Comments on 5-31-2016 version of proposed:

“GHG Emission Standards for Crude Oil and Natural Gas Facilities”

(CCR, Title 17, Div. 3, Ch. 1, Subchapter 10 - Climate Change, Article 4, Subarticle 13)

General comments regarding throughput and flash emission calculations

Clarification is needed regarding the throughput value to be used for calculating annual separator / tank system emissions in 95668(a)(5)(C) and 95673(b)(2)(A)(3)(c), for determining eligibility for the exemption in 95668(a)(2)(A), and for calculating the percent increase in annual throughput in 95668(a)(8)(A). I suggest the value should represent average daily throughput for the previous full calendar year, i.e., total calendar year throughput in barrels divided by number of days in the year. This is consistent with an annual emissions threshold (10 MT CH4 per year) and the manner in which emissions estimates and reductions are calculated in Appendix D of the Staff Report. Throughputs, lacking significant development activity, generally decrease with time for any given separator / tank system. So, use of the average daily throughput for the previous calendar year will generally yield a conservative (i.e., high) estimate of current annual throughput and emissions and will bring consistency to how various operators interpret the rule and quantify and report their flash emission calculations to ARB.

Also, I suggest that throughput data should be based on sales data when available and, when sales data is not available (e.g., for produced water or for an individual separator / tank system not uniquely associated with sales data), should be <u>consistent with</u> sales data and with crude oil and produced water production data reported to DOGGR.

95666 – Applicability

95666 uses the term “sectors” in the same manner the MRR and EPA’s Subpart W use the term “segments”. Using a different term to apparently mean the same thing, especially when neither term is defined, creates unnecessary uncertainty and confusion when interpreting the details of the regulation. I suggest replacing the word “sectors” with “segments” to achieve consistency with the MRR and with EPA’s Subpart W. (NOTE: The remainder of these comments will use “sector / segment” where I suggest the use of simply “segment”.)

I also suggest revising the sector / segment list in 95666(a) to (1) list offshore production as a separate sector / segment and (2) include the word “onshore” in the description of each of the remaining sectors / segments. Further, I suggest the “onshore crude oil or natural gas production” sector / segment be revised to “onshore crude oil or natural gas production equipment located on well pads”. These changes would provide a clearer distinction regarding what constitutes crude oil “production” equipment (sector / segment 1) and crude oil and produced water “separation and storage” equipment (sector / segment 2) and would achieve greater consistency with the MRR and with EPA’s Subpart W, thus reducing uncertainty and confusion in interpreting the regulation.

Finally, there are numerous references throughout the proposed regulation to “facilities listed in section 95666”. However, the list in 95666 is a list of sectors / segments, not a list of facilities. Facilities are only generally described in 95666 as “facilities in the sectors listed below……”. The term “facility” is then more specifically defined in section 95667. I suggest replacing all occurrences of the phrase "facilities listed in section 95666" with the phrase "facilities in the sectors / segments listed in 95666".

95667 – Definitions

(11) – "Component".

The proposed definition is different from the definition of "component" in the MRR and in EPA's Subpart W. Is there a specific reason for this? Unless the definition is intentionally different to serve a specific purpose, it creates unnecessary uncertainty and confusion when interpreting the regulation.

(18) – "Facility"

For onshore production facilities in particular, the definition of "facility" in this proposed regulation is not consistent with the definitions in either Subpart W or the MRR. This may cause uncertainty, confusion, and inconsistency in interpreting the regulation, in defining record keeping and reporting practices, and in agency and public use of the data collected under these regulations. Subpart W defines an "onshore production facility" as all equipment located on and "associated with" (specifically defined in the regulation) single well pads in a geologic basin and defines a "gathering and boosting facility" as all gathering and boosting systems / stations in a geologic basin. The MRR (in a guidance document) more broadly defines an "onshore production facility" to include all equipment in a geologic basin, including equipment on well pads and "associated with" (undefined in the regulation, but discussed in a guidance document) those well pads (not just with single well pads), including centralized separation and storage facilities, small gas processing plants, and centralized steam or electricity generation equipment serving those well pads, separation and storage facilities, and gas processing plants.

An onshore oil and gas production facility already must conform to at least three different definitions of "facility", depending on the air regulation at issue: (1) the traditional contiguous and adjacent property definition used by local air districts and in EPA's NSR, NSPS and Title V regulations, (2) the basin-wide definition for the onshore production and the onshore gathering and boosting segments in EPA's Subpart W regulation, and (3) the all-encompassing basin-wide definition (which is different from Subpart W and is the broadest of all) in the MRR. The definition in the proposed regulation is the traditional "contiguous and adjacent property" definition. However, as evidenced by the need for EPA's recently issued "Source Determination for Certain Emission Units in the Oil and Natural Gas Sector" for use in the NSR, NSPS, and Title V programs, even that definition (specifically the term "adjacent") has been interpreted differently by different agencies and even by the same agency in different geographic areas. This unnecessarily complex web of regulations with different definitions of "facility" for the same industry sector / segment causes inefficient and unclear communications within the regulated industry, between the industry and its regulators, and in communication with the public. Again, this creates uncertainty, confusion, and inconsistency in interpreting the regulation, in defining record keeping and reporting practices, and in agency and public use of the data collected under these regulations.

My preference is for ARB to use the same definition of "facility" in this regulation as in the MRR. This would at least provide consistency between ARB's various GHG regulations. However, if it is decided to retain the currently proposed definition of "facility", I suggest that operators be allowed to define boundaries and submit reports for their facilities in accordance with the manner that local air districts have interpreted the term "adjacent" to define these "facilities". This means that some facilities will be defined very broadly (though not basin-wide as in the MRR) and may include equipment that belongs to more than one sector / segment listed in 95666(a) and which may be located at several different physical addresses. For example, a facility that includes (1) onshore oil production (equipment located on well pads), (2) onshore crude oil and produced water separation and storage, and (3) an onshore natural gas processing plant may be one "facility" under the proposed definition. If each well pad, each separation and storage site, and each gas processing facility is considered a separate "facility", the number of "facilities" will be significantly increased and the record keeping and reporting required by the regulation will be unnecessarily complex and burdensome.

(30) – "Natural gas gathering and boosting station"

The phrase "associated with" in the proposed definition is not defined and, thus, the definition lacks clarity. For example, if a reciprocating compressor is located at either an "onshore crude oil production" site (i.e., a crude oil well pad) or at a "crude oil, condensate, and produced water separation and storage facility" and is used to "move" associated gas collected from well casings and/or from a tank vapor recovery system to a sales point or a gas processing plant via pipeline, is the compressor considered a, or part of a, "natural gas gathering and boosting station"? Based on the diagrams in Figures 6, 7, and 8 of the Staff Report, Table 4 of the Staff Report, and the Staff Report's discussion of those items, I believe the answer is "no". If ARB agrees, I suggest adding the following sentence to the definition of "Natural gas gathering and boosting station":

> "This does not include equipment and components located at crude oil production sites (well pads) or at crude oil and produced water separation and storage sites used to move associated gas to a processing plant or sales pipeline." (It may also be appropriate for the regulation to include a definition of "associated gas", e.g., the definition in the MRR.)

(47) – "Pressure vessel"

There is a typo in the first sentence, i.e., "means any a hollow container…..".

Also, for clarity and for consistency with the definition of "tank", I suggest revising the latter portion of the definition to read: "….. and designed to operate at 15 psig normal operating pressure or above without vapor loss to the atmosphere."

(53) - "Separator"

I suggest revising the second sentence to say: "In crude oil production a separator may be referred to as a wash tank, a free water knockout (FWKO), a heater treater, or any other tank or pressure vessel used for the separation of crude oil from water."

(60) – "Vapor control device"

I suggest adding the following phrase to the end of the proposed definition: "…… without serving any other useful process purpose". As is, the proposed definition would appear to include combustion devices that destroy collected vapors while also performing a useful process purpose such as heating of process fluids or generating electricity. I don't believe this is the intent.

(61) - "Vapor Control Efficiency"

Unless referring only to capture efficiency, vapor control efficiency is generally expressed as percent by weight, computed by dividing outlet mass emissions by inlet mass emissions. And it is generally expressed as a percent by weight of a specific compound or group of compounds. The proposed definition specifies "total hydrocarbon concentration at the inlet and outlet of the vapor control device". Measuring only total hydrocarbon concentrations in inlet and outlet streams will generally not yield a true indication of vapor control efficiency on either a mass or volume basis.

Also, I suggest that all instances of the phrase "95% vapor control efficiency of total hydrocarbon emissions" in the regulation be revised to "95% control of total hydrocarbon emissions by volume" or "95% control of total hydrocarbon emissions by weight", whichever is appropriate. Alternatively, since this is a regulation to control methane emissions, it may be more appropriate to replace the phrase "95% vapor control efficiency of total hydrocarbon emissions" with the phrase "95% control of methane emissions" (in which case it's not necessary to specify whether the percent is by volume or by mass).

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95668 – Standards

(a) - Separator and Tank Systems

(a)(2)(A) – Clarification is needed regarding the throughput level thresholds of 50 BOPD and 200 BWPD. As discussed above in "General comments regarding throughput and flash emission calculations", I suggest the thresholds be defined as average daily throughputs for an entire calendar year. I also suggest specifying that the first flash analysis testing must be performed by January 1, 2018, or during the calendar year following the calendar year in which the average daily throughput first exceeds either of the thresholds.

(a)(2)(C) – I suggest revising this to read: "Separator and tank systems that do not contain crude oil, condensate, or produced water at the time field sampling is scheduled to occur. If a separator and tank system that is not sampled for this reason is later returned to operation, sampling and flash analysis shall occur within 90 days of initial production into the system."

(a)(2)(D) – I suggest revising this to read: "….. from any newly completed (i.e., drilled and cased) well for up to 90 calendar days…..". Once a well has been drilled and cased, completion and testing of the well is sometimes deferred for a period of time for logistical, economical, or other reasons. The need for flash analysis testing should not dictate when a newly drilled well must be completed to establish initial production.

(a)(4) – Instead of "Beginning January 1, 2018, owners or operators of new separator and tank systems that are not controlled……", I suggest: "Owners or operators of separator and tank systems which first receive production on or after January 1, 2018, that are not controlled….."

(a)(6) and (a)(7) – A new or modified vapor collection system requires an air permit, construction of the system cannot commence until a permit is issued, and it is not possible to obtain a variance from the requirement to obtain a permit. In consideration of this, I suggest the compliance date should be the date by which an operator must submit a permit <u>application</u> to the local district or other permitting authority. Once an operator determines (based on flash analysis) that an uncontrolled system requires vapor control, several months will generally be required to design, permit, and install such a system. In some Districts, it can take a year or more for the District to process a permit application and issue a permit. If CEQA review is triggered (which has become a more common occurrence), it often takes even longer. In absence of a permit, an operator would need to curtail production to a level that results in emissions less than 10 MT CH_4 per year from the subject separator / tank system in order to avoid operating out of compliance (see suggestion below regarding an operator option to limit throughput). This curtailed level of production may not be economical and, thus, could significantly impair the operator's return on investment or even require the operator to completely shut in the separator / tank system and its associated oil and gas production. I suggest an operator only be required to submit an <u>application</u> for a permit within 90 days of the date of the flash analysis that indicates a need for a vapor recovery system and that a reasonable time frame of, say, 180 days, be allowed to procure, install, and commission equipment once a permit is issued (with provisions for extension if permit issuance is delayed by the permitting authority). This would relieve the operator from potential liability of operating out of compliance because of delays caused by the permitting agency's timeline to process and issue a permit which are beyond the operator's reasonable control.

Finally, if the above recommendation to use the average daily throughput for the previous calendar year as the basis for flash emission calculations is accepted, an operator should have the opportunity to limit throughput for a separator / tank system to ensure annual emissions are less than the 10 MT CH4 per year threshold. I suggest the same timeline as above would apply, i.e., within 90 days of the date of the flash analysis that exceeded 10 MT CH4 per year, the operator must submit an application to modify the permit to limit the throughput. [If the throughput limit is greater than either 50 BOPD or 200 BWPD, the affected separator / tank system would continue to be subject to 95668(a)(8), requiring continued flash analysis testing as applicable).]

(a)(8)(A) – See general comments above regarding throughput and flash emission calculations.

(b) - Circulation Tanks Used for Well Stimulation Treatments

(b)(1) – Regarding the requirement for a "best management practices plan to limit methane emissions from circulation tanks", the rule specifies that owners or operators "shall provide that plan to ARB" (by January 1, 2018), but does not specify that ARB may approve or disapprove the plan. However, the Staff Report, on page 39, says "Additionally, ARB's Executive Officer may approve or disapprove the plan, in whole or in part." I assume the Staff Report is incorrect and that ARB approval of a plan will <u>not</u> be required for an owner or operator to proceed with a well stimulation treatment that involves the use of a circulation tank. If ARB intends for plan approval to be required, it should be specified in the rule. And then, to avoid the potential for unnecessary and costly delays in performing needed well stimulation treatments, owners / operators will need to know with certainty the timeframe required for ARB's review and approval or disapproval of both an originally submitted plan as well as any amended plan that may be needed to secure ARB approval.

Also, many smaller operators rarely perform "well stimulation treatments" as defined in the rule, especially now during a time of relatively low crude oil prices. But these operators will need to either develop and submit a "just in case" plan by January 1, 2018, or accept the risk that they won't be able to perform a "well stimulation treatment" if the need arises after that date. If they choose to develop and submit a "just in case" plan, there's a good chance their time and effort will be wasted. To address this concern, I suggest including a maximum number of well stimulation treatments that could be performed by any one operator in any one calendar year that would not trigger the requirement for a best practices management plan. I suggest this threshold be five "well stimulation treatments" (as defined in the regulation) in any one calendar year.

(b)(2) – Regarding the requirement to submit a written report of circulation tank usage and emission control effectiveness by January 1, 2019, I suggest the deadline be revised to June 1, 2019. This will enable operators to include the results of all calendar year 2018 activity in their reports, which will result in a more robust set of data for analysis.

(b)(3) - To require vapor control with 95% efficiency on all circulation tanks by January 1, 2020, suggests that ARB has already concluded that such control is technically and economically feasible. If this is the case, there is no reason to delay this requirement to 2020 or to require operators to prepare and submit a best management practices plan or to prepare and submit written reports of their experience with various control techniques. I suggest this requirement be deleted from the current regulation and then reconsidered once the written reports required by (b)(2) have been submitted and evaluated. Then, the regulation can be amended as warranted <u>based on actual data</u>.

(c) - Vapor Collection Systems and Vapor Control Devices

(c)(2) – I suggest that collected vapors be allowed to be directed to either existing, new, or modified sales gas, fuel gas, or gas disposal systems as long as compliance with all applicable federal, state, and local requirements is achieved.

(c)(3) – Consistent with the suggested change to (c)(2) above, I suggest that any collected vapors not able to be directed to an existing, new, or modified sales gas, fuel gas, or gas disposal system be directed to a vapor control device - either existing, new, or modified - that meets the requirements of (c)(4).

c)(6) – It should be clarified that vapor control system downtime does not count toward the 30 calendar days allowed if the equipment served by the vapor control system is not operating (i.e., has zero throughput).

(d) – Reciprocating Natural Gas Compressors

(d)(2)(A) – It appears the word "powered" is a typo and should be deleted.

(d)(3) – I suggest adding "crude oil, condensate, and produced water separation and storage facilities" [corresponding to 95666(a)(2)] to the types of facilities subject to these requirements. Based on explanatory material in the Staff Report (especially Table 4: Control Mechanisms by Category) and the lack of inclusion of "crude oil, condensate, and produced water separation and storage facilities" in (d)(4), I believe this is consistent with ARB's intent.

(d)(4) – I suggest that reciprocating compressors with a maximum rating of 50 bhp or less <u>or</u> that have an annual throughput less than 2 mmscf per year be exempt from the requirement to measure emission flow rate from rod packing or seal vents. A compressor operating with a throughput of 3.8 scfm (equivalent to 2 mmscf per year of continuous, constant rate operation) would need to leak nearly 50% of its throughput to exceed the 2 scfm leak threshold that triggers corrective action.

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95669 – Leak Detection and Repair

(b)(1) – This section states that the LDAR requirements of this rule are not applicable to:

> "Components, including components found on tanks, separators, and pressure vessels that are subject to local air district leak detection and repair requirements prior to January 1, 2018."

The issue here is semantics, i.e., what is meant by the phrase "subject to", and ensuring the rule language is consistent with our understanding of ARB's intent. I believe ARB's intent is to ensure that all components not already being inspected and repaired per a local LDAR program be "subject to" the requirements of Section 95669 while also avoiding the creation of unnecessarily redundant, overlapping, and burdensome record keeping and reporting requirements. Where local LDAR programs are already in place, but contain exemption provisions for certain components, some operators have chosen to voluntarily comply with the full requirements of the local program for all components, including components for which the local program provides an exemption (e.g., < 10 % VOC service). The question then becomes: Are the components that are eligible for exemption but not actually being exempted from the local program considered "subject to" the local program and, therefore, exempt from Section 95669? I believe the answer should be "yes", as long as the operator continues to <u>not</u> claim the exemptions available under the local program. To address this more clearly, I suggest that 95669(b)(1) be amended to read as follows:

> "Components, including components found on tanks, separators, and pressure vessels, where a local air district leak detection and repair program was in place prior to January 1, 2018, and the requirements of such program will be complied with after January 1, 2018, including components otherwise eligible for exemption from the local program.

This will allow operators to avoid unnecessarily redundant and overlapping record keeping and reporting requirements (i.e., reporting similar, but different data to two different agencies) by choosing to comply with the local program even for components that would otherwise be exempt from the local program (e.g., components in <10% VOC service). If this recommendation is not accepted, operators with this situation will be subjected to considerable redundant, overlapping, and confusing record keeping and reporting requirements, complicated by different definitions of "component", different leak thresholds, different exemptions, etc. In addition, if our suggestion above regarding how to interpret "facility" is not accepted, there will also be differences in the "facilities" for which data must be reported, requiring different sorts of basic data to fulfill reporting requirements for two different programs. Managing an LDAR program for thousands, tens of thousands, or even hundreds of thousands of components is already a significant effort. Complicating it with overlapping, redundant, and inconsistent requirements and definitions in another regulation will make program management unnecessarily burdensome.

(b)(6) – If components are in compressed air service, the composition of the component should not be a factor. I suggest the unnecessary term "stainless steel" be deleted from this exemption.

(b)(7) – The MRR and Subpart W exempt "tubing systems equal to or less than one-half inch diameter" from consideration when quantifying and reporting emissions under those regulations. The exemption in 95669(b)(7) inserts the qualifier "stainless steel" in this exemption. I suggest deleting the qualifier "stainless steel". Narrowing this exemption from the one provided in the MRR and in Subpart W will cause operator confusion in record keeping and reporting and, thus, create potential for unintentional non-compliance. It will also likely cause confusion and errors when agencies attempt to interpret, use, and compare data reported in accordance with the different regulations.

(f) - The requirement to quantify a leak within 24 hours is overly burdensome for many locations and will often involve additional vehicle trips and expense for overtime work. I suggest an allowable leak quantification period of 72 hours to ensure efficient use of resources, eliminate unwarranted vehicle trips (and the associated emissions) and avoid unnecessary overtime expense.

(o) – Compliance with Leak Detection and Repair Requirements. This subsection specifies that exceedances of the allowable number of allowable leaks or the 50,000 ppmv leak standard "during any inspection period as determined by the ARB Executive Officer or by the facility owner or operator" …. "shall constitute a violation this subarticle". To consider an owner or operator to be in violation when the results of a self-inspection indicate an exceedance of a standard is excessive and unnecessary. The goal of an LDAR program should be to ensure that operators actively identify and repair leaking components. Operators should be encouraged and recognized for efficiently performing self-inspections and promptly repairing leaking components without being subjected to enforcement for doing so. South Coast AQMD recognized this when they implemented their LDAR rule – Rule 1173. Rule 1173(d) specifies that operators will be in violation of the rule only if exceedances of defined leak standards are detected during a <u>District</u> inspection. I suggest the phrase "or by the facility owner or operator" in subsections (o)(2), (o)(3), and (o)(4) be deleted.

<u>95670 – Critical Components</u>

(b) – The phrase "and that shutting down the critical component would result in emissions greater than the emissions measured from the component" is not reasonable. Shutting down a critical process unit will generally not cause additional emissions, but will generally cause production to be curtailed, which results in loss of revenue. So, the criteria for a critical component should be (in addition to an impact to safety or reliability of the system) a threshold for the amount of revenue that would be lost if the critical component / process unit must be shut down to effect repairs. The threshold should be approximately equivalent to the cost-effectiveness of the LDAR requirements in the proposed rule (i.e., $15 of lost revenue per MT CO2e to be reduced?).

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95672 – Reporting Requirements

See comments below for "Appendix A" and "Appendix C".

95673 – Implementation

(b)(1)(A) – This section states: "This requirement applies to facilities or equipment upon issuance of any new local air district permit covering these facilities or equipment, or upon the scheduled renewal of an existing permit covering these facilities or equipment."

Will operators be required to submit applications to have local air districts modify existing permits prior to scheduled (e.g., annual) permit renewals? If yes, this imposes significant fees (approximately $1,500 to $7,000 per permit in South Coast AQMD) that do not appear to have been considered in determining the cost impacts of this regulation.

Whether operators are required to submit applications or not, there will likely be instances where local air districts are unable to issue updated permits within the required timeframe. In such cases, operators need assurance they will not be in violation if the local air districts fail to issue updated permits in the required timeframe.

(b)(2)(A)(3)(c) – Please refer to our general comments regarding throughputs and flash emission calculations.

(b)(2(B) – If changes occur late in the year, it may not be practical to report such changes by "January 1 of the calendar year after the year in which any information required by this subarticle has changed". A more reasonable reporting deadline would be March 1, instead of January 1, of the calendar year after the year in which any information required by this subarticle has changed.

Appendix A – Record Keeping and Reporting Forms

General – Applicable to multiple reporting forms

> Facility Name – Please refer to the comments regarding "Applicability" and the definition of "facility" above.
>
> Throughput - Please refer to the "General comments regarding throughput and flash emission calculations" above.

Table A1 – Flash Testing Record Keeping and Reporting Form

> Days in Operation per Year – Consistent with the comments on throughput values, I suggest this should be the number of days in the year during the prior calendar year.

Pressure Vessels – Is this field intended to be only pressure vessels that are used as separators in separator / tank systems? Or should it also include other pressure vessels such as small liquid knock-out vessels / scrubbers associated with gas compressors?

Separators – Should this field include pressure vessels used as separators? Should it include sumps that are used as separators?

Sumps – Should this field include sumps that are also counted as separators?

Table A4 – Leak Detection and Repair Inspection Record Keeping and Reporting Form

Inspection Date – Note that larger facilities require more than one day to complete an inspection and the inspection days may not always be consecutive. So expect to see multiple dates and / or date ranges entered in this field.

Table A5 – Component Leak Concentration and Repair Record Keeping and Reporting Form

Inspection Date – Same comment as above for Table A4.

Instrument Calibration Date – For larger facilities, expect to see multiple dates entered in this field as inspections may occur over a period of several days, which are not always consecutive.

Table A6 – Reporting and Registration Form for Facilities

Number of Wells – I suggest this should be the number of active producing wells (i.e., excluding injection wells and inactive production wells) at the end of the prior calendar year (similar to our comments regarding "throughput"). Similar to throughput values, the number of wells changes frequently. Also, note that the number of crude oil wells and the number of produced water wells will usually be the same number (unless the facility has water source wells that are "produced water wells").

Appendix C – Flash Test Procedure

General - ARB staff have stated that the flash analysis testing procedure prescribed in this regulation is "the same, but modified" as compared to the flash test procedure prescribed in the MRR. I do not understand how the procedure can be both "the same" and "modified". To avoid unnecessary redundancy and expense, I believe the flash analysis testing required to comply with both regulations should be identical and the required record keeping forms for flash analysis testing should be the same for both regulations. Alternatively, the proposed regulation should state that the prescribed flash test procedure is acceptable for use in calculating and reporting emissions per the MRR.

Section 5.5 – The term “steady state” is used to describe the temperature and pressure of the separator and tank system being sampled. The term “steady state” is not defined within the procedure itself nor in the proposed regulation. The Merriam-Webster online dictionary defines “steady state” as:

> “a state or condition of a system or process (as one of the energy states of an atom) that does not change in time; *broadly* **:** a condition that changes only negligibly over a specified time”

Field production systems, including separator and tank systems and especially systems using a temporary portable pressurized separator for flash analysis sampling, rarely, if ever, operate at “steady state” conditions. So it is not practical to require such a condition for flash analysis sampling. I request that ARB either (a) delete the term “steady state” or replace it with a more reasonable term, e.g., “at temperature and pressure conditions that are varying as little as practical”.

<u>Staff Report</u>

Executive Summary and page 2 of the Staff Report

In the third paragraph on the first page of the Executive Summary, it is stated: “Oil and gas systems are responsible for approximately 15 percent of methane emissions in the state.” But in the last paragraph on page 2 of the main section of the Staff Report (Section I-A-2), it is stated: “Oil and gas systems contribute approximately 13 percent of statewide methane emissions”. The two statements appear to be in conflict.

Page 23:

> The first sentence under “ (e) – Natural Gas Processing Plants “ states:
>
> “Natural gas processing plants process raw natural gas and separate the various hydrocarbons and fluids from the raw natural gas, to produce what is known as “pipeline quality” dry natural gas.”
>
> Please note that not all natural gas processing plants produce “pipeline quality” gas. Some produce gas that does not qualify as “pipeline quality”, yet is suitable for use as fuel, for re-injection in the subsurface, etc.

Page 27:

> The second sentence of the third paragraph on this page states:
>
> “In addition, the proposed regulation establishes an emissions standard for non-field compressors, which, if exceeded, in addition to any applicable penalties, require the compressor be repaired, replaced, or the gas must be collected and routed into the vapor collection system.”

The term "non-field" in this sentence is undefined and unclear.

Also, I suggest the sentence be replaced with the following two sentences:

"In addition, the proposed regulation establishes an emissions standard for compressors at certain facilities, which, if exceeded, in addition to any applicable penalties, require the compressor be repaired, replaced, or the gas must be collected and routed into the vapor collection system. The affected facilities are those in the following sectors / segments: natural gas underground storage, natural gas gathering and boosting stations, natural gas processing plants, and natural gas transmission compressor stations."

Page 29:

Footnote 40 to Table 5 includes the sentences:

"Also includes remaining emissions from sources controlled by districts. For example, tank measures are 95% effective so there are 5% of the original emissions remaining."

It is unclear what this footnote means.

Page 34:

The summary of Section 95668(a)(2)(E) includes the phrase "for up to 90 calendar days following completion". I believe that inclusion of the words "following completion" is in error and should be deleted. [Section 95668(a)(2)(E) of the rule does not include the words "following completion".]

Page 48:

The heading for this section ("Centrifugal Natural Gas") should be "Centrifugal Natural Gas <u>Compressors</u>".

Page 57:

The first sentence in the "Rationale of Section 95669(b)(7)" says "…… that have been previously testing." I believe it should say "…… that have been previously tested".