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12-6-2

Comments of the California Independent Petroleum Association on the Proposed Amendment to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

9/18/2012

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I. Introduction

The California Independent Petroleum Association[1] (CIPA) appreciates the opportunity to provide comments to the California Air Resources Board (ARB) on its consideration of proposed amendments to the Mandatory Reporting Regulation (MRR) for Greenhouse Gas Emissions. We hope our concerns can be addressed in what we believe would be reasonable changes to the MRR draft under consideration.

To begin with, we are pleased that ARB staff has ceased referring to the regulatory changes contemplated in the instant proceeding as a "harmonization" with US EPA requirements. As will be discussed in detail below, this was a charade and the changes under consideration with respect to petroleum and natural gas production are substantive departures from US EPA's Subpart W. So, while the new statement "Continue alignment of the GHG reporting requirements with the U.S. EPA, to the extent feasible, by making corrections and updates to emission estimation methods, emission factors, and reporting requirements" may be slightly less inaccurate, the contemplated changes still portend difficulty and unreasonable costs for operators subject to them.

Perhaps the single largest change in the amendments in terms of impact on regulated entities is the perversion of the definition of facility. Oil and gas producers operate in many different jurisdictions and as a result have seen some slight variation with respect to the definition of what exactly constitutes a facility, but the abomination contained in the amendments under consideration defies logic and flies in the face of reasonable regulatory construction. This definition also is a complete departure from the EPA's Subpart W definition and we believe that ARB has not clearly demonstrated a reasonable and defensible argument for this departure.

Further under the banner of general comments, CIPA takes exception to the characterization of these amendments as insignificant, slight modifications. Having just gone through the rigorous reporting and verification exercise, CIPA members can attest to the fact that the current reporting regime is rigorous and costly and the rigor and expense will be compounded by the contemplated changes under consideration.

Moreover, the cumulative emissions totals divided by the expense of their very determination fails any reasonable cost benefit analysis. If the ISOR was intellectually honest, the cost implications of the amendments would be recognized as significant and the desired amendments re-assessed and ultimately stricken from consideration.

Finally, we offer a number of suggested changes that are needed to make the theoretical applicable to the real world. There are numerous problems with the details of the regulation that need to be addressed so compliance can actually be achieved.

[1] The mission of the California Independent Petroleum Association (CIPA) is to promote greater understanding and awareness of the unique nature of California's independent oil and natural gas producers and the market place in which they operate; highlight the economic contributions made by California independents to local, state and national economies; foster the efficient utilization of California's petroleum resources; promote a balanced approach to resource development and environmental protection and improve business conditions for members of our industry. CIPA represents over 470 independent oil and gas producers, royalty owners, and service and supply companies with operations in California.

II. General Comments

Definition of "facility"

The MRR's definition of an onshore petroleum and natural gas production facility at 95102(a)(273) is identical to the definition that was in the November 30, 2010, version of Subpart W. We understand and are applying ARB's interpretation of this definition (as clarified in the February 29, 2012 guidance document) to our industry. As a result, confusion now clouds our industry's use of the simple term "facility" without specifying the context (e.g., local air regulations, Subpart C, Subpart W, ARB MRR). In addition, we continue to object to ARB's incognizable characterization of the evolution of their interpretation of the definition and its departure from EPA's interpretation of the same definition as it has created a significant additional reporting burden for what amounts to a very small amount of emissions.

ARB has repeatedly stated that their interpretation is consistent with EPA's interpretation of the definition in the November 30, 2010, version of Subpart W and only deviated from EPA's interpretation when EPA "changed" the definition with the December 23, 2011, revisions to Subpart W. However, EPA characterized the December 23, 2011, revision to the definition as a "clarification", not a "change". Further, EPA's use of the attached slide number 34 from EPA's January 5, 2011, Subpart W training webinar clearly indicates EPA's interpretation is that central processing facilities are not part of a basin-wide Subpart W facility[2]. Thus, ARB has chosen to interpret the November 30, 2010, Subpart W definition differently from the way EPA interprets it.

ARB has clearly stated their intent to continue interpreting the definition in the broadest terms (i.e., including equipment at central processing facilities as part of basin-wide Subpart W facilities), but we believe ARB should explicitly acknowledge (e.g., in the FSOR) the fact that they have chosen to interpret EPA's November 30, 2010, definition differently from EPA, not that EPA chose to "change" the definition when it issued its December 23, 2011, revisions to Subpart W.

The significance of ARB's broad interpretation of the definition of an onshore petroleum and natural gas production facility is that facilities are required to gather data and report emissions for Subpart W type emission sources to ARB when they (in most cases) are not required to report those emissions to EPA. This poses a significant additional burden for reporters even though the emissions associated with these sources are small relative to emissions from combustion. This significant difference only creates confusion within the regulated community in both implementation and reporting for two (2) separate regulations that are attempting to achieve the same goal. May we remind you that this very confusion to both ARB and the regulated community resulted in the extension of the reporting deadline for this year and the continuous adjustments/clarifications that ARB continues to make during the evolution of this regulation?

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[2] See Attachment

Significance of the proposed MRR revisions
ARB characterizes the proposed amendments to the MRR as relatively insignificant. For example:

- "The proposed amendments represent minor but necessary revisions to the current reporting regulation." (page iii of the Executive Summary of the ISOR)
- ".... slightly modify some of reporting requirements...." and "ARB has strived to minimize changes from the U.S. EPA Subpart W" (page 14 of the ISOR)

In the case of the onshore petroleum and natural gas production industry, we believe the proposed amendments are NOT "minor" and that ARB's changes from the U.S. EPA Subpart W requirements are significant. ARB has modified the emissions calculation methodologies for seven of the twenty emissions source categories listed in Subpart W, specifically,

- Pneumatic device venting;
- Pneumatic pump venting;
- Oil storage tanks;
- Reciprocating compressors;
- Dehydrator vents;
- Centrifugal compressors; and
- Equipment leaks.

The emissions calculation methodologies for these seven source categories were modified in ways that either expand the applicability of the requirements or limit the calculation options and flexibility available in Subpart W.

In addition, the MRR requires reporting of emissions for two source categories not even addressed by Subpart W for onshore petroleum and natural gas production facilities:

- Equipment and pipeline blowdowns; and
- Produced water storage.

ARB's stated reason for increasing the stringency of and adding to the reporting requirements in Subpart W is ".... because the EPA methods were not rigorous enough to support the needs of the cap-and-trade program and the statewide greenhouse gas inventory program" (page 10 of the ISOR). But many of the above categories of emissions are either wholly or partially excluded from "covered emissions" under cap-and-trade. And using the "statewide greenhouse gas inventory program" as justification for increased stringency is weak without offering some discussion of why this is the case, e.g., how accurate do the emissions estimates from these categories need to be given they are relatively small (by more than an order of magnitude) compared to combustion emissions in order to satisfy the needs of the "statewide greenhouse gas inventory program".

Cost effectiveness of the proposed MRR revisions

In the ISOR's discussion of the cost and economic impacts of the MRR revisions, ARB acknowledges that one of the proposed rule amendments that may lead to a noticeable change in costs is "additional monitoring and reporting requirements for oil and gas production entities." This is but a truism and we certainly agree with this statement. In particular, the additional costs associated with gathering data and calculating, reporting, and verifying emissions for Subpart W emission source categories in accordance with the MRR's stringent requirements is out of balance with the amount of emissions associated with these sources.

Facilities that reported emissions for calendar year 2011 generally found that the additional effort associated with calculating and reporting emissions for these sources exceeded 50% of the total effort for the 2011 data reports, yet accounted for relatively small amounts of emissions (i.e., less than 3% of total facility emissions, which were generally reported as de minimus). When it came to verification of the 2011 data reports, the effort was even more out of balance, i.e., most of the questions raised by verifiers and most of the reporters' efforts to respond to questions during verification were associated with Subpart W sources. Increasing the stringency of requirements for these sources will only increase the imbalance that already exists between effort (*cost*) and reported emissions.

We are also concerned that these cost impacts tend to be disproportionately distributed to smaller entities. This is because smaller entities tend to operate facilities that are less concentrated and centralized, increasing the effort to gather data and calculate and report emissions (e.g., more oil and water samples needed to calculate emissions from more oil and water storage facilities). We note that Table VI-2 of the ISOR indicates that 21 of the 26 oil and gas production facilities affected by the MRR are "small" or "medium" facilities.

Finally, for comments related to additional cost impacts that ARB may not have accounted for in its analysis of cost and economic impacts of the proposed amendments to the MRR, see our specific comments below regarding:

- 95115(h) – Aggregation of Units; and
- 95156 – Additional Data Reporting Requirements.

III. Specific Comments

Sections 95150 through 95158

1. 95101(h)(1) – Cessation of Reporting

   Indicates that records must be retained for "... each of the five consecutive years and retain such records for five years...". We believe this should say records must be retained for "... each of the <u>three</u> consecutive years and retain such records for five years... ".

2. 95102(a)(273) – Onshore Petroleum and Natural Gas Production Facility

   We strongly recommend that a definition be added for the phrase "associated with a well pad" as EPA has done in Subpart W for the phrase "associated with a single well pad". In its definition of an onshore petroleum and natural gas production (O&G) facility, ARB uses the phrase "associated with a well pad" and EPA (in its 12-23-2011 version of Subpart W) uses the phrase "associated with a single well pad". Although the two phrases are nearly identical (and, thus, most readers would interpret them to mean the same thing), ARB interprets "associated with a well pad" much differently than EPA interprets "associated with a single well pad". EPA's regulation explicitly defines the phrase "associated with a single well pad", but ARB's regulation does not define the phrase "associated with a well pad". This opens the door to potential confusion and incorrect interpretation of ARB's intent. As we have stated as part of separate communications and in our general comments above, official EPA records available to the public articulate a different evolution of this issue than that described by ARB staff.

3. 95102(a)(416) – Definition of "Sales Oil"

   As written, the proposed definition of "sales oil" does not clearly include oil that is trucked to a third party receiving facility where custody transfer occurs. We suggest changing the phrase "custody transfer tank gauge" to "other point of custody transfer".

4. 95115(c)(4) – Choice of Tier for Calculating CO2 emissions

   The second sentence says: "The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR 98.33". But, in explaining Equation C-2b of 40 CFR 98.33, 98.33(a)(2)(ii) states that a <u>weighted</u> average value is to be calculated only when monthly or more frequent samples are received and an <u>arithmetic</u> average is to be calculated when samples are received less frequently than monthly. The MRR should simply reference 98.33(a)(2)(ii) without specifying whether the annual average is a weighted or arithmetic average (allowing the language in 98.33(a)(2)(ii) to govern).

5. 95115(h) – Aggregation of Units

   ARB staff have indicated that the proposed limit to aggregation of units is not intended to require operators to install additional fuel metering equipment (to measure fuel separately for process heaters, boilers, turbines, RICEs, and flare pilots) or to subject "downstream meters" to the accuracy and calibration requirements in 95103(k), but only to require operators to utilize "engineering estimates" to allocate fuel use to, and report emissions for, individual unit types. Language should be added to the regulation to make this clear. Even so, this change would impose significant additional burden on operators and verifiers to compile the additional data, set up the additional configurations in the reporting tool, enter the additional data, and explain the reported data to a verifier. And, even though total reported emissions for the facility would be unchanged, the number of pages in a facility report could double or triple, adding further to the time to compile and verify the report. We doubt the costs associated with these additional tasks were accounted for in ARB's analysis of economic impacts. We encourage ARB staff to find less burdensome ways to obtain the additional desired data. We suggest allowing facilities to provide facility level estimates of fuel and emissions data by unit type. Such estimates would be sufficient to understand fuel use and emissions by unit type without placing significant additional burden on reporters and verifiers.

Sections 95150 through 95158

6. 95153(d) – Dehydrator vents.

   If a dehydrator vent is hard-piped to a closed system (e.g., a vapor recovery system, fuel gas system, or gas re-injection system) that is incapable of venting to atmosphere (i.e., 100% control), literal application of the regulation requires that emissions be calculated per (d)(1) even though the emissions would be adjusted to zero per (d)(2). The regulation should be modified to not require calculation of emissions per (d)(1) in such cases.

7. 95153(l) – Flare stack or other destruction device emissions.

   Paragraph (l)(3)(B) is applicable to a "hydrocarbon product stream" at "any applicable industry segment". Thus, we conclude this paragraph is applicable to flare streams at onshore oil and gas production facilities. If this is not the case, clarification is needed in the regulation.

   Paragraph (l)(8) specifies that Equation 37 in paragraph (y) be used to calculate N2O emissions. But Equation 37 prescribes the use of an HHV value of 1235 btu/scf. This is not reasonable for many oilfield gas streams, especially "low Btu gas" streams that account for most of the gas flared at thermal production facilities. Language should be added to the regulation to allow the use of actual HHV data if it is available.

8. 95153(m) and (n) – Centrifugal and Reciprocating compressor venting.

   The regulation should provide an exemption from the annual measurements for compressor vents that are hard-piped to closed systems (e.g., vapor recovery, fuel gas, or gas-re-injection systems).
   Consistent with the definition in 95102(a)(476), such systems consist of piping and connections that provide 100% containment without "operating" a piece of equipment for which a log would need to be maintained as described in paragraph (l)(6).

   Paragraph (m)(1) includes the phrase "… the operator must conduct an annual measurement in each operating mode in which it is found for more than 200 hours in a calendar year". The lack of clarity in this phrase was discussed with ARB staff in a conference call on July 3, 2012. ARB staff indicated that the phrase was intended to mean that an annual measurement is to be made in each mode in which the compressor <u>operates</u> for more than 200 hours in a calendar year. If this is ARB's intent, the regulatory language should be changed to add clarity.

   The requirement for quarterly gas samples in sub-paragraph (m)(4) is not reasonable. Annual sampling (or even engineering judgment based on process knowledge) should be sufficient given that the compressor measurements themselves are only required annually.

   ARB is unnecessarily expanding on Subpart W requirements here in two ways. First, Subpart W does not require any of the specified measurements at all for onshore oil and gas facilities. Second, where measurements are required for other types of facilities, Subpart W simply requires a single annual measurement in the operating mode in which the compressor is found at the time of the annual measurement. This expansion of Subpart W requirements does not seem justified given the relatively small amount of emissions associated with this source category.

9. 95153(o) and (p) – Leak detection and leaker emission factors and Population count and population emission factors.

The reference in paragraph (o) has been corrected from the June Discussion Draft so it is now clear that (o) is applicable to O&G facilities. However, paragraph (p) still contains language for O&G facilities even though it is no longer applicable to such facilities.

The regulation needs to specify "leaker emission factors" for onshore O&G facilities (the factors in Table 1A are "Population Emission Factors", not "Leaker Emission Factors").

As discussed in previous conversations, we recommend providing an option in the regulation that would allow operators to use emissions calculation methodologies developed by EPA and CAPCOA in combination with equipment leak data already being gathered to comply with existing local fugitive I&M regulations (e.g., SCAQMD Rule 1173) to calculate and report GHG emissions to ARB.

10. 95153(s) – GHG volumetric emissions.

Sub-paragraph (2)(A) specifies, for an O&G facility, how to determine the value for GHG mole fraction to be used in Equation 31. The first sentence defines it as the "GHG mole fraction in produced pipeline quality natural gas" and the last sentence says that "the composition of non-pipeline quality natural gas must be determined as specified in section 95115(c)(4)". These two sentences seem to be in conflict. We assume the last sentence is the correct one (recognizing the comments above related to 95115(c)(4) and that calculation of a <u>weighted</u> annual average may not be practical in all cases, e.g, fugitive emissions from equipment leaks). If this is not the case, clarification should be provided in the regulation.

11. 95153(v) – Crude oil and condensate dissolved CO2 and CH4.

Where the definition of S_{cc} refers to "produced water", it should refer to "crude oil or condensate".

12. 95153(y) – Onshore petroleum and natural gas production and natural gas distribution combustion emissions.

Paragraph (y)(1) states the emission factor for natural gas in Table C-1 of Subpart C may be used "if the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 970 Btu per standard cubic foot". The minimum high heat value specification is only part of the criteria for pipeline quality natural gas. To avoid confusion, the sentence should simply say "if the fuel combusted in natural gas and is of pipeline quality specification as defined in 95102(a)".

Also, as stated above, Equation 37 prescribes the use of an HHV value of 1235. This is not reasonable for many oilfield gas streams, especially "low Btu gas" that is commonly used as fuel in certain oilfield combustion equipment (e.g., steam generators at thermal production facilities). Language should be added to the regulation to allow the use of actual HHV data if it is available.

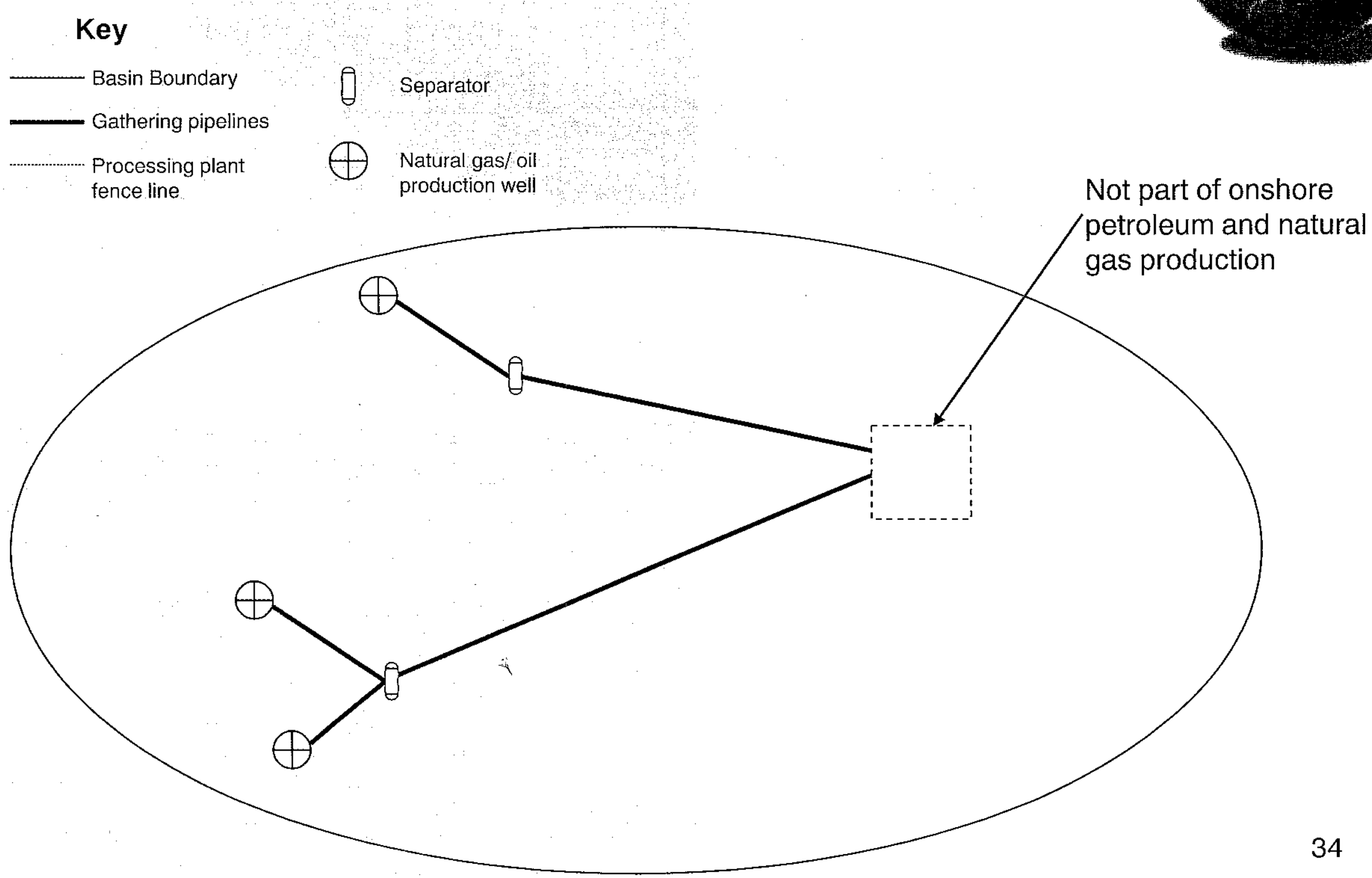
13. 95156 – Additional Data Reporting Requirements

Paragraph (a)(11) says: "The operator of an onshore petroleum and natural gas production facility may voluntarily report the annual product data information in sections 95156(a)(9)-(10) [i.e., MMBtu of associated gas] for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article." We interpret this to mean that operators will only receive free allocations of GHG allowances for their 2011 and 2012 associated gas production if the associated gas product data is successfully verified by a third party verifier and that operators who reported associated gas product data as part of their 2011 emissions data report cannot yet count on receiving free allocations of GHG allowances for their 2011 associated gas production even though their 2011 emissions data reports have already been verified. In effect, this imposes a new verification requirement retroactively on operators that voluntarily report their 2011 and 2012 gas production. If this is not a correct interpretation of the regulation, the regulatory language should be clarified.

Paragraph (a)(11) goes on to say the annual product data must be reported for 2013 (and future years?). Some operators will be forced to install additional metering prior to January 1, 2013, (and comply with applicable accuracy and calibration requirements) in order to comply with this requirement. Installation of the additional metering by January 1, 2013, may not be feasible. Because reporting of the gas product data is (a) primarily for the benefit of operators (i.e., to receive more free allocations), (b) may not translate to enough free allowance allocations to justify the cost of additional metering, (c) does not affect reported emissions, and (d) was likely not included in ARB's analysis of the cost impacts of the regulatory amendments, we suggest the additional product data reporting continue to be optional in 2013 (and future years).

14. 95157(d) – Specifically what "annual throughput" is to be reported?

Example Facilities



Comments of the California Independent Petroleum Association on "Attachment B" Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

9/18/2012

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The California Independent Petroleum Association[1] (CIPA) appreciates the opportunity to provide comments to the California Air Resources Board (ARB) on its consideration of "Attachment B" proposed amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms.

We understand that the changes to the Cap and Trade program are precipitated by amendments to the Mandatory Reporting Regulation (MRR) and we submit these comments both within this context and with respect to the program itself.

First, with respect to the Cap and Trade Program generally, we have consistently held the position that a market based system is the most efficient method to reduce emissions. We wrote in December 2010:

> Consistent with our previous comments, we believe that market mechanisms such as cap-and-trade are far preferable to draconian command and control regulations and can be deployed to reduce the costs of achieving greenhouse gas emissions reductions under AB 32. Flexible options for compliance are fundamental for companies that have already undertaken considerable reductions through efficiency measures and/or best available control technologies, have limited ability to make onsite reductions or desire to expand their operations in California.

However, the Legislative Analyst's Office as the rule was being developed covered quite comprehensively that enough activity had been undertaken- numerous programs and policies put into place that coupled with dramatically reduced economic output have allowed us to achieve, or at least establish the glide path to the emission reduction targets envisioned by the framers of AB 32. This caused us to question the need for the Cap and Trade Program altogether.

Insofar as we look at the market design features of the program and inherently understand that no matter how well intentioned they are complicated and complex beyond reason and portend disaster for the program itself, the economy as a whole and regulated entities specifically, we wonder why does this policy continue?

Nevertheless, notwithstanding an overly complex design and a lack of participation by any other jurisdictions in the United States this largely unnecessary program continues. We understand that ARB is irreversibly committed to this policy. But we lament that compliance costs will be severe given this complexity- both to acquire allowances and to keep track of all program requirements- and leakage will be extensive as regulated entities that can will uproot and take flight to escape these only-in-California costs.

[1] The mission of the California Independent Petroleum Association (CIPA) is to promote greater understanding and awareness of the unique nature of California's independent oil and natural gas producers and the market place in which they operate; highlight the economic contributions made by California independents to local, state and national economies; foster the efficient utilization of California's petroleum resources; promote a balanced approach to resource development and environmental protection and improve business conditions for members of our industry. CIPA represents over 470 independent oil and gas producers, royalty owners, and service and supply companies with operations in California.

Inasmuch as the adoption of the "ten percent haircut" will represent immediate costs for regulated entities estimated by the Legislative Analyst's Office (LAO) to be up to $3 BILLION in the first year alone, it is hard to understand how ARB can be so dismissive of the looming impact to the state economy.

We believe, understanding that the program will go forward, that impact on regulated parties and the economy as a whole could be mitigated extensively by adopting a 100 percent allocation. In fact, in a letter responding to legislative inquiries regarding the necessity of auctioning allowances, the LAO wrote:

> "… it is the declining cap on emissions that will reduce the state's overall level of GHGs-not the manner in which allowances are introduced into the market. Thus, an allowance auction is not necessary to meet the AB 32 goal of reducing GHG emissions statewide to 1990 levels by 2020." [2]

Further, in the same letter, the LAO drew a direct correlation between free allowances and reduced cost and reduced leakage. The LAO recognized that the Cap and Trade regulation will increase the marginal cost of production for covered entities and those costs will be passed along to consumers. Consumers will then seek lower cost goods not produced in California. They concluded that the way around this economic doom spiral was by ***allocating 100 percent free allowances***. This makes so much sense to us we wondered why it was an issue until we saw the fight over the money that would be generated.

ARB should allocate 100 percent of covered entities' allowances.

<u>Facility Definition</u>

Then there is the definition of the term "facility":

> (C) "Facility," with respect to onshore petroleum and natural gas production for the purposes of sections 95150 through 95158 of MRR, means all petroleum and natural gas equipment on a well-pad or associated with a well pad ***and CO2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in section 95102(a) of MRR. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.***(emphasis added)

We will restate our comments on the same change to the MRR: perhaps the single largest change in the amendments in terms of impact on regulated entities in the petroleum and natural gas production sector is the perversion of the definition of facility. Oil and gas

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[2] Letter to Assembly Member Henry Perea, Dated August 17, 2012

producers operate in many different jurisdictions and as a result have seen some slight variation with respect to the definition of what exactly constitutes a facility, but the abomination contained in the amendments under consideration defies logic and flies in the face of reasonable regulatory construction. This definition also is a complete departure from the EPA's Subpart W definition and we believe that ARB has not clearly demonstrated a reasonable or defensible argument for this departure.

As a result of these definitional changes, confusion now clouds our industry's use of the simple term "facility" without specifying the context (e.g., local air regulations, Subpart C, Subpart W, MRR, Cap and Trade). In addition, we continue to object to ARB's characterization of the evolution of their interpretation of the definition and its departure from EPA's interpretation of the same definition as it has created a significant additional reporting burden for what amounts to a very small amount of emissions.

ARB has repeatedly stated that their interpretation is consistent with EPA's interpretation of the definition in the November 30, 2010, version of Subpart W and only deviated from EPA's interpretation when EPA "changed" the definition with the December 23, 2011, revisions to Subpart W. However, EPA characterized the December 23, 2011, revision to the definition as a "clarification", not a "change". Further, EPA's use of the attached slide number 34 from EPA's January 5, 2011, Subpart W training webinar clearly indicates EPA's interpretation is that central processing facilities are not part of a basin-wide Subpart W facility[3]. Thus, ARB has chosen to interpret the November 30, 2010, Subpart W definition differently from the way EPA interprets it.

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The significance of ARB's broad interpretation of the definition of an onshore petroleum and natural gas production facility is that facilities are required to gather data and report emissions for Subpart W type emission sources to ARB when they (in most cases) are not required to report those emissions to EPA. This poses a significant additional burden for reporters even though the emissions associated with these sources are small relative to emissions from combustion.

We appeal to you to revisit the definition of facility for oil and gas production facilities and hope you would recognize the difficulties posed by the proposed unworkable definition and find your way to changing it in a way that makes sense for all parties concerned.

[3] See Attachment

Example Facilities