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Clerk of the Board

Air Resources Board

1001 I Street

Sacramento, California 95814

Re: Notice of Public Hearing to Consider Adoption of a Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Dear Air Resource Board Members:

The American Petroleum Institute (API) appreciates the opportunity to offer input to the California Air Resources Board (CARB) on the Draft Regulation on Mandatory GHG Reporting that was released by the ARB staff on October 19, 2007, and discussed during the public workshop on October 31, 2007.

API represents about 400 companies involved in all aspects of the oil and natural gas industry throughout the USA and globally. API works in close cooperation with local petroleum industry associations, such as the Western States Petroleum Association (WSPA), to advance issues that are of regional, national, and international significance.

As previously communicated to CARB, API has an extensive record of ongoing activities in the area of GHG Emissions Estimation and Reporting, having been active in this arena for nearly a decade. API-related guidelines are frequently used worldwide for developing and reporting corporate emission inventories for the oil and natural gas industry sectors[1,2]. API (jointly with International Petroleum Industry Environmental Conservation Association, IPIECA) recently augmented this guidance with the release of guidelines for GHG reduction projects[3]. Additionally, API and its member companies have participated as authors and expert reviewers on many other

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[1] API/IPIECA/OGP, Petroleum Industry Guidelines for Reporting Greenhouse Gas (GHG) Emissions (December 2003);
[2] API, *Compendium of GHG Emissions Methodology for the Oil & Gas Industry* (February 2004, addendum February 2005);
[3] API/IPIECA, Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects (March 2007)

reporting initiatives, guidelines and standards, including the IPCC 2006 Guidelines for National Inventories, the ISO international standard on GHG reporting and verification (ISO 14064), the US DOE Voluntary 1605(b) GHG Registry, the California Climate Action Registry, and the EU Emissions Trading System (EU-ETS).

WSPA and its members are best equipped to address specific issues related to the design of the mandatory reporting program pursuant to Assembly Bill 32 (AB32). WSPA and API have overlapping membership and the two associations work closely on common issues, and WSPA is taking the lead on commenting on the details of the California program from the California facilities' perspective.

API would like to offer a few comments below, focusing on a few overarching issues that have implications beyond California and its mandatory reporting regulation. Further comments on specific technical issues are provided in Attachment A.

I. ***Defining a deMinimis emissions level and an associated emission CAP***. API welcomes the addition of a deMinimis emissions level to the October 19th Draft of the Mandatory Greenhouse Gas Reporting Regulation. This is consistent with other national programs such as the U.S. DOE Voluntary GHG Reporting and Registry (also known as the 1605(b) Registry), and The Climate Registry (TCR). The TRC, as a consortium of over 40 states (including California), tribes and Canadian provinces, which aims to develop a uniform platform for reporting and archiving GHG data nationwide.

    ARB's introduction of a 10,000 tonnes CO2-E emissions CAP along with the newly defined 3% deMinimis level, negates this attempt at national harmonization, as neither TCR nor the US DOE reporting protocols have imposed such a CAP. Based on API's experience, petroleum refineries as well as oil & gas operations consist of an array of small sources with emissions that are not significant in the context of overall emissions from petroleum refineries and combined heat and power facilities. These types of facilities may encompass a large number of processing equipment and miles of pipelines, where the burden of merely tracking all these individual sources, and providing a "best estimate" of emissions, is significant. For a facility with total emissions in excess of 1.0 million tonnes of CO2-E, the "10,000 tonnes or less" requirement would effectively be equivalent to requiring an overall accuracy of determination that is less than 1%, which is beyond the accuracy and uncertainty ability of current quantification methodology.

    Therefore, API contends that imposing a 10,000 tonnes CO2-E CAP on the 3% threshold is arbitrary and it is not clear how it will be possible to implement in practice at petroleum refineries and Oil & Gas operations.

II. ***The role of equity reporting***. The Petroleum Industry Greenhouse Gas Reporting Guidelines (IPIECA, 2003) provide the flexibility for corporations (legal entities) to define themselves either in terms of Operational Control or by Equity Share. Companies operating in the general sector known as the petroleum (or oil & natural gas) industry come in a wide-variety of sizes, complexity and organizational structures and operations are commonly conducted by two or more parties working together in joint ventures, instead of by individual firms. These ventures take a variety of legal forms, and may or may not be established as separate legal entities.

For voluntary reporting initiatives, an 'Operational Control Basis' is consistent with the responsibility for day-to-day operations and implementation of Health, Safety and Environmental programs at operated facilities. Conversely, the Equity Share approach is compatible with the way financial statements are constructed, and is applicable to corporations risk assessment and shareholders disclosure for entity-wide reporting. The two approaches are broadly applicable at the entity level but based on experience by many multinational corporations the two systems cannot be overlaid on a facility-by-facility basis.

In the October 19th Draft Regulation, ARB stipulates that in addition to implementing the mandatory reporting requirements at the facilities under operational control, parent companies should provide an indication of their ownership share and operational control for each facility in the state. API contends that this requirement is extremely burdensome, and would not contribute to the accuracy of the reported emissions data. Requiring information on ownership structure and equity share for reporting facilities only serves to burden and confuse the reporters who ultimately might potentially incur the risk of divulging confidential business information.

If Equity Share information becomes an important consideration for the design of a future emissions trading system, or similar measures, a carefully considered approach should be developed at that time, and incorporated into future rules that would govern such measures. As it stands right now, API does not see any merit in adding this requirement to a mandatory reporting rule that has the 'facility' on an 'as operated basis' as the point of compliance.

III. ***Flexibility in light of methods complexity***. The Draft regulations provide a large volume of technical details for the computation of GHG emissions from industry facilities. These calculations are highly complex, with multiple unit conversions that are somewhat arcane and at times confusing. In recognition of the fact that errors might creep into equations and definitions, it is advisable to provide some flexibility to allow facility operators to bring forward alternative emission calculation methodology not specified by the ARB rule.

Attachment E of the staff report describes such flexibility by using a decision tree approach for stepping through the hierarchy of applicable methods with reference to facility circumstances and availability of appropriate data. This approach is similar to the framework recommended by the API Compendium, and has been used for development of corporate emission inventories worldwide. Despite that, the regulatory language of the Draft rule does not retain this flexibility but is rather rigid in its specification of calculation equations, default values, and measurement methods. It does not include the opportunity for either lessening the burden on reporters that could demonstrate the validity of alternative methods, or the ability to bring forward emerging new methodologies, It has been API and its members experience through the years that alternative emission calculations and measurement methods, which are not initially specified in regulations, evolve with time and a mechanism ought to be established to allow the introduction of new techniques that have the potential to improve the accuracy of the data reported. Such an approach is common in national USEPA regulations allowing the petitioning of the administrator for approval of alternative methods.

IV. ***Specification of standard conditions***. The equations used in the October 19th Draft for calculating emissions from Petroleum Refineries sources and for Oil & Gas operations have “hardwired” into them a molar volume conversion factor that is applicable for temperature and pressure conditions of 20C and 1atm. This is in contrast with the industry standard conditions of 60F (~ 15C) and 1atm. These industry standard conditions are used throughout the U.S. in ASTM standards and in specifications for petroleum and natural gas transmission and distribution, as defined in section 3.5 of the API Compendium (February 2004).

Under the standard conditions specified in the API Compendium the molar conversion factor is 379.3 scf/lb-mole (or 834.5 scf/Kg-mole) vs. the one specified in the ARB Draft rule, namely 849.5 scf/Kg-mole. While the difference between the two molar conversion factors is only about 2%, the proper implementation of the ARB equations will require industry reporters to convert all their existing volumetric measurements and instrument calibrations to the new set of temperature and pressure conditions, which is burdensome and does not serve a real purpose of improving the calculations. Conversely, the element of confusion it introduces could lead to erroneous calculations as these conversions might not be performed, or miscalculated. The bottom line is that as long as all reporters use a consistent set of units and conversion factors throughout their calculations, the final outcome in terms of total emissions, or metric tonnes of CO2-E will be identical.

API has found out from experience that imposing two sets of conditions is an opening for the introduction of errors into the calculation and for creating a lot of confusion and unnecessary work. Therefore in its GHG Compendium, API has taken the approach of writing the equations in generic terms and then providing “look-up” tables for the applicable constants in various sets of useful units to accommodate different practices for standards designation in other parts of the world. API recommends that the ARB adopt a similar approach and consult with its measurement experts that can provide the needed conversion factors in multiple sets of units and make them available with the rule in order to avoid potential errors and minimize burden on reporters.

V. ***Integrity of verification program***. One of the key features of the ARB mandatory reporting program is its reliance on a ‘Third-Party Verification’ process to validate methods used and verify the emissions reported. This is a feature that currently exists in several voluntary programs as well as in the EU-ETS system. Since many other states around the U.S. and others around the world are looking at the California program in order to learn and emulate it, it is important that the State Verification program stays intact as a statewide program. In this era of potentially global frameworks for addressing climate change mitigation, harmonization of systems is crucial. Availability of such a statewide uniform program will be essential to California's ability to trade emissions across the U.S. and globally.

API recommends that the verification program be structured and controlled at the state level, and be consistent with applicable ISO standards, such as ISO 14064.3 and 14065. In no case should the program be perceived as having a conflict between regulatory enforcement activity and commercial third party verification, as is practiced around the world. API is concerned that the use of Air Districts as verifiers will stifle the flow of information necessary for conducting verification.

API welcomes this opportunity to provide these general comments in an attempt to improve and streamline rule implementation. API views this rule as pivotal and trendsetting for other jurisdictions and would welcome continued discussion with the ARB on these matters. At the same time API is also continuing its multi-prong program of activities to improve GHG emissions estimation and reporting for the industry sector operations, by launching a revision of its GHG Compendium and addressing the accuracy and uncertainty of GHG emissions data in collaboration with other global peer associations.

Please do not hesitate to contact me directly if further information or clarifications are required on any of these issues.

Sincerely,

Karin Ritter

Attachment

ATTACHMENT A

Implementation of LDAR Programs at Refines - Section 95113(c)(4):

The draft rule requires using a screening value correlation approach for estimating fugitive emissions from equipment leaks. Refineries have used this general approach for many years to determine fugitive emissions of volatile organic compounds (VOCs) from those refinery streams in which the VOC content exceeds 10%. The data collection and record keeping required to apply this approach to CH_4 is significant compared to the negligible contribution of these emissions to the overall emissions data.

API has previously provided to ARB staff a report documenting results from a quantitative assessment of fugitive CH4 emissions at refineries. Those emissions were estimated based on counts of component in natural gas and refinery fuel gas service and average emission factor for gas service for the oil and gas industry. The estimated methane fugitive emissions were shown to represent about 0.11% of the total GHG inventory for a small/simple refinery and about 0.19% of the GHG inventory for a large/complex refinery.

Additionally, the way the rule describes how to implement the CAPCOA method - cited in the Draft rule - is erroneous. The method cited, which is known as the “correlation equation approach” was developed by CAPCOA after the completion and the issuance of the EPA 1995 Equipment Leaks Protocol, which incorporates all the industry data provided to the USEPA by API following the completion of major API/WSPA studies in the early 1990s that were conducted collaboratively with regulatory and enforcement personnel.

Hence, the proper way to implement a correlation equation approach is that when *no dilution probe is used* with the Method 21 analyzer, and the range of measurements is 0-10,000ppm, emissions would be estimated using a “default zero”, the mass emissions derived from the measurements over the screening range, and the “pegged over 10,000ppm” emission factor. Conversely, if a properly calibrated 10:1 dilution probe is used, the measurement range would be extended to 100,000ppm, and in that case the "pegged over 100,000ppm" emission factors should be used.

API recommends to ARB to adopt the approach it has taken in its GHG Compendium for estimating methane emissions from the natural gas and refinery fuel gas systems at refineries. This will include an initial estimate of such emissions, using average emission factors. Only if these emissions exceed the deMinimis threshold would refineries have to adopt a more refined approach, such as using either a Leak/No Leak or a correlation equation approach, as specified in existing guidance documents. In any case, for the “correlation equation approach” it is faulty to require the utilization of BOTH “pegged” emission factors. The actual approach is to specify the use of EITHER one of the factors, whatever is consistent with the measurements approach used at the facility.

Use of EPA TANKS Program to Estimate Methane – Section 95113(c)(3):

The EPA TANKS program is based on the methods presented in Section 7.1 of EPA's AP-42 guidance document, which in turn is based on the API Tanks Standard. The TANKS program is most appropriate for estimating standing (storage or breathing) losses and working losses from fixed rood tanks, or in the case of floating roof tanks, withdrawal and standing losses. The emission estimation in TANKS and AP-42 are based on using Raoult's Law to estimate the emissions, relating the vapor pressure of the specific compounds in the liquid mixture to the total mixture vapor pressure. Raoult's Law assumes an ideal gas in the vapor phase and an ideal solution in the liquid phase.

Such assumptions are valid for hydrocarbon compounds that are liquids at ambient temperature, and EPA TANKS can therefore be used to estimate emissions from these VOC compounds. However, CH4 is a very volatile compound, and therefore has a very strong affinity for the vapor phase. Typically, due to this high volatility, one would not expect much CH4 in crude oil when it arrives at a refinery, and the default crude oil speciation data in the EPA TANKS program does not list CH4 as one of the compounds.

Since EPA TANKS 4.09D is not capable of directly estimating CH4 emissions from crude oil tanks some back-end refinement of the EPA TANKS estimate is needed for this application. The API Compendium (Section 5.4.2, February 2004) discusses a conservative approach for estimating the CH4 emissions from petroleum storage tanks (non-flashing losses) that is designed to account for the potential of a minute amount of CH4 still being present in the crude that is processed. The method would include estimating total hydrocarbon (THC) or VOC emissions from EPA TANKS, and then multiplying the resulting emissions by an assumed CH4 concentration in the vapor.

API recognizes that such an approach would likely overestimate CH4 emissions, and may even double count emissions that have already been estimated in the other facets of industry operation. Therefore, API urges the ARB to make this requirement optional and only if facility layout or operating practice would be conducive to the presence of CH4 in the crude oil stored. Furthermore, estimating methane emissions from other refinery fractions after distillation would be a waste of resources and produce meaningless results.

Flare Emissions Equations: Section 95113(d)(2)(A)

The following revisions are suggested for the equation for flares, in line with the methodology described in the API Compendium.

The equation for CO2 accounts for the possibility that CO2 is present in the flared gas stream and would be emitted with the flare exhaust. The equation for CH4 assumes 0.5% residual, unburned CH4 remaining in the flared gas based on industry practice for well designed and operated flares, such as in refineries.

$$\begin{aligned}\text{CO}_2\text{ Emissions} = {} & \text{Volume Flared, Mscf} \times \frac{1000\text{ scf}}{\text{Mscf}} \times \text{Molar volume, } \frac{\text{lbmol}}{379.3\text{ scf}} \\ & \times \left[\sum\left(\frac{\text{mole Hydrocarbon}}{\text{mole gas}} \times \frac{A\text{ mole C}}{\text{mole Hydrocarbon}} \times \frac{FE\text{ mole CO}_2\text{ formed}}{100\text{ mole C combusted}}\right) + \frac{B\text{ mole CO}_2}{\text{mole gas}}\right] \\ & \times \frac{44\text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne CO}_2}{2204.62\text{ lb CO}_2}\end{aligned}$$

$$\begin{aligned}\text{CH}_4\text{ Emissions} = {} & \text{Volume Flared, Mscf} \times \frac{1000\text{ scf}}{\text{Mscf}} \times \text{Molar volume, } \frac{\text{lbmol}}{379.3\text{ scf}} \times \frac{C\text{ mole CH}_4}{\text{mole flared gas}} \\ & \times \frac{0.005\text{ mole residual CH}_4}{\text{mole CH}_4} \times \frac{16.04\text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne CH}_4}{2204.62\text{ lb CH}_4}\end{aligned}$$

In addition for flares, Section 95113(d)(1) requires monthly measurement by the refiner of natural gas combusted as flare pilot and purge gas. If this natural gas is provided by a fuel suppliers, the requirements under 95115(a)(2)(B and C) should apply, which allow average annual carbon content and heating value provided by the fuel supplier.