum industry should not be adopted as the industry standard for estimating CH_4 emissions. Actual operations indicate that the approach developed by IAI does not accurately estimate CH_4 emissions, and that site-specific adjustments are necessary. As such, CH_4 emissions should be calculated using best engineering practice.

95. §98.253(h). Uncontrolled asphalt blowing CH_4 emissions can be calculated using a facility-specific emission factor, as noted in the variable definition for the asphalt blowing emission factor (EF_{AB}) in Eq. Y-10. However, the definition for EF_{AB} when used to calculate controlled CO_2 emissions does not indicate that facility-specific emission factors are allowed. Facility-specific factors should be allowed when estimating both uncontrolled CH_4 and controlled CO_2 emissions from asphalt blowing. In addition, the API Compendium provides a simple emission factor for uncontrolled asphalt blowing from AP-42 (EPA, AP-42, Section 5.1.2.10, 1995). The AP-42 emission factor for asphalt blowing is assumed to be on an air-free basis (AP-42 does not specify this, but notes the factor represents "emissions"). A gas composition is needed to estimate the CH_4 emissions when using the simple emission factor approach.

96. §98.253(h). For asphalt blowing, EPA assumes that only CH_4 is converted to CO_2. This ignores other carbon compounds (C2+). The API Compendium cites a study where other carbon compounds are shown to be present in concentrations similar to CH_4, on an air-free basis.

The CH_4 factor for asphalt blowing is the same as is used in EPA's *Inventory of Greenhouse Gas Emissions and Sinks*, which is based on 1% CH_4. This value is not consistent with the study cited in the API Compendium, which suggest a CH_4 concentration of 13%, on an air free basis.

97. §98.253(i). Reporters with delayed coking units are required to calculate CH_4 emissions from the depressurization of the coking unit vessel to the atmosphere using the methods from

process vents not specifically referenced and to calculate CH_4 emissions from the subsequent opening of the vessel for coke cutting operations.

Methane emissions from the depressuring of coking unit vessels and during coke cutting are small and should be considered as de minimis. Coking unit vessels are typically depressured and steamed, initially to the main fractionator ("little steam"), and then at higher rates through a quench column into a closed blowdown system ("big steam). Methane contained in the wet gas depressured from the coking vessel will end up in the coker gas plant during the "little steam" and in the overhead of the blowdown system settler during the "big steam". The uncondensed gases off the blowdown settling drum are routed to an offgas vapor recovery system or a fuel gas system. (see Figure 2 in the following citation:

www.conocophillips.com/NR/rdonlyres/0470A627-E691-49AF-BBF6-F83AD3F44F9A/0/05PTQCokingArticle.pdf)

Therefore, any CH_4 present in the coke drum will ultimately end up in a fuel system. The methodologies proposed in the rule to account for CH_4 emissions from coke drum depressuring and coke drilling operations appear to not account for this practice. The coke drum is then usually water quenched and drained, and only then opened to the atmosphere. Considering this typical practice of preparing a coke drum for cutting, Eq. Y-11, proposed for calculating CH_4 emissions from the coke cutting operation seems to have many sources of error which will significantly overestimate the quantity of CH_4 during cutting.

Eq. Y-11 is based upon the empty volume of the coke drum. In fact the drum is not empty when it is opened for cutting, but rather is 85-90% loaded with coke. Therefore, the volume term $(H*\pi D^2/4)$ should be multiplied by the in-drum porosity of the coke, ε. The Petroleum Refinery TSD indicates that coke is "quite porous". While there is not an abundance of data on this term, the maximum porosity for coke is generally considered to be 0.20 or less, which API would argue falls short of quite porous. However, Eq. Y-11 should also adjust for the ratio of the absolute pressure of the coke drum when it is opened (usually 2-10 psig) to the atmosphere $[(P_{depressure}+P_{atm})/P_{atm}]$. Given a typical degassing pressure of 5 psig and the above referenced maximum porosity of 0.20, the addition of these terms reduces the expected CH_4 to the atmosphere during coke cutting by approximately a factor of 0.27 from what is proposed in the rule. However, the largest error comes from the default CH_4 concentration assumed, (0.03 kg-moleCH_4/kg-mole of gas). Given that the coke drum has already been steamed to the blowdown system for 1-1.5 hours, it seems unreasonable to use a default CH_4 concentration of 0.03 mole percent, which was estimated as 10% of the concentration of CH_4 in coker dry gas. Given the steaming that has taken place, API believes the default value is off by at least an order of magnitude. If all of these corrections are incorporated, the true value is lower than what is predicted by Eq. Y-11 by a factor of 0.03. API thinks these data support the assessment that this operation is indeed de minimum with regard to emissions of CH_4 and other greenhouse gases from coking vessel unit depressuring and coke cutting operations.

98. §98.253(j). EPA's intended emission source covered by the provision for process vents beyond those in §98.253(a)-(i) is unclear. EPA should clarify that this provision applies to process vents released to the atmosphere after controls, if they exist. The provision should include a de minimis reporting level based on carbon content, flow rate, and/or emissions. EPA has already determined the process vents with the majority of the GHG emissions and specified

emission methodologies for them in §98.253(a)-(i). Thus, the emissions from these vents are probably insignificant compared to the total GHG emissions from the refinery.

99. §98.253(j). In Eq. Y-12, the use of the variable "N" or "n" should be consistent. (In the variable definition, the letter is upper-case.)

100. §98.253(k). EPA's intention for sources covered by the provision for uncontrolled blowdown systems is unclear. The definition in §98.6 says '*blowdown'* means *"manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance."* EPA should clarify that §98.253(k) does not apply to vents sent to flares since the emissions from flaring are calculated under §98.253(b). For a 500,000 barrel of crude per year refinery (upper bounds for crude throughput), the CH_4 emissions calculated by equation Y-8 is 1.3 metric tons per year. According to the Table Y-2 on page 16540 of the preamble, 99.3% of the U.S. refineries have direct GHG emissions that exceed 10,000 metric tons CO_2e per year. Thus, the emissions from uncontrolled blowdown systems from a large refinery are conservatively less than 0.013% of the refinery's total direct GHG emissions. Even if the intermediate products received from off-site are assumed to be equal to the crude rate, which is an over estimate, the blowdown emissions become 2.6 metric tons per year or 0.026% of the refinery's total GHG emissions. This level of reporting is not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions (pg 16468).

101. §98.253(l). Equipment-level emissions from equipment leaks can only be estimated using EPA's Protocol for Equipment Leak Emission Estimates or the EPA derived equation, which applies CH_4 concentrations for refinery process units which are not cited or otherwise referenced (Table A-4. Estimated Methane Concentration and Fugitive Emission Rates for Model Refinery Process Units. EPA, *Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases*, 2008.)

API conducted a study to quantitatively assess the contribution of fugitive CH_4 emissions from equipment leaks to overall refinery GHG emissions. Emissions were estimated based on component counts in natural gas and refinery fuel gas service, using average emission factors for components in gas service provided by EPA (EPA, 1995). Fugitive CH_4 emissions were calculated for two refineries:

- A smaller fuels refinery with a rated capacity between 50,000 and 90,000 bbl feed/day; and
- A larger refinery/petrochemical complex with a rated capacity between 100,000 and 199,000 bbl feed/day.

Results indicated that CH_4 emissions from equipment leaks represent 0.11% of total GHG emissions for the smaller refinery and 0.19% of total emissions for the large refinery. Since other large GHG emitting sources have uncertainties within the range of 1% to 5% of the overall GHG inventory, a CH_4 fugitive emission contribution of 0.1% appears to be negligible. A summary report on the study is provided in Appendix F of the Compendium. These results justify being de minimis, using simplified emission estimates or best engineering calculations.

102. §98.253(l). When estimating emissions from equipment leaks with component level emission factors, only emission factors provided in the Protocol for Equipment Leak Emissions Estimates can be used. This disregards emission factors developed by other organizations and studies. As noted above, the contribution of fugitive emissions to a refinery's overall GHG inventory support the use of alternative and less detailed emission estimation methods.

103. §98.253(l). The equipment-based emission factors in Eq. Y-14 (e.g. 0.4 metric tons CH_4/yr-atmospheric crude oil distillation columns) should be defined in the variable definitions.

104. §98.253(m) – The CH_4 emissions from storage tanks other than those processing unstabilized crude oil for a 500,000 barrel of crude per year refinery (upper bounds for crude throughput) using equation Y-15 is 0.05 metric tons per year. According to the Table Y-2 on p. 16540 of the preamble, 99.3% of the U.S. refineries have direct GHG emissions that exceed 10,000 metric tons CO_2e per year. Thus, the CH_4 emissions from storage tanks other than unstabilized crude oil from a large refinery are conservatively 0.0005% of the refineries total direct GHG emissions. Even if the intermediate products received from off-site are assumed to be equal to the crude rate, which is an over estimate, the tank emissions become 0.1 metric tons per year or 0.001% of the refinery's total GHG emissions. This level of reporting is not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions (p. 16468).

105. §98.254. Catalytic cracking units calculating emissions using Eq. Y-3 as an alternative to using a CO_2 CEMS are required to monitor %CO, %CO_2, and %O_2. According to 40 CFR §63 Subpart UUU, these continuous parameter monitoring systems must be installed, operated, and maintained each according to the requirements §63.1572(c). However, 40 CFR §63.1572 is not incorporated by reference in §98.254; §98.254 only addresses CO_2 CEMS and flow rate monitors.

106. [Page 16688]Sec. 98.254 Monitoring and QA/QC requirements.
For Subpart Y Sec. 98.254, API offers the following revised text at this time**.**

(a) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated or verified following good industry practice, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, etc.). Alternatively, calibration or verification procedures specified by the device manufacturer or developed by the facility may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated or reverified either annually or at the minimum frequency consistent with good industry practice.

(b) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. If the calibration or verification frequency is other than annual, the owner or operator will document the basis for the selection of the interval. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(c) All CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in Sec. 98.34(e).

107. Sec. 98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

API comments: API noticed an inconsistency in the missing data requirements between Subparts C and y. There is also an inconsistency within Subpart Y on the missing data procedures to use.

Some systems, such as laboratory information systems, used to calculate the reported quantity, store or use the last valid value for calculations until it the value is updated. For reasons of good business controls, it would be better to restrict user intervention to reset input values to a minimum case where the intervention makes a significant difference. This saves effort on making minor edits and improves documentation of the development of the reported values.

(a) For each missing value of the heat content, carbon content, or molecular weight of the fuel, the substitute data value shall be the *quality-assured value of that parameter immediately preceding the missing data incident. If the quality assured value immediately following the missing data incident is different by more than ten percent of the preceding value, the* arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident will be used. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

Subpart HH – Landfills (98.340)

a. EPA Requested Feedback

108. *EPA requests comment "on the exclusion of land application units." (p. 16558)*

API comments: API supports the exclusion of land application units from the reporting rule subpart HH. In addition, API requests exclusion of inactive industrial landfills that were never open to the public, such as exist at some refineries. Greenhouse gas emissions from these operations are extremely small, and do not justify the monitoring, reporting, and QA burden.

b. Additional API Comments

109. §98.340. EPA's language defining landfills is very general and could potentially pull in sources at the refineries – inactive, non-public areas where spent materials were buried. API will attempt to offer an amended definition. As noted above, GHG emissions from these operations are extremely small, and do not justify the monitoring, reporting, and QA burden.

110. §98.340(a). As stated in §98.340(a), the source category consists of MSW landfills and industrial landfills including but not limited to landfills located at food processing, pulp and paper, and ethanol production facilities. EPA states in the preamble in Section V.HH.1 (page 16557) that the majority of CH_4 emissions from onsite industrial landfills occur at pulp and paper facilities and food processing facilities and provides data on the emissions from these sources. EPA does not provide emissions data for other industry sectors' onsite landfills to demonstrate the emissions are significant to warrant reporting. Also, Table HH-1 on page 16703 only

provides default values to be used for calculating landfill emissions for food processing facilities and pulp and paper facilities confirming for industrial sources only emissions from pulp and paper facilities landfills and food processing facilities landfills are significant enough to warrant reporting. Therefore, the source category should be revised to include only MSW landfills and industrial landfills at pulp and paper facilities and food processing facilities.

111. §98.340(a). Onsite industrial landfills that have been closed under RCRA should be excluded from the source category. Landfills closed under RCRA have little to no potential for air emissions.

112. §98.343. Equations HH-6 through HH-8 use stars to indicate multiplication. These should be replaced with traditional symbols for multiplication (e.g. "X"). This issue is not limited to subpart H; EPA is inconsistent throughout the proposed rule with the use of "*" or "X" or alternate symbols to indicate multiplication.

Subpart II—Wastewater Treatment (98.350)

a. EPA Requested Feedback

113. *EPA requests "comment on monthly sampling of digester gas CH_4 content as an alternative to a continuous composition analyzer." (p. 16560)*
API comments: API requests specific exclusion of wastewater treatment operations and oil/water separators at refineries. Anaerobic wastewater treatment is extremely rare, and estimating CH_4 emissions based on a conversion of VOC emissions from oil/water separators is not appropriate. GHG emissions from these operations at refineries are extremely small. The requirement as provided in the MRR would impact a large number of extremely small operations. The methodology, monitoring, reporting, and QA requirements are extreme for such very small emission sources.

114. *EPA requests comment on "the advantages and disadvantages of using these tools [e.g. National Council of Air and Stream Improvement's GHG Calculation Tools for Pulp and Paper Mills] as a model for tool development and the utility of providing such a tool." (p. 16561)*
API comments: API does not support the inclusion of refinery wastewater treatment operations or oil/water separators in the mandatory reporting rule. The emissions contribution is extremely small and does not justify the monitoring, reporting, and QA burden. As a result, a tool is not needed to assist refineries in reporting emissions from these operations.

b. Additional API Comments

115. §98.350(a). EPA should clarify if the emissions from only anaerobic wastewater treatment processes or from either anaerobic or aerobic wastewater treatment processes should be reported. §98.350(a) says to report CH_4 emissions from anaerobic wastewater treatment processes. However, this statement conflicts with the emissions methodology in §98.353(a). §98.353(a) says to calculate CH_4 emissions from treatment processes other than digesters using equation II-1 and the equation includes a methane conversion factor (MCF) from Table II-1. There are four MCF values in Table II-1, two are for anaerobic systems and two are for aerobic systems. Also, the monitoring and QA/QC requirements in §98.354(c) only discuss requirements for anaerobic systems.

116. §98.352(b). §98.352(b) requires refineries to report CO_2 emissions from oil/water separators. Oil/water separator as defined in §98.6 means equipment used to routinely handle oily-water streams, including gravity separators or ponds and air flotation systems. Does EPA intend the definition of oil/water separator to include stormwater ponds? Clearly stormwater ponds contain less hydrocarbon than process water ponds and thus will have less CO_2 emissions from the degradation of hydrocarbons.

117. §98.353(b). Oil/water separators at petroleum refineries have been included for reporting as the CO_2 emissions are considered anthropogenic emissions (Preamble, p.581). The 2009 API Compendium currently includes this source in Appendix E, in a list of VOC emission sources that are not sources of GHG emissions. This emission estimation method is extremely onerous for such a small GHG emission source, particularly when considering the burden for measurement, monitoring, reporting, and QA.

EPA also suggests that influent should be measured for oil/water separators. These are generally sewers, which are not in the best location to accurately measure a flow (see further comments below). The language also could be interpreted to include covered oil/water separators, which would not be a source of GHG emissions. EPA is catching a number of very small separators, with very small emissions. This goes back to previous comment of undue burden for measurement, reporting, QA on very small emission sources.

In addition, this is the only source in the MRR that considers the atmospheric oxidation of VOCs to form CH_4, which is the basis of the 0.6 conversion factor. This conversion is not considered anywhere else in the rule as VOC is not a GHG, as defined in the rule. This extrapolation is not appropriate at a facility level (IPCC considers this conversion from national inventories).

118. §98.353(b) and (c). Equations II-2 and II-4 are inconsistent with the rest of the proposed rule in presenting variable units in the equation. Variable units should be presented in the variable definitions only.

119. §98.353(c). Equation II-3 requires the quantity of CH_4 generated by anaerobic digesters be previously calculated using Eq. II-4. The order of the equations should be rearranged to present calculations in a logical format.

120. §98.354(c). The monitoring requirements in §98.354(c) state the location for the COD sample must represent the influent to the treatment process and the location of the flow sample must correspond to the location of the COD sample. For treatment processes that are designed with a staged saturated air treatment unit that flows into an aeration basin, the sampling location should be representative of the influent into the staged saturated air treatment unit.

121. §98.354(c). The monitoring requirements in §98.354(c) state the location for the COD sample must represent the influent to the treatment process and the location of the flow sample must correspond to the location of the COD sample. Refineries and petrochemical plants do not have flow meters on the influent because (1) NPDES monitoring point is on the outfall, (2) operation of meters in oily water service is problematic, and (3) accuracy of flow meters in a gravity flow, possibly phase separated system is a concern. As an option to inlet flow meters,

reporters should be allowed to use outlet flow meters or engineering determination. This option is consistent with California's GHG emissions reporting program.

122. §98.354(c). The monitoring requirements in §98.354(c) state the location for the COD sample must represent the influent to the treatment process and requires reporters to collect a 24-hour flow-weighted composite sample at least once per week. Refineries and petrochemical plants draw COD samples at the wastewater treatment plant discharge under NPDES permit. Maintaining a compositor on the influent will be problematic because the waste contains oil and sediments. Consistent with California's GHG emissions reporting program, reporters should be given the option to take daily grab samples on the influent for TOC and use a conversion factor to convert TOC to COD.

123. §98.358, Table II-1. The emission factors for "DAF or IAF - uncovered" and "DAF or IAF - covered" appear to be shown to the wrong order of magnitude (E^{-34} and E^{-44}, instead of E^{-3} and E^{-4}, respectively). Refer to California's AB-32 reporting rule, Table 13, where the '4' is a footnote not part of the exponent.

Subpart MM - Suppliers of Petroleum Products (98.390)

a. EPA Requested Feedback

124. *EPA requests comments on the "proposed definition of petroleum products as it applies to importers.", and the proposal that "all exporters report on their exported petroleum products." (p. 16571)*

API comments: EPA should clarify the scope of the Subpart MM reporting requirements for importers and exporters of NGLs. The Preamble to the proposed rule clearly states that blenders of petroleum products would not be required to report upstream emissions associated with their production. However, the definitions of "importer" and "exporter" in the proposed 40 CFR § 98.390 expressly include blenders. The final rule should be clearly revised to exclude blenders from the Subpart MM reporting requirements.

In addition, the Preamble to the proposed rule and the proposed 40 CFR § 98.390 state that only importers and exporters of petroleum products need report under Subpart MM. However, Subpart MM also requires covered importers and exporters to report imports and exports of natural gas-derived NGL products. It is not clear whether this reporting requirement only applies to importers and exporters engaged in the petroleum product supply chain, as § 98.390 implies, or whether *any* entity that imports and exports NGLs would be required to report. Since shippers using international pipelines may be subject to this provision, the final rule should clarify this point.

The definitions of "importer" and "exporter" should only encompass entities that own or hold title to imported and exported products. EPA should confirm in the final rule that entities that merely transport petroleum products, without holding title or paying customs duties, do not have a reporting obligation. In addition, the proposed definition of an "importer" closely parallels the definition provided in U.S. Customs and Border Protection (CBP) regulations. In order to avoid confusion as to who must report under the exporter/importer provisions of the proposed rule, EPA should clarify the rule by more explicitly linking its definition to entities that are already considered importers of record or exporters of record (Principal Parties in Interest) in CBP regulations.

Suggested change regarding importer/exporter and blender.

40 CFR § 98.6. *Importer* shall have the same meaning provided in 19 C.F.R. § 101.1, and means the person primarily liable for the payment of any duties on the merchandise, or an authorized agent acting on his behalf. The importer may be:

(1) The consignee, or
(2) The importer of record, or
(3) The actual owner of the merchandise, if an actual owner's declaration and superseding bond has been filed in accordance with § 141.20 of this chapter, or
(4) The transferee of the merchandise, if the right to withdraw merchandise in a bonded warehouse has been transferred in accordance with subpart C of part 144 of 19 CFR.

40 CFR § 98.6. *Exporter* shall have the same meaning provided in 15 C.F.R. § 30.4(a)(1), and means the person in the United States that receives the primary benefit, monetary or otherwise, of the transaction. Generally that person is the U.S. seller, manufacturer, order party, or foreign entity.

40 CFR § 98.390. This source category consists of petroleum refineries and importers and exporters of petroleum products. … (c) Importer has the same meaning given in § 98.6. A blender or refiner of refined or semi-refined petroleum products shall be considered an importer or exporter if it otherwise satisfies the aforementioned definition. ~~and includes any blender or refiner of refined or semi-refined petroleum products~~. (d) Exporter has the same meaning given in § 98.6. A blender or refiner of refined or semi-refined petroleum products shall be considered an importer or exporter if it otherwise satisfies the aforementioned definition. ~~and includes any blender or refiner of refined or semi-refined petroleum products~~.

In general, the requirements for NGL reporting would be easier to comprehend if they were gathered together under one subpart, rather than divided among Subparts MM and NN. Doing so would minimize the risk of confusion and inadvertent regulatory violations.

Suggested clarification regarding NGLs in Subparts MM and NN.

Subpart MM – delete all references to reporting of NGLs, except for NGLs used as a feedstock by domestic petroleum refiners.

40 CFR § 98.400 This supplier category consists of natural gas processing plants, ~~and~~ local natural gas distribution companies, and importers and exporters of natural gas liquids (NGLs)…. [insert after paragraph (b)] (c) Importers and exporters are defined at 40 CFR § 98.6. A blender shall be considered an importer or exporter if it otherwise satisfies the aforementioned definition.

125. *EPA seeks comment "on whether or not to establish a de minimis level, either in terms of total product volume or potential CO_2 emissions, to eliminate any reporting burden for parties that may import or export a small amount of petroleum products on an annual basis." (pp. 16571-16572)*
API Comment: The MRR does not include a threshold for the amount of petroleum products that a supplier must import or export in order to be subject to reporting. API requests that a threshold for the amount of petroleum products equivalent to 25,000 metric tonnes of CO_2e when combusted be included in the rule.

126. *EPA seeks comment on proposing that "reporters could either use the default CO_2 emission factors for each product type […] or, in the case of petroleum products and NGLs, develop their own factors." (p. 16572)*
API Comments: API supports the flexibility to use either option.

127. *EPA requests "comment on whether reporters should be allowed to combine default CO_2 emission factors to develop alternative factors for fuel reformulations according to the volume percent of each fuel component, and if so using what methodology." (p. 16572)*
API comments: As there are currently no default emission factors for fuel mixtures, Calculation Methodology 1 cannot be used to estimate combustion emissions from fuel mixtures. However, since CO_2 emissions are based on the carbon content of the fuels, multiplying the volume of each pre-mixed fuel by its respective fuel-based emission factor would result in an accurate estimate of CO_2 for the fuel mixture. Clarification should be added to Subpart MM as to how emissions from fuel mixtures should be estimated, without the use of carbon content measurements.

128. *EPA seeks "comment on the appropriateness and adequacy of the proposed default CO_2 emission factors - including factors for biomass products - and ways to improve these default values." (p. 16572)*
API comments: The EPA emission factors were compared to those in the API Compendium, which are cited primarily from the Energy Information Administration. When compared on the same units basis, the API and EPA values compare very well for the common fuel types. However, the EPA MRR provides more a detailed list of fuel types than the API Compendium. For example, EPA lists four types of motor gasoline (conventional and reformulated summer and winter blends), while the Compendium cites just one emission factor for gasoline. Based on this comparison, the emission factors seem adequate and appropriate.

129. *EPA requests comment on the "proposal to require petroleum product suppliers to report the CO_2 emissions associated with products that could potentially have non-emissive end-uses [and] on ways in which non-emissive end-uses could be tracked and reported." (p. 16573)*
API comments: CO_2 emissions should not be reported for products that are not combusted (e.g. asphalt produced for road application). Estimating these emissions skews the emissions estimate to be artificially too high.

130. *EPA requests "comments on ways to take advantage of existing reporting and verification programs, particularly those related to transportation fuels. Specifically, […] on requiring annual attest engagements for all reporters […] we seek comment on an alternative deadline of February 28 following the reporting year for annual reports." (p. 16575)*
API comments: A reporting deadline of February 28 does not allow adequate time for inventory preparation. As detailed previously and during preliminary discussions with the U.S. EPA, API would support annual reports on a calendar year basis, with reports due 6-12 months after the close of reporting year, for an initial program that is of finite duration and is designed to collect data for policy development.

b. Other API comments

131. Refiners should not be required to provide crude data. This data will not be used to determine carbon emissions from the refinery; therefore, it should not be required. If EPA needs this data for some other reason, it is already published by EIA data (EIA form 814).

There is no valid reason to require an attest engagement from fuel suppliers for a reporting rule. This requirement is not imposed on any other industry. While other fuels programs have such a requirement, those engagements are intended to ensure that the environment benefits of the various fuel programs are achieved. There is no reason to include this costly and time consuming requirement to a reporting rule.

Regarding the measurement methods proposed on p. 1344-1345 for measuring the quantity of petroleum products, including all intermediates shipped off site, coke, natural gas liquids, and all feedstocks entering/leaving the refinery, some of the flow meters used for shipping volumes are operated by a 3rd party outside the refinery such as a pipeline company, terminal operator and/or shipping agents measuring tank levels for marine shipments and therefore this activity is not something that refinery personnel have direct control over. Also, positive displacement flow meters are used for some crude service.

The regulations should allow the option for industry to be able to use the current volume measurement systems that are in place for custody and title transfer.

The requirement that all petroleum products need to be measured by flow meters or tank gauges (98.394 (a)) seems to exclude solids, such as petroleum coke. Coke quantities may be determined by weighing in and out the coke trucks delivering the coke. This section should include some indication of the acceptability of measuring weight of solids.

EPA needs to make sure that a reasonable sampling program is defined and implemented. API is assuming "*samples of each petroleum product and NGL*" can be interpreted to mean a representative sample of that stream during the month. Other options, such as sampling the shipping tank every time a shipment goes out, or sampling every tank that a shipment could pump out of would be unnecessarily burdensome. Also, keeping monthly samples and compositing them for analysis at the end of the year seems unreasonable. An alternative would be to analyze the samples each month and volume weight them together at the end of the year. Monthly tracking is likely to be required for planning anyway. Also, when a refiner tests to establish an emission factor, that facility should be able to establish a factor and then be able to reduce testing frequency based upon a lack of data variability.

EPA needs to make sure that double accounting is avoided on products that are produced at the refinery, shipped out and then returned to the refinery at a later date, such as the movement of butane from the refinery during the summer and return of the butane during the winter.

Regarding the data reporting requirements on p. 1346-1350, physical properties of materials that can are tested on-site can be reported. Other specific information about the origin of the material many times is not available to the refinery, as historically this is fairly irrelevant compared to the physical properties.

132. API believes petroleum fuel refiners, importers, and exporters should not have to conduct additional reporting on petroleum feed stock, product volumes, and GHG emissions to EPA. API already provides extensive data on the requested volumes of finished petroleum products and feed stocks to other federal and state agencies on a weekly, monthly, and annual basis. These existing reporting schemes provide essential protection of these competitively sensitive data as Confidential Business Information (CBI). EPA would be able to have access to these data provided they agree to keep that data business confidential. Agreeing to keep the data confidential would not preclude the agency from developing emission profiles from each refinery. The proposed rule would establish duplicative reporting requirements and raises questions regarding EPA's ability to manage sensitive data as CBI. EPA should coordinate with agencies like the Department of Energy (DOE) and Customs and Border Protection (CBP) to make use of existing reporting data and processes to support development of future climate policy.

As designed, the current reporting system will result in significant overstatement of emissions for some facilities as clearly some products are not combusted. The concern is twofold. First, there are the products that will not be combusted (asphalt, lubes, etc.). These should be flagged or excluded somehow. The reporting facility could report the volumes, but indicate these would not be combusted. That is, there should be some way to indicate the end use of the product. The second area is those feedstocks that will either have to be further processed or blended (for example, naphtha). The refinery that processes the feedstock and produces the extra volume of product should be the one that reports. If a facility has the ability to determine that the stream will not be combusted they should be able to exclude it from their calculations.

133. The Monitoring and QA/QC requirements section 98.394 (Subpart MM) explains the intent of the EPA regarding test methods used to determine quantities. However, the references to specific test methods and editions of test methods in API's opinion will not accomplish the intent and desired goals of EPA for collecting consistent and accurate data, especially if the EPA intends for data collection to begin as soon as January 1, 2010. Some of the specific problems in these sections are:

- Many individual feedstocks and products are measured and transferred on the basis of measurement(s) systems other than meters and manual shore tank gauges. Feedstocks and product quantities received from or delivered to tank trucks at truck racks often are determined by calibrated custody transfer grade meters. If the meters are not available or malfunction (i.e. are deemed to be inaccurate), accepted measurements can include gauging of rail cars and trucks using computations from certified truck strapping tables, and/or by weighing rail cars and trucks on certified weigh scales. This is especially true for heavier liquids and petroleum coke which have a lower carbon/hydrogen ratio and might be of particular interest to the EPA.
- The words *"depending on the reporters existing equipment and preferences"* might be construed to mean that the existing equipment and methods can not be changed or upgraded. This would be contrary to the Agency's intent.
- The enumerated meter types in (a)(1) are recognized as effective technologies, but are not the only meter types that are used for transferring and measuring hydrocarbon materials. Missing from the list, for instance, are well recognized and widely used devices such as displacement meters, vortex meters, cone meters, helical turbine meters, as well as several other types that some experts might argue are either different or else subclasses of the above. These are in use and would meet the needs of the EPA. These other meters are also sometimes used to meet specific process constraints that make the use of other listed meter types less practical.
- If this rule does not automatically expire after one reporting year, using a specific enumerated list of acceptable technologies will unfairly inhibit the development of new technologies or evolutionary improvements from old technologies. This would be difficult for the process industries but it might be devastating for the equipment manufacturing companies in the U.S. which depend on innovative products to fuel their growth and influence their ability to retain and create jobs.
- (a)(1)(i) to (a)(2)(iii): The references to individual industry standards are incomplete and some editions of the standards referenced are outdated. Industry uses several different standards for these types of devices based on the scope of the standard, company preference, and type of device. API has made updates to the originally proposed series of standards but these updates do not represent a complete list.

API publishes one of the more comprehensive sets of custody transfer measurement standards, but it is neither complete nor the only widely recognized source. Even so, new or revised measurement standards are published each year. To provide a complete list of the individual standards, one would need to include the entire API Manual of Petroleum Measurement Standards (MPMS) (which comprises over 140 standards) and additional API standards. API has included a list of some of the measurements standards used in the industry, but this long list is neither complete nor inclusive of all the consensus organizations that produce suitable standards for measuring hydrocarbon materials.

Standards evolve over time to meet changing technology and user and manufacturer experience. Use of a specific edition date freezes out improvements and error correction in the standards without giving the Agency any more assurance of accuracy. The use of a phrase such as "the current edition" would be more effective than attempting to specify individual dates. In addition, equipment is installed in accordance with standards in effect at the time of design or installation, but would not necessarily be modified if the standard were subsequently changed. Calculation and test methods based on standards are often updated to follow changes in the applicable Standards**.**

Though API does not recommend this approach, for illustration API notes the following modifications to the list of standards published in the proposed Subpart MM:

- *Ultra-sonic flow meter: AGA Report No. 9 (2007).* Also include API MPMS Chapter 5.8
- *Turbine meters: American National Standards Institute, ANSI/ ASME MFC-4M-1986* Also list API MPMS Chapters 4, 5 and 6 (multiple sections).
- *Orifice meters: American National Standards Institute, ANSI[spelling]/ API 2530(also called AGA-3) (1991).* The API standard is now numbered API MPMS Chapter 14.3 and is still joint with AGA-3.
- *Coriolis meters: ASME MFC-11 (2006).* Also list API MPMS Chapter 5.6.

For tank gauges any one of the following test methods can be used to determine quantity:

- *API-2550: Measurements and Calibration of Petroleum Storage Tanks (1965).* This is outdated and for calibration should be either/or API MPMS Chapter 2 and ISO 7507 for vertical tanks and ISO 12917 for horizontal tanks. For measurement the reference should be API MPMS Chapter 3 (multiple sections).
- *API MPMS 2.2: A Manual of Petroleum Measurement Standards [incorrect title] (1995).* Included above.
- *API-653: Tank Inspection, Repair, Alteration and Reconstruction, 3rd edition (2008).* This standard does not apply it is for tank mechanical inspection, not measurement. For measurement, you would reference API MPMS Chapter 3 (multiple sections).

However, API would suggest a different construction for Section 98.394 that would allow the data to be collected on a more timely basis, with a greater degree of quality and fidelity than originally proposed. This proposed construction meets the Agency's legitimate need for accurate and quality-assured data without forcing the Agency into a near continuous cycle of re-evaluating alternative measurement technologies.

The most accurate quantity information available to the reporters is the quantities on which they base their financial records. These records are the basis for payments of which any potential "carbon costs" would be only a fraction. These records also have the benefit of being subject to audit under existing Sarbanes-Oxley regulations as well as Internal Revenue, U.S. Customs & Border Protection, and other regulatory compliance systems. Any attempt to under-report the quantity for the purpose of this rule would in application be impractical, as it would involve a third party likely to object and report the infraction, and it would result in one of the two parties having a financial loss greater than the impact of any potential new rule. A similar approach is implicitly used in 98.405 when data is missing for Natural Gas Plants.

An attempt to accumulate a separate but similar set of quantities transferred would take a substantial amount of time and resources to develop computer systems capable of recording the reported data. The separate financial and environmental quantities could easily be cross posted in the wrong system by individuals. The results would potentially corrupt both sets of data.

There are existing Federal Regulations and Statutes that are used by other agencies in the public sector that would accomplish the intent and desired goals of EPA for collecting consistent and accurate data. For example, U.S. Customs & Border Protection in its guideline for approval and validation of FTZ petroleum measurement systems (including sampling) state that petroleum measurement systems must be approved (i.e. 19 CFR 151.42 (a) (1) (i) and 151.42 (a) (3)) and are typically accepted if those petroleum measurement systems "meet or exceed the installation, operational, and performance criteria found in the 'appropriate' (sic current edition) API MPMS." This also includes 19 CFR 151.13: Approval of Commercial Gaugers ("Customs-approved gaugers must comply with appropriate procedures published by such professional organizations as the American Society for Testing and Materials (ASTM) and the American Petroleum Institute (API), unless the Executive Director gives written permission to use an alternate method. Alternative methods will be considered and approved on a case-by-case basis.").

Sec. 98.395 (MM): Procedures for estimating missing data, presents a series of options for replacing missing data, but the prescribed method overlooks the fact that a secondary set of measurements (i.e. vessel measurements), that if properly obtained in compliance with API standards, may be an accurate and acceptable alternative.

For section (a), if meters are not available or malfunction (i.e. are deemed to be inaccurate), quantity shall be based on shore tank measurements. In the event of using an active (vs. static) shore tank during any part of the transfers, or if the shore tank measurements are determined to be inaccurate or not representative of the cargo transferred, quantity shall be based on the volumes as determined from measurements of the vessel before and after the transfer with application of a Vessel Experience Factor (VEF), if determined valid (per API MPMS Chapter 17.9) and applicable.

This approach is accepted in practice and is similar to the one used in 98.405. For section (b), if there are valid volume readings, then there is no missing data or need to provide substitute data, but the Agency does have the issue of how to report for periods that may end between pipeline volume readings. API recommends that the estimated end (start)-of-period quantity be determined by prorating of the time in the reporting period. API proposes wording to accomplish that end.

For section (c), refinery changes in the volumes in inventory are reflected in the financial accounts either as inventory increases/decreases or as transactions proposed to be the basis of reporting. The sections proposed based on transactions will address any missing data portions, except for non-coincident reporting periods. For this possibility, a section similar to the pipeline section is proposed.

[Page 16717] Suggested changes in complete substitution for the identified sections 98.394 & 98.395

Sec. 98.394 Monitoring and QA/QC requirements.

(a) The quantity of petroleum products, natural gas liquids, biomass, and all feedstocks shall be determined based on the company's procedures for purposes of inventory tracking and billing using the same methods as used to measure and calculate the financial transactions for those transfers including any and all adjustments to the quantities of those transactions.

(1) For quantities measured as part of U.S. Customs and Border Protection Foreign Trade Zones, the methods described in the approved measurement

plan as well as those measurements obtained by a US Customs & BP-approved commercial gauger must be used to determine the quantity reported for this rule.
(2) For quantities reported from facilities not regulated as Foreign Trade Zones, the measurements must be of an assured level of accuracy to be acceptable under the provisions of the Sarbanes-Oxley Act, and must be compliant with the provisions of 404 of the Act.
(3) For marine-imported and exported refined and semi-refined products, the reporting party shall use the shore measured quantity at the loading or discharge port as used to determine payments for the cargo. If the reporting party is unable to use shore measurements of the quantity, vessel measurements as determined by an independent inspection company (i.e. a U.S. Customs &BP-approved commercial gauger) with application of a Vessel Experience Factor (VEF), if determined to be valid (per API MPMS Chapter 17.9) and applicable must be used for emission calculation purposes.
(4) For quantities that are not sold or transferred but are subject to reporting under this rule, quantification methods that comply with appropriate procedures published by such industry consensus organizations as the American Society for Testing and Materials (ASTM) and the American Petroleum Institute (API) will be used to report.
(i) The documentation must include any calibration methods to be used to maintain measurement accuracy.
(ii) The documentation will include an estimate of the uncertainty of the quantity reported.
(b) If any separate adjustment of a reportable quantity transferred is made, a record of the adjustment, including the reason for the adjustment, must be made and the adjustment must be included in the reported total quantity.

134. For carbon content determination, a different method is proposed because samples stored for up to twelve months would probably deteriorate and be unrepresentative, as well as presenting a significant support burden on the reporting party. Attempting to composite dozens if not hundreds of samples following proper laboratory protocol is impractical. Most modern laboratories perform this by analyzing the individual samples and mathematically "compositing" the sample using the average or other appropriate techniques. It is further expected that most of the materials will tend to have carbon shares that are consistent over the year. Repeated sampling and analyses of these materials will not appreciably improve the accuracy of the CO_2 calculation while it does significantly increase the support burden.

API also recommends including a mechanism to reduce sampling and analyses of materials for which the previous analysis results have converged on a result that has sufficiently small variability that further testing would not appreciably change the carbon share calculation.

(c) For Calculation Methodology 2 of this subpart, samples of each petroleum product and natural gas liquid shall be taken at least monthly for the reporting year.
(1) The samples shall be tested using ASTM test methods for carbon share, as appropriate (see Technical Support Document).

(2) If the carbon content of the prior sample analysis for a material group has a one-sided, two standard deviation probability range of 1% of the average carbon share or less, sampling may be suspended for the remainder of the year for that material. Reporters must sample seasonal gasoline each month of the season. For materials whose analyzed carbon shares are not statistically different at the 95% confidence level, the reporter can choose to combine analytical results and use a common Emission Factor based on the combined dataset and sample the combined group as if a single product.

Sec. 98.395 Procedures for estimating missing data.

Whenever a quality-assured value of the quantity of petroleum products, natural gas liquids, biomass, or feedstocks during any period is unavailable, a substitute data value for the missing quantity measurement shall be used in the calculations contained in Sec. 98.393.

(a) The method, the calculations and input variables used to calculate the missing data must be supportable and/or documented.

(b) For imported and exported refined and semi-refined products, the estimated or calculated quantity may not be less than the quantity reflected in any financial transaction with a buyer or seller of the material for the period.

(c) For pipeline-imported and exported refined and semi-refined products, the last valid volume reading based on the company's established procedures for purposes of product tracking and billing shall be used. If the reporting period does not coincide with the company's established periods for financial reporting and the quantity for the reporting period requires estimation, the quantity reported shall be based on the amount prorated for the time in the period at the average flowrate during the prorated portion of the period.

(d) For refinery-imported and exported refined and semi-refined products, the last valid volume reading based on the company's established procedures for purposes of product tracking and billing shall be used. If the reporting period does not coincide with the company's established periods for financial reporting and the quantity for the reporting period requires estimation, the quantity reported shall be based on the amount prorated for the time in the period at the average rate of quantity change during the prorated portion of the period.

135. EPA in the preamble on page 16569 states: "*Petroleum products are ultimately consumed in one of two ways: Either through combustion for energy use, or through a non-energy use such as petrochemical feedstocks or lubricants. Combustion of petroleum products produces CO_2 and lesser amounts of CH_4 and N_2O, which are in almost all cases emitted directly into the atmosphere. Some non-energy uses of fuels, such as lubricants, also result in oxidation of carbon and CO_2 emissions. This process may occur immediately upon first use or, in the case of biological deterioration, over time. Carbon in other petroleum products, such as asphalts and durable plastics, may remain un-oxidized for long periods unless burned as fuel or incinerated as waste.*"

API comments: EPA provides a summary of emissions in the Technical Support Document on page 17, which shows asphalt contributes 0 emissions and waxes contribute 0.7% of the emissions of the source category. API recommends that: (1) asphalt should not be included because this material remains un-oxidized for long periods of time and EPA indicates that the emissions are 0; (2) durable plastics should not be included because they remain un-oxidized for long periods of time; and (3) waxes should not be included because they have minimal contribution (0.7% of the source category total).

136. Section 98.394 requires refineries and importers and exporters of petroleum products to measure the quantity of petroleum products, natural gas liquids, biomass, and all feedstocks using a flow meter or tank gauge that are calibrated according to the standards and methods referenced in the rule. Importers and exporters of record often do not own or operate the equipment used to transport or storage materials including flow meters and tank gauges. Instead the importer and exporter are contracted to handle the transfer of materials. The quantities of materials are measured under the Department of Homeland Security's Bureau of U.S. Customs & Border Protection (CBP), which has a rigorous program to ensure measurement accuracy. The CBP program also applies to some refinery feedstocks. Therefore, API suggests an alternative monitoring requirement be included in section 98.394 that allows refineries, importers and exporters to use quantities determined under the CBP program.

137. The Department of Homeland Security's Bureau of U.S. Customs & Border Protection (CBP) is the federal agency tasked with enforcing regulatory requirements around calculation of imported quantities of bulk petroleum feedstocks and products. 19 CFR§151 Examination, Sampling and Testing of Merchandise details the requirements and Subpart C of 19 CFR§151 deals specifically with petroleum and petroleum products.

For marine movements, third party gaugers bonded and approved by CBP's Laboratory and Scientific Services group are to be employed to objectively determine quantities of bulk petroleum materials being imported at refineries and chemical plants. Subpart C of 19 CFR§151 deals specifically with petroleum and petroleum products. Accuracy of the data is assured by the third party gauger, who is in turn approved by CBP prior to doing any marine measurement work. CBP periodically audits third party gaugers to ensure their practices and equipment are in accordance with industry requirements.

For pipeline movements into the United States, CBP requires that a custody transfer meter on the pipeline be determined, and the importer must certify to CBP that the meter was installed in accordance with API or ASTM guidelines, that the meter is proved/calibrated on a basis in accordance with its' usage and that records relating to the installation, care and operation of the meter are stored in an organized manner and available for CBP's review upon request. As the importer is often times not the owner/operator of the meter, contracts between the meter owner and the importer are sued to convey the requirements.

Also there are Foreign-Trade Zones (FTZs) that operate outside of the Customs Territory of the United States and as such, movements from FTZs by any mode of transportation into the United States are considered imports. All custody transfer points into and out of FTZ facilities must be maintained in accordance with API's Manual of Petroleum Measurement Standards (MPMS). Under that guideline, each refinery asserts to CBP that the custody transfer and measurement systems have been installed according to API MPMS or ASTM or manufacturer's guidelines, that said systems are being maintained and operated in accordance with those same guidelines, and that the records are being stored in an organized manner and are available for review by CBP.

Subpart NN - Natural Gas and Natural Gas Liquids (98.400)

a. EPA Requested Feedback

138. *EPA requests comment "on whether or not EPA should use the national inventory estimates of CH_4 and N_2O emissions from natural gas combustion, and apportion them to individual natural gas suppliers based on the quantity of their product." and EPA requests "comment on an approach in which natural gas suppliers would be required to develop facility- and batch-specific carbon contents through periodic sampling and analysis." (p. 16577)*

API Comment: As API has commented earlier in this document, EPA should rely on available information and reports and only gather the data necessary to fill gaps in this available information. Also , as API commented earlier in this document, NGL's destined for combustion use and hence emissions are a small subset of the entire spectrum and volume of NGL produced. API has suggested that EPA change the focus for reporting of NGL's to odorized propane, butane, or mixed propane/butane from fractionation facilities or blenders as these represent the only sources of NGL's destined for fuels. Given the small role that CH_4 and N_2O play in combustion CO_2 equivalents (<1%), API believes there is no value in batch- specific carbon content analysis and/or information.

b. Additional API comments

139. 98.401 states: *"Any supplier of natural gas and natural gas liquids that meets the requirements of § 98.2(a)(4) must report GHG emissions."* (16720).

API comments: § 98.2(a)(4) does not include a threshold for the amount of natural gas liquids a facility must produce in order to be subject to reporting. Many facilities produce small amounts of natural gas liquids would thus be subject to the reporting rule. API requests that a threshold for the amount of odorized propane and/or butane that is equivalent to 25,000 metric tonnes of CO_2 equivalency when combusted be included in the rule.

140. 98.402 states: *"(a) Natural gas processing plants must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, isobutane and bulk NGLs sold or delivered for use off site."*

API comments: EPA's requirements for reporting of "natural gas liquids" (NGL's) contained in Subparts MM and NN will result in significant "double counting" of NGL's and reporting of NGL's which are used for chemical feedstock and do not result in GHG emissions from their combustion. In fact, most of the NGL produced in the US or imported is used as feedstock rather than fuel – as noted in EPA's Technical Support Document. Odorized propane and/or butane are almost exclusively used for NGL based fuels and should be the focus of the rule rather than the broad production of all NGL's.

API suggests that reporting of NGL's be restricted to odorized propane and/or butane (or propane/butane mix) and that such reporting only be required from facilities which fractionate NGL's into their particular components, which are the only sources of fuel quality propane/butane, and blenders which odorize and sell propane/butane for fuel use. This will avoid the double counting of mixed NGL's which are subsequently fractionated at different facilities and reported a second (or perhaps third) time. It will also avoid the reporting of NGL's which are not suitable for or destined for fuel use and subsequent emissions.

141: The proposed rule's treatment of natural gas liquids (NGL) suppliers would dramatically overstate GHG emissions attributable to NGL consumption. EPA's approach to NGLs produced by domestic processors would also "double-count" the upstream emissions attributable to these products. Subpart NN would require domestic natural gas processors to specifically report emissions associated with the complete combustion of certain individual NGL products (propane, butane, ethane, and isobutene) as well as "bulk NGLs" (referring to undifferentiated mixtures of NGLs, excluding lease condensate). However, as in the petroleum products industry, domestic natural gas processors often produce semi-refined, *intermediate* NGL products (including bulk NGLs and "raw mix") that are delivered to other processors and fractionators for further processing and separation.

The magnitude of the double-counting that would occur under the proposed Subpart NN is significant. According to the most recent industry survey, there are 308 processing facilities in the U.S. that exclusively produce "raw mix" or bulk NGLs for further separation, with a total production of approximately 314 million barrels per year (47% of US NGL production). [10] These intermediate products have no market or use other than further separation. Rather, this product is sold to fractionators who separate the product into its constituent parts. It is these fractionators, rather than the producers of the raw make or Y-grade, Bulk NGL who would best know the end use of the products.

Without this change to the reporting of intermediate products, the proposed rule would count emissions from the same unit of production multiple times as it proceeds down the natural gas processing chain. This unnecessary double-counting should be avoided by eliminating reporting of bulk NGLs, and placing the reporting requirement on fractionators (who separate NGLs into their individual components, and are in the best position to know which NGLs will ultimately be combusted). Within the NGL supply chain, fractionators are the facilities most comparable to refiners (which bear the obligation of reporting upstream petroleum product emissions under the proposed Subpart MM) and LDCs (which bear the obligation of reporting upstream natural gas emissions under the proposed Subpart NN.

Proposed 40 CFR § 98.402(a) would require domestic natural gas processing facilities to report CO_2 emissions that would result from complete combustion of all NGLs produced at those facilities. In addition, proposed 40 CFR § 98.390(c) would require importers of petroleum products to report CO_2 emissions that would result from complete combustion of all NGLs introduced to the United States. However, as EPA recognizes in its TSD for Natural Gas Suppliers, an overwhelming proportion of NGLs produced or imported in the United States are not used as fuels – indeed, data from the American Petroleum Institute indicates that from 2000 to 2007, between 69.2% and 75.3% of all NGLs sold each year were used for *non*-fuel purposes. For example, ethane produced by fractionators is usually delivered as an input for the production of plastics. As EPA also recognizes, processors are usually not in a position to know the ultimate use or disposition of the NGLs they supply. The same is generally true of importers.

Given these facts, EPA should reconsider the "upstream" reporting approach it has adopted for NGLs, and instead place the reporting requirement on major entities which purchase or distribute

10 Gas Processing Survey, Oil & Gas Journal June 23, 2008.

NGLs for known, *combustive* end-uses. Fractionators are the most appropriate domestic reporting entity for this purpose, since fractionators often know the end-use associated with their products. Such an approach would provide EPA with a more accurate understanding of the contribution that NGLs make to nationwide GHG emissions. These combustion NGLs would likely also be reported by the combustor.

Suggested change regarding NGLs

> 40 CFR § 98.402(a) Natural gas processing plants must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, and isobutene ~~and bulk NGLs~~ sold or delivered for use off site..

142: The Agency takes a different but more effective approach in Sec. 98.404, (Subpart NN Natural Gas and Natural Gas Liquids) in the monitoring and QA/QC requirements for suppliers of natural gas and NGLs versus those provided in Subpart MM. In Subpart NN, EPA relies on "using any of the oil and gas flow meter test methods that are in common use in the industry and consistent with the Gas Processors Association Technical Manual and the American Gas association Gas Measurement Committee reports." This construction still has the problem that it limits the reporter to a very restricted set of standards from amongst several well respected organizations, but it does not trap the Agency into a role of specifying details that are not critical to the proposed rule's mission.

[Page 16721] Sec. 98.404 (NN) is a more readily implemented as written than Subpart MM, but it does have a problem in that it specifies two particular industry standards organizations out of several technically acceptable choices, and it presents methods for handling missing data which will eventually conflict with the quantities reported for other quality assured purposes. Specific revisions are suggested below.

Sec. 98.404 Monitoring and QA/QC requirements.

(a) The quantity of natural gas liquids and natural gas must be as recorded in the company's financial records and determined using any of the oil and gas flow meter test methods that are in common use in the industry and consistent with the Gas Processors Association (GPA), the American Gas Association (AGA), the American Petroleum Institute (API), ASTM International (ASTM), the American Society of Mechanical Engineers (ASME), or other industry consensus organizations.

(b) The minimum frequency of the measurements of quantities of natural gas liquids and natural gas shall be based on the company's standard practices for commercial operations. For natural gas liquids, these are measurements taken at custody transfers summed to the annual reportable volume. For natural gas, these are daily or more frequent totals of continuous measurements, and summed to the annual reportable volume.

(c) All flow meters and product- or fuel-composition monitors shall be calibrated or verified using a suitable method published by an industry consensus organization or the equipment manufacturer. Fuel flow meters or fuel composition monitors shall be recalibrated or reverified at an interval reflecting good commercial practice.

(d) *Reporter-specific emission factors or higher heating values shall be determined using industry standard practices such as, but not limited to, the American Gas Association (AGA), and the Gas Processors Association (GPA); and ASTM International (ASTM) for compositional analysis necessary for estimating CO_2 emission factors.*

Subpart PP - Suppliers of Carbon Dioxide (98.420)

a. EPA Requested Feedback

143. *EPA seeks "comment on the decision to exclude the reporting of fugitive CO_2 emissions from the carbon capture and storage chain […] there could be merit in requiring the reporting of fugitive emissions from geological sequestration of CO_2, in particular." (p. 16583)*
API comments: API supports the decision to exclude the reporting of fugitive CO_2 emissions from the CCS chain broadly and specifically does not believe there is merit in requiring the reporting of fugitive emissions from geologic sequestration of CO_2 or EOR operations that utilize CO_2. API is concerned however that EPA does not appear to have a clear understanding of the behavior of CO_2 when it is injected (usually in a supercritical state) into a geologic formation. EPA's discussion of the merits of reporting fugitive emissions from geologic sequestration suggests that EPA equates "retention rates" with only the volume of CO_2 that is locked in the geologic formation due to capillary trapping forces and that the remainder of the CO_2, the mobile portion, constitutes the potential fugitive emission.[11] This is incorrect.

Retention rate or storage rate should refer to the amount of CO_2 placed in a secure underground storage formation or that is used in an active EOR project at a given point in time. As noted in a previous comment, the CO_2 produced with the oil is recycled through the system; it is not lost to the atmosphere. Importantly, each time the CO_2 is cycled through the reservoir, additional CO_2 is added to supplement the recycled CO_2 to offset CO_2 trapped in the formation due to capillary forces and to replace displaced reservoir fluids, thus maintaining a constant injection volume at the EOR project.

The "retention rate" EPA refers to in the Preamble does not adequately capture the fact that EOR is a "closed system." In fact, the report that EPA cites in their discussion of retention rates recognizes this fact and states that, regarding a reservoir with 38% retention, "Essentially 100% of the purchased CO_2 is still in the system. At the end essentially 100% of the fluid will be stored in a reservoir." Additionally, evidence suggests that CO_2 injected via EOR wells in compliance with the UIC regulations does not leak into the surrounding groundwater (Smyth et al, 2008; Wilson and Monea, 2004) let alone the atmosphere (Klusman, 2003; Wilson and Monea, 2004).

References:
Smyth et al. (2008) *Update on Studies on Risk to Aquifers from CO_2 Sequestration* Gulf Coast Carbon Center, Bureau of Economic Geology. [SACROC EOR project]
Klusman, (2003*) A geochemical perspective and assessment of leakage potential for a mature carbon dioxide-enhanced oil recovery project and as a prototype for carbon dioxide*

[11] In particular, EPA states (74 FR 68 16584) "This report could provide information on the amount of CO2 sequestered based on the amount of CO2 injected minus any fugitive emissions)".

sequestration: Rangely field, Colorado. American Association of Petroleum Geologists Bulletin, 87(9), 1485-1507 [Rangely EOR project]
Wilson and Monea (editors) (2004) *IEA GHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-2004* Petroleum Technology Research Center, Regina SK, Canada. [Weyburn EOR project]

144. *EPA seeks comment on how to quantify and verify the amount of CO_2 sequestered in geologic formations*.
API comments: The information EPA is considering that all EOR operators submit, regardless of whether the operator is intending to store CO_2 or not, is unreasonable. EPA asks for data on fugitive emissions where there is no data to support the concept of fugitive emissions from an EOR site (see references above) nor are there technologies available to reliably measure soil/air fluxes (this was clearly established at the EPA public workshop on Underground Injection of CO_2 in Feb. 2008 in Arlington, VA). Moreover, many of the requests are well beyond the scope of this rulemaking, such as requiring *"a map showing the modeled aerial extent of the CO_2 plume over the lifetime of the project"* and *"providing information which demonstrates sufficient storage capacity for the expected operating lifetime of the plant"* (74 FR 68 16584)[12]. Currently, these are not requirements for Class II EOR wells, nor do they make any sense in a business-as-usual EOR context. Indeed, almost every item of requested information is not within scope of this rulemaking and is in fact being addressed to a large extent by the EPA's proposed CO_2 storage regulations. However, if EPA were to require submittal of this information – which API contends is not appropriate - and if the same information is required under another rule, compliance with the other rule should suffice for this rule.

Consistent with the above comments on EOR, API does not believe the reporting rule should include CO_2 managed by CCS, since the intent of the reporting rule is to gather CO_2 emissions data to inform policy. By definition, neither CCS nor EOR should be considered a GHG emission source. Based on extensive studies conducted to date (e.g., Weyburn CO_2 Monitoring Project, Saline Aquifer Carbon Dioxide Storage project (SACS), CO_2Store, etc.) the evidence is that there is no leakage associated with these types of operations (e.g. Weyburn, Sleipner, and In Salah). If in the future GHG reduction regulations are promulgated, offset credits should be granted to the quantity of CO_2 managed by an entity and tracked through the appropriate reporting mechanism.

145. *EPA seeks "comment on alternative methods for defining the reporting facility (e.g., reporting at the level of an individual well)." (p. 16585)*
API comments: EPA has correctly noted that defining the reporting facility as an individual well results in "*complex reporting requirements*" which "*are difficult to implement*" (74 FR 68 16531). Consistency with other EPA rulemakings efforts should be followed here by allowing the combining of individual units or components which are under common control, dependent upon and directly adjacent to the facility (i.e., CO_2 production well). This should be allowed to simplify reporting to the extent practical.

[12] The phrase "*of the plant*" begs the question, what plant? These are EOR facilities being discussed. Also, why would a regulatory agency - in its data collecting function -need to know whether there is sufficient storage capacity? This should be covered – if at all, and there are compelling reasons why not – by the proposed Class VI rules, not a reporting rule.

146. *EPA has concluded that reporting the volume of the CO_2 streams from CO_2 production wells is important given the large fraction of CO_2 supplied from CO_2 production wells. Further, EPA concludes that there is minimal burden associated with these requirements, as all necessary monitoring equipment should already be installed to support current operating practice.*
API comments: EPA is correct that a large portion of CO_2 supplied comes from CO_2 production wells. However, according to EPA's *Inventory of US GHG Emissions and Sinks: 1990-2006*, only 5% of produced CO_2 was used in non-EOR applications and possibly released. The rest was used in EOR and is not emitted to the atmosphere (as recognized by EPA's methodology – "The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered." Box 3-3). Additionally, whether or not equipment is installed is not a reasonable basis for imposing reporting requirements. The basis for reporting GHG under this rule should be the potential for release to the atmosphere. Given these two realities, reporting the volume of CO_2 from production wells should not be required.

147. Although EPA is not proposing inclusion of geologic sequestration, they are asking for comments for this relatively small source to *"provide a more complete understanding of the efficacy of carbon capture and storage technologies as an option for mitigating CO_2 emissions"* and to *"quantify and verify the amount of CO_2 sequestered in geologic formations."* EPA notes that *"a possible approach to include geologic sequestration might be to ask EOR operators to submit a geologic sequestration report […] based on the amount of CO_2 injected minus any fugitive emissions."* EPA goes on to identify a list of specific information to be included in the report.
API comments: EOR cannot be confused with sequestration. EOR accounts for a relatively small percentage of emissions; requiring reporting from EOR places undue burden on operations that might not be subject to the rule otherwise. The following comments are specific to the reporting elements EPA outlines in the preamble:

- There are not "sequestration sites"; the distinction relative to EOR projects (e.g. for demonstration for sufficient storage) should be reinforced.
- Requiring EOR operators to submit a geologic sequestration report would require tracking and identifying emission sources which may not be subject to the rule otherwise.
- Some of the data to be included in the report (e.g. a map showing the modeled aerial extent of the CO_2 plume over the lifetime of the project) is CBI, and is not relevant to emissions reporting.
- Certain requirements (e.g. assessment of the risks of CO_2 leakage) extend beyond the scope of rulemaking for emission sources operated in normal process.
- Requirements surrounding 'baseline conditions' are misplaced. There were likely no baseline conditions established for existing EOR projects. Effectiveness of the system to contain CO_2 may have been based on modeling and/or pilots within the field.

b. Additional API Comments

148. EPA concluded that *"all facilities capturing CO_2 would likely already exceed the reporting thresholds under other subparts of proposed 40 CFR part 98 for their downstream emissions. Therefore, a proposed threshold of 'All In' for reporting CO_2 supply from industrial facilities or process units would not bring in additional facilities not already triggering other subparts of the proposed rule."*

API Comment: API disagrees with the assertion that all facilities capturing CO_2 would exceed the reporting threshold of 25,000 tonnes emissions. For example, a small gas plant with mostly electric compression would likely not exceed 25,000 tonnes and easily could be a supplier of CO_2.

149. § 98.420 Definition of the source category.

a)(1) Production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications.

(a)(2) Facilities with CO_2 production wells.

API Comment: EPA should not require reporting for either of these categories if the CO_2 is used for EOR operations, which are "closed systems". It is unclear – and EPA offers no explanation – of how collecting information on CO_2 production will "assist EPA and others in developing future climate policy" (74 FR 68, page 16456).

The captured or produced CO_2 utilized in EOR operations is transported to an oil field where it is injected into a hydrocarbon reservoir. A significant fraction (about 1/3) of the CO_2 will be trapped in the hydrocarbon formation due to capillary forces. The remainder moves through the reservoir, mixing with and mobilizing the oil. The CO_2 produced with the hydrocarbons is separated, recovered, compressed, and re-injected into the hydrocarbon formation. EPA's own methodology recognizes that the CO_2 is managed within a closed system and therefore not released into the atmosphere – "The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered." Box 3-3 of EPA's *Inventory of US GHG Emissions and Sinks: 1990-2006*).

150. § 98.424 *Monitoring and QA/QC requirements*

(a) Facilities with production process units that capture CO_2 stream must measure on a quarterly basis using a mass flow meter….

(b) *CO_2 production well facilities must measure on a quarterly basis…using a mass flow meter*….

API comments: Mass flow meters of greater than 3" diameter capable of dense-phase CO_2 measurement (i.e., large meters that might be required for the measurements anticipated by EPA) are not yet available. Indeed, the technology appears only to be emergent and is by no means proven. Contrary to EPA's assertion that "these sites likely already have the necessary flow meters installed to monitor the CO_2 stream" (74 FR 68 16585), volumetric measurements converted to mass flow rates have been used for over 30 years for custody transfers between parties. Accordingly, CO_2 suppliers should be offered the flexibility to utilize any suitable measurement device (which would allow for the adoption of mass flow meters when the technology has been proven).

151. § 98.425: The rule proposes that facilities with missing data on the composition of the CO_2 stream captured, extracted, imported, and exported "*should use the quarterly or average value for the parameter from the past calendar year*". Every facility's fuel measurement is unique based upon equipment configuration and type. Missing data should be addressed in the QAPP, not prescribed in the rule.

155. Sequestration of CO_2 streams (carbon capture and sequestration or CCS) is one of the technologies that can be used to reduce CO_2 emissions. Consistent with the above comments on

EOR, API does not believe the reporting rule should include CO_2 managed by CCS since the intent of the reporting rule is to gather CO_2 emissions data to inform policy. If in the future GHG reduction regulations are promulgated, offset credits should be granted to the quantity of CO_2 managed by an entity and tracked through the appropriate reporting mechanism.

Appendix A

Standards for Measuring Quantities
Applicable to
EPA Proposed MRR of Greenhouse Gas Emissions

The references to standards provided in the proposed rule for measuring quantities of hydrocarbons (including petroleum products, natural gas liquids, biomass, and all feedstocks) are incomplete and some are outdated. It may not be effective or efficient for EPA to reference specific measurement standards and specific editions of those standards as a comprehensive list would require considerable resources for maintenance and updating. Below is a list of over 300 hydrocarbon measurement standards used to measure quantities of petroleum products and natural gas liquids. Entire series of standards from particular standards developers are listed as many of the standards are inter-related and have to be used in conjunction with one another for measurement of quantities. However, this list does not comprise an exhaustive list of all standards that should be individually referenced in the proposed rule.

API Manual of Petroleum Measurement Standards (MPMS)

Chapter 1	Vocabulary
Chapter 2.2A	Measurement and Calibration of Upright Cylindrical Tanks by the Manual Strapping Method

[Chapter 2.2A should be used in conjunction with Chapter 2.2B. These two standards combined supersede the previous API Standard 2550, *Measurement and Calibration of Upright Cylindrical Tanks*]

Chapter 2.2B	Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method
Chapter 2.2C	Calibration of Upright Cylindrical Tanks Using the Optical-Triangulation Method
Chapter 2.2D	Calibration of Upright Cylindrical Tanks Using the Internal Electro-optical Distance Ranging Method
Chapter 2.2E	Petroleum and Liquid Petroleum Products—Calibration of Horizontal Cylindrical Tanks—Part 1: Manual Methods
Chapter 2.2F	Petroleum and Liquid Petroleum Products—Calibration of Horizontal Cylindrical Tanks—Part 2: Internal Electro-optical Distance-ranging Method
Std 2552	Measurement and Calibration of Spheres and Spheroids
Std 2554	Measurement and Calibration of Tank Cars
Std 2555	Liquid Calibration of Tanks
RP 2556	Correcting Gauge Tables for Incrustation
Chapter 2.7	Calibration of Barge Tanks
Chapter 2.8A	Calibration of Tanks on Ships and Oceangoing Barges
Chapter 2.8B	Establishment of the Location of the Reference Gauge Point and the Gauge Height of Tanks on Marine Tank Vessels
Chapter 3.1A	Standard Practice for the Manual Gauging of Petroleum and Petroleum Products
Chapter 3.1B	Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging
Chapter 3.2	Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars
Chapter 3.3	Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging

Chapter 3.4	Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging
Chapter 3.5	Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging
Chapter 3.6	Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems
Chapter 4.1	Proving Systems – Introduction
Chapter 4.2	Displacement Provers
Chapter 4.4	Tank Provers
Chapter 4.5	Master-Meter Provers
Chapter 4.6	Pulse Interpolation
Chapter 4.7	Field-Standard Test Measures
Chapter 4.8	Operation of Proving Systems
Chapter 4.9.1	Methods of Calibration for Displacement and Volumetric Tank Provers, Part 1—Introduction to the Determination of the Volume of Displacement and Tank Provers
Chapter 4.9.2	Methods of Calibration for Displacement and Volumetric Tank Provers, Part 2—Determination of the Volume of Displacement and Tank
Chapter 5.1	General Consideration for Measurement by Meters
Chapter 5.2	Measurement of Liquid Hydrocarbons by Displacement Meters
Chapter 5.3	Measurement of Liquid Hydrocarbons by Turbine Meters
Chapter 5.4	Accessory Equipment for Liquid Meters
Chapter 5.5	Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems
Chapter 5.6	Measurement of Liquid Hydrocarbons by Coriolis Meters
Chapter 5.8	Measurement of Liquid Hydrocarbons by Ultrasonic Flowmeters Using Transit Time Technology
Draft Standard	Vortex Shedding Flowmeter for Measurement of Hydrocarbon Fluids
Chapter 6.1	Lease Automatic Custody Transfer (LACT) Systems
Chapter 6.2	Loading Rack Metering Systems
Chapter 6.4	Metering Systems for Aviation Fueling Facilities
Chapter 6.5	Metering Systems for Loading and Unloading Marine Bulk Carriers
Chapter 6.6	Pipeline Metering Systems
Chapter 6.7	Metering Viscous Hydrocarbons
Chapter 7	Temperature Determination
Chapter 8.1	Manual Sampling of Petroleum and Petroleum Products
Chapter 8.2	Automatic Sampling of Petroleum and Petroleum Products
Chapter 8.3	Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products
Chapter 8.4	Standard Practice for Sampling and Handling of Fuels for Volatility Measurement
Chapter 9.1	Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
Chapter 9.2	Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer
Chapter 9.3	Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method
Chapter 10.1	Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method
Chapter 10.2	Determination of Water in Crude Oil by Distillation

Chapter 10.3	Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure)
Chapter 10.4	Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure)
Chapter 10.5	Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation
Chapter 10.6	Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)
Chapter 10.7	Standard Test Method for Water in Crude Oils by Potentiometric Karl Fischer Titration
Chapter 10.8	Standard Test Method for Sediment in Crude Oil by Membrane Filtration
Chapter 10.9	Standard Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration
Chapter 11.1	Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils
Chapter 11.2.2	Compressibility Factors for Hydrocarbons: 0.350 – 0.637 Relative Density (60 °F/60 °F) and –50 °F to 140 °F Metering Temperature
Chapter 11.2.2M	Compressibility Factors for Hydrocarbons: 350 – 637 Kilograms per Cubic Meter Density (15 °C) and –46 °C to 60 °C Metering Temperature
Chapter 11.2.4	Temperature Correction for the Volume of NGL and LPG Tables 23E, 24E, 53E, 54E, 59E, 60E
Chapter 11.2.5	A Simplified Vapor Pressure Correlation for Commercial NGLs
Chapter 11.3.2.1	Ethylene Density
Chapter 11.3.3.2	Propylene Compressibility
Chapter 11.4.1	Properties of Reference Materials, Part 1—Density of Water and Water Volume Correction Factors for Calibration of Volumetric Provers
Chapter 11.5.1	Density/Weight/Volume Intraconversion, Part 1—Conversions of API Gravity at 60 °F
Chapter 11.5.2	Density/Weight/Volume Intraconversion, Part 2—Conversions for Relative Density (60/60 °F)
Chapter 11.5.3	Density/Weight/Volume Intraconversion, Part 3—Conversions for Absolute Density at 15 °C
Chapter 12.1.1	Calculation of Static Petroleum Quantities, Part 1—Upright Cylindrical Tanks and Marine Vessels
Chapter 12.1.2	Calculation of Static Petroleum Quantities, Part 2—Calculation Procedures for Tank Cars
Chapter 12.2	Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters
Chapter 12.2.1	Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volume Correction Factors, Part 1—Introduction
Chapter 12.2.2	Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2—Measurement Tickets
Chapter 12.2.3	Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 3—Proving Reports
Chapter 12.2.4	Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 4—Calculation of Base Prover Volumes by Waterdraw Method

Chapter 12.2.5	Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 5—Base Prover Volume Using Master Meter Method
Chapter 12.3	Calculation of Volumetric Shrinkage From Blending Light Hydrocarbons with Crude Oil
Chapter 13.1	Statistical Concepts and Procedures in Measurement
Chapter 13.2	Statistical Methods of Evaluating Meter Proving Data
Chapter 14.1	Collecting and Handling of Natural Gas Samples for Custody Transfer
Chapter 14.2	Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases
Chapter 14.3.1	Concentric, Square-edged Orifice Meters, Part 1—General Equations and Uncertainty Guidelines
Chapter 14.3.2	Concentric, Square-Edged Orifice Meters, Part 2—Specification and Installation Requirements
Chapter 14.3.3	Concentric, Square-Edged Orifice Meters, Part 3—Natural Gas Applications
Chapter 14.3.4	Concentric, Square-Edged Orifice Meters, Part 4—Background, Development, Implementation Procedures and Subroutine Documentation
Chapter 14.4	Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes
Chapter 14.5	Calculation of Gross Heating Value, Specific Gravity, and Compressibility of Natural Gas Mixtures from Compositional Analysis
Chapter 14.6	Continuous Density Measurement
Chapter 14.7	Mass Measurement of Natural Gas Liquids
Chapter 14.8	Liquefied Petroleum Gas Measurement
Chapter 14.9	Measurement of Natural Gas by Coriolis Meter
Chapter 14.10	Measurement of Flow to Flares
Chapter 15	Guidelines for Use of the International System of Units (SI) in the Petroleum and Allied Industries
Chapter 16.2	Mass Measurement of Liquid Hydrocarbons in Vertical Cylindrical Storage Tanks by Hydrostatic Tank Gauging
Chapter 17.1	Guidelines for Marine Cargo Inspection
Chapter 17.2	Measurement of Cargoes on Board Tank Vessels
Chapter 17.3	Guidelines for Identification of the Source of Free Waters Associated With Marine Petroleum Cargo Movements
Chapter 17.4	Method for Quantification of Small Volumes on Marine Vessels (OBQ/ROB)
Chapter 17.5	Guidelines for Cargo Analysis and Reconciliation
Chapter 17.6	Guidelines for Determining Fullness of Pipelines Between Vessels and Shore Tanks
Chapter 17.7	Recommended Practices for Developing Barge Control Factors (Volume Ratio)
Chapter 17.8	Guidelines for Pre-Loading Inspection of Marine Vessel Cargo Tanks
Chapter 17.9	Vessel Experience Factor (VEF)
Chapter 17.10.2	Measurement of Refrigerated and/or Pressurized Cargoes on Board Marine Gas Carriers, Part 2—Liquefied Petroleum and Chemical Gases
Chapter 17.11	Measurement and Sampling of Cargoes on Board Tank Vessels Using Closed and Restricted Equipment
Chapter 17.12	Procedure for Bulk Liquid Chemical Cargo Inspection by Cargo Inspectors
Chapter 18.1	Measurement Procedures for Crude Oil Gathered From Small Tanks by Truck
Publ 2514A	Atmospheric Hydrocarbon Emissions from Marine Vessel Transfer Operations

Publ 2524	Impact Assessment of New Data on the Validity of American Petroleum Institute Marine Transfer Operation Emission Factors
Publ 2558	Wind Tunnel Testing of External Floating-Roof Storage Tanks
TR 2567	Evaporative Loss from Storage Tank Floating Roof Landings
TR 2568	Evaporative Loss from the Cleaning of Storage Tanks
TR 2569	Evaporative Loss from Closed-vent Internal Floating-roof Storage Tanks
Chapter 19.1	Evaporative Loss From Fixed-roof Tanks
Chapter 19.1A	Evaporation Loss From Low-pressure Tanks
Chapter 19.1D	Documentation File for API Manual of Petroleum Measurement Standards Chapter 19.1 "Evaporative Loss From Fixed-roof Tanks"
Chapter 19.2	Evaporative Loss From Floating-roof Tanks
Chapter 19.3, Part A	Wind Tunnel Test Method for the Measurement of Deck-fitting Loss Factors for External Floating-roof Tanks
Chapter 19.3, Part B	Air Concentration Test Method—Rim-seal Loss Factors for Floating-roof Tanks
Chapter 19.3, Part C	Weight Loss Test Method for the Measurement of Rim-seal Loss Factors for Internal Floating-roof Tanks
Chapter 19.3, Part D	Fugitive Emission Test Method for the Measurement of Deck-seam Loss Factors for Internal Floating-roof Tanks
Chapter 19.3, Part E	Weight Loss Test Method for the Measurement of Deck-fitting Loss Factors for Internal Floating-roof Tanks
Chapter 19.3, Part F	Evaporative Loss Factor for Storage Tanks Certification Program
Chapter 19.3, Part G	Certified Loss Factor Testing Laboratory Registration
Chapter 19.3, Part H	Tank Seals and Fittings Certification—Administration
Chapter 19.4	Recommended Practice for Speciation of Evaporative Losses
Chapter 20.1	Allocation Measurement
RP 85	Use of Subsea Wet-gas Flowmeters in Allocation Measurement Systems
RP 86	Recommended Practice for Measurement of Multiphase Flow
RP 87	Recommended Practice for Field Analysis of Crude Oil Samples Containing from Two to Fifty Percent Water by Volume
Chapter 21.1	Electronic Gas Measurement
Chapter 21.2	Flow Measurement—Electronic Liquid Measurement
Chapter 21.2-A1	Addendum 1 to Flow Measurement Using Electronic Metering Systems
Chapter 22.1	Testing Protocols—General Guidelines for Developing Testing Protocols for Devices Used in the Measurement of Hydrocarbon Fluids
Chapter 22.2	Testing Protocols—Differential Pressure Flow Measurement Devices
Std 2560	Reconciliation of Liquid Pipeline Quantities
Publ 2566	State of the Art Multiphase Flow Metering

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ISO 5167-4:2003	Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full — Part 4: Venturi tubes
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ASTM International

ASTM D4057	Standard Practice for Manual Sampling of Petroleum and Petroleum Products
ASTM D4177	Standard Practice for Automatic Sampling of Petroleum and Petroleum Products
ASTM D1298	Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1657	Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer
ASTM D4052	Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter
ASTM D4002	Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer
ASTM D473	Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method
ASTM D4006	Standard Test Method for Water in Crude Oil by Distillation
ASTM D4007	Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure)
ASTM D95	Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation
ASTM D1796	Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)
ASTM D4377	Standard Test Method for Water in Crude Oils by Potentiometric Karl Fischer Titration
ASTM D4807	Standard Test Method for Sediment in Crude Oil by Membrane Filtration
ASTM D4928	Standard Test Methods for Water in Crude Oils by Coulometric Karl Fischer Titration
ASTM D6304	Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fischer Titration
ASTM D71	Standard Test Method for Relative Density of Solid Pitch and Asphalt (Displacement Method)

ASTM D287	Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)
ASTM D1070	Standard Test Methods for Relative Density of Gaseous Fuels
ASTM D1217	Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer
ASTM D1480	Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer
ASTM D1481	Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer
ASTM D1550	Standard ASTM Butadiene Measurement Tables
ASTM D1555	Standard Test Method for Calculation of Volume and Weight of Industrial Aromatic Hydrocarbons and Cyclohexane
ASTM D2320	Standard Test Method for Density (Relative Density) of Solid Pitch (Pycnometer Method)
ASTM D2638	Standard Test Method for Real Density of Calcined Petroleum Coke by Helium Pycnometer
ASTM D2962	Standard Test Method for Calculating Volume-Temperature Correction For Coal-Tar Pitches
ASTM D3142	Standard Test Method for Specific Gravity, API Gravity, or Density of Cutback Asphalts by Hydrometer Method
ASTM D3505	Standard Test Method for Density or Relative Density of Pure Liquid Chemicals
ASTM D4311	Standard Practice for Determining Asphalt Volume Correction to a Base Temperature
ASTM D4292	Standard Test Method for Determination of Vibrated Bulk Density of Calcined Petroleum Coke
ASTM D4892	Standard Test Method for Density of Solid Pitch (Helium Pycnometer Method)
ASTM D5002	Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer
ASTM D5004	Standard Test Method for Real Density of Calcined Petroleum Coke by Xylene Displacement
ASTM D7042	Standard Test Method for Dynamic Viscosity and Density of Liquids by Stabinger Viscometer (and the Calculation of Kinematic Viscosity)
ASTM D7454	Standard Test Method for Determination of Vibrated Bulk Density of Calcined Petroleum Coke using a Semi-Automated Apparatus

GPA

GPA Technical Standards Manual

GPA RB 101-43	Compression and Charcoal Tests for Determining the Natural Gasoline Content of Natural Gas
GPA RB 181-86	Heating Value-Basis for Custody Transfer
GPA RB 194-94	Tentative NGL Loading Practices
GPA 1167	GPA Glossary—Definition of Words and Terms Used in the Gas Processing Industry
GPA 2103	Tentative Method for the Analysis of Natural Gas Condensate Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography
GPA 2145	Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry
GPA 2166	Obtaining Natural Gas Samples for Analysis by Gas Chromatography
GPA 2172	Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer

GPA 2174	Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography
GPA 2177	Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography
GPA 2186	Method for the Extended Analysis of Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Temperature Programmed Gas Chromatography
GPA 2377	Test for Hydrogen Sulfide & Carbon Dioxide in Natural Gas Using Stain Tubes
GPA 8173	Methods for Converting Mass Natural Gas Liquids and Vapor to Equivalent Liquid Volumes
GPA 8182	Standard for Mass Measurement of Natural Gas Liquids
GPA 8186	Measurement of Liquid Hydrocarbon by Truck Scales
GPA 8195	Tentative Standard for Converting Net Vapor Space Volumes to Equivalent Liquid Volumes
GPA TP-27	Temperature Correction for the Volume of NGL and LPG Tables 23E, 24E, 53E, 54E, 59E & 60E

AGA

AGA Report No. 3	Orifice Metering of Natural Gas, Part 1: General Equations & Uncertainty Guidelines
AGA Report No. 3	Orifice Metering of Natural Gas, Part 2: Specification and Installation Requirements
AGA Report No. 3	Orifice Metering of Natural Gas, Part 3: Natural Gas Applications
AGA Report No. 3	Orifice Metering of Natural Gas, Part 4: Background, Development Implementation Procedure
AGA Report No. 4A	Natural Gas Contract Measurement and Quality Clauses
AGA Report No. 5	Fuel Gas Energy Metering
AGA Report No. 7	Measurement of Natural Gas by Turbine Meter
AGA Report No. 8	Compressibility Factor of Natural Gas and Related Hydrocarbon Gases
AGA Report No. 9	Measurement of Gas by Multipath Ultrasonic Meters
AGA Report No. 10	Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases
AGA Report No. 11	Measurement of Natural Gas by Coriolis Meter