Western States Petroleum Association
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Catherine Reheis-Boyd
President

May 22, 2015

Mr. Jim Nyarady
Manager, Oil and Gas Section
California Air Resources Control Board
1001 I Street
Sacramento, CA 95814

Re: WSPA Comments on draft Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Operations – Second Round

Dear Jim:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California and four other western states. WSPA appreciates this opportunity to provide this second round of comments on the proposed regulatory language published by the California Air Resources Board (ARB) on April 22, 2015 and presented by ARB staff on April 27 and 29, 2015 at the Public Workshops regarding ARB's draft Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Operations.

WSPA and WSPA member companies, as key stakeholders, have engaged with the ARB in the regulation development and implementation process. As the WSPA member companies each have existing air quality compliance programs, it is important that the final regulation be consistent with current and successful local, state, and federal air quality regulations.

The following attachments provide focused assessments of WSPA and WSPA member company concerns regarding the more complex elements of the proposed regulatory language. This comment letter is intended to supplement the initial WSPA comments submitted on May 15, 2015. Given the extensive technical comments in the WSPA comments, we strongly recommend another round of informal review of the draft regulatory language.

Thank you for your consideration of WSPA's comments. If you have any questions, please contact me at this office.

Sincerely,

WSPA Comments
General Rule Implementation and Applicability

Issue 1

Standardized Regulatory Impact Assessment (SRIA)

The SRIA provides emissions estimates from the different source categories in California. WSPA is providing a comparison of emissions estimates from GHG MRR (except for Recirculation Tanks and New LDAR) that covers approximately 80% of California's emissions sources.

Proposed Category For Control	Emissions before Regulation (tonnes CO2e)	GHG MRR (tonnes CO2e	% Difference
Uncontrolled Oil and Water Separators and Tanks	265,000	261,784	1%
Reciprocating Compressors	476,000	12,835	3609%
Centrifugal Compressors	20,000	484	4036%
Pneumatic Devices and Pumps	167,000	87,919	90%
Recirculation Tanks For Well Stimulation Completions	25,700	8,092	218%
Liquids Unloading	400	-	100%
Components under New LDAR Program	2,900	1,056	175%
TOTAL	957,000	372,169	157%

Based on the ARB's GHG emissions inventory that is verified by ARB-certified third party auditors, WSPA finds significant differences from the emissions estimates used for this regulation. Since the GHG MRR program covers 80% of the emissions, the emissions estimates for the rest of the non-MRR covered (20%) are expected to be smaller. Assuming conservative emission rates similar to the 80%, the total state-wide emissions from these source categories are expected to be less than 500,000 MT CO_2e (20,000 MT CH_4). However, the emissions estimates provided in the SRIA are almost twice the amount suggested by the MRR program. As a result, these estimates can skew the cost to benefit ratio by more than double.

Recommendation 1

WSPA recommends that ARB use the most accurate sources of emissions when determining the emissions reductions, benefits achieved, and cost-effectiveness. Since most of the source categories in the proposed regulation overlap with the inventory collected under CA GHG Mandatory Reporting Regulation, ARB can use this third-party verified data to develop current estimates for those source categories and additional benefits of the proposed regulation. For facilities that do not report under GHG MRR, WSPA recommends that ARB use the MRR data to extrapolate the emissions from the facilities that do report under MRR.

WSPA Comments
Leak Detection and Repair

Issue 1

Emissions

In Table 1 of the ARB Standardized Regulatory Impact Assessment (SRIA) dated April 29, 2015, it is stated that the emissions from leaks covered by the proposed regulation will lead to a reduction of approximately 1,200 MT CO_2e. A copy of the table is provided below.

Table 1: Summary of Annual Emissions and Reductions for O&G Proposal (2018 and forward)[5]

Proposed Category For Control	Emissions before Regulation (tonnes CO_2e)	Reductions from Proposal (tonnes CO_2e)
Uncontrolled Oil and Water Separators and Tanks	265,000	252,000
Reciprocating Compressors	476,000	143,000
Centrifugal Compressors	20,000	10,700
Pneumatic Devices and Pumps	167,000	124,000
Recirculation Tanks For Well Stimulation Completions	25,700	24,400
Liquids Unloading	400	350
Components under New LDAR Program	2,900	1,200
Remaining Venting and Fugitive Emissions for Proposed Regulated Categories (includes equipment controlled under existing district programs, such as already-controlled tanks and components)	41,000	0
TOTAL	**998,000**	**556,000**
All Other Oil & Gas Venting and Fugitive Sources (e.g., compressor blowdowns, dehydrators, etc.)	341,000	0
GRAND TOTAL	**1,339,000**	**556,000**

WSPA's independent emission reduction calculations result in comparable value (approximately 1,100 MT CO_2e) for new LDAR components (>10% VOC by weight) with a GWP of 25 for Methane.

Recommendation 1

WSPA believes the total emissions covered by this regulation are negligible especially considering the existing robust local air district I&M programs. With additional component testing requirements, additional mobile vehicle emissions would have to be added to achieve these minimal reductions. WSPA recommends that mobile vehicle emissions be accounted for when determining the cost-effectiveness of this regulation.

Issue 2

Cost Effectiveness

Although the SRIA explains cost-effectiveness for the entire regulation, cost-effectiveness at the source category level is not provided. Assessing cost-effectiveness at the source-category level helps to identify the source categories where the costs of control measures are reasonable in relation to the predicted emission reductions. Additionally, assessing source-specific impacts highlights situations, such as LDAR programs, where ongoing costs are higher and consistent from year to year with continued inspections.

LDAR programs are very expensive due to costs associated with inspections, component tagging, and recordkeeping programs. Based on experience with the implementation of district programs, WSPA estimates additional LDAR costs associated with the proposed regulation will range from $0.5MM to $1MM per year for a facility. Industry wide, WSPA estimates that the proposed ARB LDAR program will cost approximately $8MM to $10MM every year. This is equivalent to $6,000 - $8,000 per MT CO_2e compared to $40 per MT CO_2e stated by ARB in the SRIA.

In the SRIA document, ARB estimates that approximately 1.1 million standard cubic feet of gas would be recovered due to the implementation of this program. As a result, SRIA describes a benefit of $4.8 million per year. However, WSPA's calculations using the data provided in the SRIA result in a significantly different benefit (by an order of 1,000).

At $4.10 per Mscf of natural gas (where Mscf means 1,000 standard cubic feet),

$4.10 per 1,000 scf * 1,100,000 scf/yr = $4,510/yr.

In addition, ARB is assuming that the gas recovered is of same quality (high BTU/scf) as the commercial quality natural gas that can be sold at $4.10 per Mscf. Since ARB is targeting components with VOC concentration <10% by weight, the gas recovered is expected to be of very low quality (low Btu/scf) and it would not be of the same value as commercial quality gas. As a result, the benefit from gas recovery is significantly over-estimated.

Recommendation 2

WSPA recommends that ARB review the cost-effectiveness calculations in the SRIA and provide transparent calculations and unit clarifications that result in a revised cost-effectiveness determination or a clear demonstration of how the annual benefit of $4.8 million was derived.

Issue 3

Applicability

As outlined in our comment letter submitted on May 15 (Comment Letter 1), WSPA understands that ARB's intent is to implement an LDAR program that aligns with the existing local air district programs but also covers components that are currently not in a District LDAR program due to "< or = 10% VOC by weight" exemption. However, WSPA is concerned that the proposed regulation does not clearly identify ARB's intent nor does it align with local air district programs. As written, the regulation can be interpreted to require duplicative monitoring of components currently subject to the existing local air district LDAR programs.

In addition to the exclusions discussed in Comment Letter 1, WSPA believes that the following exclusions (for e.g. SJVAPCD Rule 4409) should also be provided:

- Components handling commercial quality natural gas exclusively

  Distribution of commercial quality natural gas is purchased by industrial consumers, residential homes, businesses, schools, and other institutions for end use. We are of the understanding that ARB's intent with this regulation is not to include natural gas distribution lines that deliver commercial quality gas to consumers. There is no difference between the commercial lines used by oil and gas operations and those used to serve any other business or home (which would be exempt from these regulations).

- Components exclusively handling streams which have methane concentration less than 10 percent by weight (<10 wt%).

  Although WSPA understands that the purpose of this regulation is to minimize methane leaks, there may be gas streams in the field that are not primarily methane, such as non-hydrocarbon streams. However, these lines may contain trace amounts of methane that are not significant enough to be detected.

<u>Recommendation 3</u>

In order to clarify applicability of the proposed regulation to distribution lines that provide commercial quality gas to different industrial and residential consumers, WSPA recommends ARB provide exclusions for commercial quality gas. WSPA also believes that it would not be efficient to conduct regular testing of lines merely because they contain a trace amount of methane. As such, WSPA recommends that ARB include a threshold for minimum amount of methane in the stream.

<u>Issue and Recommendation 4</u>

Definitions

In order to clarify the regulatory terms and to add exclusions stated above, WSPA recommends that ARB add the following definitions (both terms are defined in SJVAPCD Rule 4409):

- *Commercial Quality Natural Gas*
- *Gas/Vapor Service*

<u>Issue 5</u>

Leak Thresholds

ARB has proposed 1,000 PPM as the threshold for minor leak. During the workshops, other stakeholders have requested ARB to reduce the thresholds to match existing regulations. WSPA is concerned about the impact of very low thresholds on facilities that ARB is planning to target for small amounts of emission reductions that would be achieved with such low thresholds.

There is no technical basis for the assumption that a leak threshold below 10,000 ppm will result in significant emission reductions. In a study performed by California State University Fullerton (CSUF) under a California Energy Commission Project, it was clearly illustrated that there is no correlation between ppm determined through Method 21 and leak flow. Figure 5.2.1.1 of the

CSUF report provides a graph representing the concentration vs. leak rate data collected. The same data is separated into concentration ranges in Table 5.2.1.2. The Figure and Table are included below:

Figure 5.2.1.1: Leak Rates vs. Screening Values of All Leaking Components

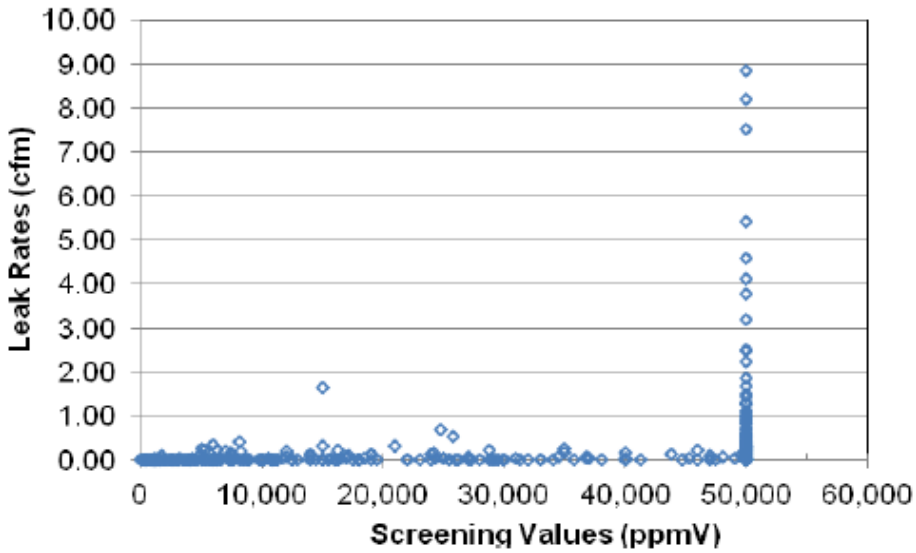

Table 5.2.1.2: Leak Rates vs. Screening Values in Four Ranges (All Components)

		Leak Rate (cfm)				
SV (ppmV)	Count	Min	Max	Median	Average	Geomean
100-999	16	0.005	0.005	0.005	0.005	0.0050
1,000-9,999	101	0.005	0.410	0.005	0.027	0.0085
10,000-49,999	94	0.005	1.640	0.020	0.070	0.0198
≥50,000	167	0.005	8.850	0.110	0.552	0.0901
Total	378	0.005	8.850	0.010	0.269	0.0291

Using the CSUF data provided in Table 5.2.1.2, the total leak rate can be calculated. Using these total leak rates, the potential emission reduction can be calculated for each concentration threshold.

Table 1. Leak screening values and expected percentage of leaks as determined from the CSUF study.

Screening Value (ppmv)	Count	Avg cfm	Total cfm for All Leaks	Percent of Leakage
<=999	16	0.005	0.08	0.08%
1,000 to 9,999	101	0.027	2.73	2.68%
10,000 to 49,999	94	0.07	6.58	6.48%
50,000+	167	0.552	92.18	90.76%
Total	378	0.269	101.57	100.00%

As seen in the table above, greater than a 90% reduction would result from the control of leaks above 50,000 ppm. If 10,000 ppm were to be selected as the threshold, greater than a 97% reduction would be realized. Conversely, a ppm threshold of 1,000 ppm would only result in less than 2.7% additional emissions capture beyond a 10,000 ppm cutoff and an additional drop to 500 ppm, as suggested by some stakeholders in ARB workshops, is effectively negligible.

As shown through these calculations, a ppm threshold below 10,000 ppm is not an effective method for emissions reduction nor is it cost effective due to the compliance costs associated with an LDAR program as discussed above. Therefore, most existing regulations consider 10,000 PPM as the threshold. Below is a table of comparison of existing regulatory leak thresholds:

Segment	Production		Processing	
Leak Type	Minor Leak	Major Leak	Minor Leak	Major Leak
SJVUAPCD	200 - 10,000 ppm	>10,000 ppm	100 - 10,000 ppm	>10,000 ppm
SCAQMD	>10,000 ppm		>10,000 ppm	
BAAQMD	>10,000 ppm		>10,000 ppm	
CA GHG MRR	>10,000 ppm		>10,000 ppm	
CO GHG	>10,000 ppm		>10,000 ppm	
Quad O	None		500 ppm	

Although SJVAPCD specifies lower thresholds, these thresholds have evolved over several decades beginning with higher thresholds (20,000 ppm) before the thresholds were lowered. Facilities with existing LDAR programs must comply with existing lower thresholds regardless of the thresholds proposed in this regulation.

In addition, WSPA is concerned that applying such low thresholds abruptly to facilities located in attainment areas that have never had an LDAR program (ARB's primary target with this regulation) will be extremely labor-intensive and burdensome on operators. LDAR programs involve the development of an operator management plan, training of operators with both testing instrumentation and audio-visual inspections, component tagging, record-keeping, and repair programs. The additional costs associated with lower thresholds would be substantial particularly when considering the incremental amount of emission reductions achieved with lower thresholds.

Recommendation 5

In order to improve cost-effectiveness, minimize the burden on operators and align with existing major regulations, WSPA recommends that ARB define a leak at 10,000 PPM and a major leak at 50,000 PPM for facilities that are subject to existing local air district LDAR programs.

For facilities that are located in attainment areas and are not subject to an existing LDAR program, WSPA recommends that ARB allow the facilities to gradually phase into the program by defining a higher threshold in the initial phases. WSPA suggests that ARB begin at 50,000 PPM threshold for these facilities (which will provide greater than 90% reductions). WSPA's suggestions on "phasing in" of these facilities are provided below in the Regulatory Language Change Recommendation section.

Issue 6

Inspection Frequency

ARB has proposed annual Method 21 inspections or quarterly optical gas imaging (OGI) inspections in the current proposal. Other stakeholders have suggested more frequent testing during ARB workshops in April 2015.

An LDAR program is a step change for a facility. Initial annual surveys will identify larger leaks and representative reductions will be realized in the first year of the program. Operators are trained to conduct audio-visual (see, smell, hear) inspections in addition to conducting the required Method 21 testing. In subsequent years, the incidence of leaks will decrease significantly as observed during the implementation of District LDAR programs. Thus, requiring operators to conduct more frequent testing (particularly when leak rates are very small) will lead to significant costs but will not provide a corresponding benefit to the overall program.

Recommendation 6

WSPA recommends that ARB determine the frequency of inspections based on leak rates instead of a blanket requirement. WSPA also recommends that ARB allow operators that have implemented very robust LDAR programs and demonstrated improvement in their programs with very low leak rates to have a lower inspection frequency.

Issue 7

Repair Durations

ARB has proposed stringent repair durations (3 days for 10,000 PPM and 1 hour for critical components) that may not be achievable in certain instances. In production operations where the components can be spread out in several fields far away from field office locations, operators may need to travel several hours before they can reach the location where a leak may have been found. In addition, vendor service delays outside of operator control may cause delays in repair. The very short repair durations are also very burdensome on facilities that will be subject to these requirements for the first time.

Recommendation 7

WSPA recommends that ARB increase the repair durations to allow reasonable time for operators to address the leaks. As such, WSPA recommends that ARB use existing regulations (such as SJVAPCD Rule 4409) as the basis for reasonable repair durations.

Regulatory Language Change Recommendation

Incorporating the comments and recommendations cited above, WSPA suggests the following language changes (new language in red plus strikeouts) to the proposed regulation:

Section 95212

Commercial Quality Natural Gas: a mixture of gaseous hydrocarbons with at least 80 percent methane by volume (≥ 80 vol%) and less than ten percent by weight (<10 wt%) VOC and meets the criteria specified in Public Utilities Commission (PUC) General Order 58-A.

Gas/Vapor Service: a component is considered to be in gas/vapor service when the fluid in contact with the component contains methane and the fluid is primarily in gaseous state at operating conditions.

(20) "~~Major~~ Leak" means the detection of total gaseous hydrocarbons in excess of the following thresholds as methane above background measured using EPA Method 21 (40 CFR 60, Appendix A) –

(a) For facilities with existing local air district LDAR requirements - 10,000 ppmv;

(b) For facilities located in attainment areas that do not have existing local air district LDAR requirements - the following thresholds will apply during the stated years

Calendar Year	Leak Threshold (ppmv)
2017 - 2018	50,000
2019 - 2020	20,000
2021 and beyond	10,000

(21) "Major leak ~~over 50,000 ppmv~~" means the detection of total gaseous hydrocarbons in excess of 50,000 ppmv as methane above background measured using EPA Method 21 (40 CFR 60, Appendix A).

~~(22) "Minor leak" means the detection of total gaseous hydrocarbons in excess of 1,000 ppmv as methane above background measured using EPA Method 21 (40 CFR 60, Appendix A).~~

Section 95213

(i) Leak Detection and Repair

(1) Leak detection and repair requirements do not apply to the following unless required by the local air district:

(A) Components that are buried below ground.

(B) One-half inch and smaller stainless steel tube fittings including those used for instrumentation.

(C) Components incorporated in lines operating under negative pressure or below atmospheric pressure.

(D) Components and piping located downstream from the point where crude oil or natural gas transfer of custody occurs, including components and piping located outside the location boundaries of natural gas compressor stations and underground storage operations.

(E) Temporary components or equipment used ~~for general maintenance purposes and used~~ less than 300 hours per calendar year.

(F) Components which are unsafe to monitor when conducting EPA Method 21(40 CFR 60, Appendix A) measurements and as documented in a safety manual or policy and with approval of the local air district.

(G) Components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150°C.

(H) Components handling liquids with 90 percent by volume or greater (≥90 vol%) water concentration.

(I) Components handling commercial quality natural gas exclusively.

(J) Components exclusively handling streams which have methane concentration less than 10 percent by weight (<10 wt%).

(2) Except as provided in section 95213(i)(1), components ~~containing~~ in ~~natural~~ gas/vapor service in source categories listed in section 95211 shall be inspected at the frequency specified below unless a more stringent inspection time period is required by the local air district:

(A) For calendar year 2017, conduct at least one inspection and measurement of components using methods specified in 95213(i)(3). Operators already conducting LDAR to meet local air district requirements meet the requirements of this section for the components that are tested. For components that are not required to be tested under local air district LDAR program but are subject to this section, operators must conduct at least one inspection for calendar year 2017.

(B) For calendar year 2018 and beyond, the facility must conduct inspections and measurements during the calendar year at the frequency determined according to 95213(i)(2)(B) and 95213(i)(2)(C) using the leak rate determined from the prior inspection period.

The operator must calculate the leak rate for the prior period (p-1) as follows:

$$Prior\ Period\ Leak\ Rate_{p-1} = \frac{Total\ count\ of\ leaks_{p-1}}{Total\ count\ of\ components\ tested_{p-1}}$$

(C) Determine the frequency of inspection for calendar year 2018 and beyond as follows:

$Prior\ Period\ Leak\ Rate_{p-1}$	$Minimum\ Inspection\ Frequency$
<5%	Annual
5 – 10%	Semi-Annual
>10%	Quarterly

(D) Operators already conducting LDAR at the frequency determined using 95213(i)(2)(B) to meet local air district requirements also meet the requirements of this section for the components that are tested. For all others components subject to this regulation, operators must conduct inspections at the frequency determined according to Section 95213(i)(2)(E) and Section 95213(i)(2)(F).

(E) An operator who demonstrates leak rates <5% for calendar year 2017 can conduct annual testing unless the leak rate increases to 5% or greater, in which case the operator must follow 95213(i)(2)(F).

(F) If the leak rate is 5% or greater for calendar year 2017 or any measurement period beyond, the operator is required to conduct inspections at the frequency determined according to Section 95213(i)(2)(C). An operator can request ARB's approval for reduced inspection frequency according to thresholds specified in Section 95213(i)(2)(C), if the operator can demonstrate the lower leak rates for three consecutive measurement periods.

(3) Inspections and measurements specified in 95213(i)(2) must be conducted according to one of the following methods:

(A) Inspect and measure components for total hydrocarbon concentration in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A); or,

(B) Inspect components using an optical gas imaging (OGI) instrument that detects the presence of hydrocarbon vapors or meets criteria specified in 40 CFR part 60 for optical gas imaging instruments. When using this method, within two (2) calendar days of initial leak detection of a component, or within 14 calendar days of initial leak detection of an inaccessible component, the operator must measure the leak for total hydrocarbon concentration in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

~~(A) Annually, inspect and measure components for total hydrocarbon concentration in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A); or,~~
~~(B) Quarterly, inspect components using an optical gas imaging instrument that detects the presence of hydrocarbon vapors or meets criteria specified in 40 CFR part 60 for optical gas imaging instruments; and,~~
~~1. Within two (2) calendar days of initial leak detection of a component, or within 14 calendar days of initial leak detection of an inaccessible component, measure the leak for total hydrocarbon concentration in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).~~

(4) ~~(3)~~ Beginning 1/1/2017, any component subject to this section inspected and measured in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A) and is found to have a total hydrocarbon concentration above the following standards shall be repaired within the time period specified unless a more stringent leak standard or a more stringent repair time period is required by the local air district:

~~(A) Fugitive leaks with a measured total hydrocarbon concentration above 1,000 ppmv but not greater than 10,000 ppmv shall be successfully repaired or removed from service within seven (7) calendar days of initial leak detection. A time extension to make repairs not to exceed seven (7) calendar days may be granted by the local air district.~~

(B) Fugitive leaks with a measured total hydrocarbon concentration above ~~10,000 ppmv~~ the leak thresholds defined in 95212(a)(20) shall be successfully repaired or removed from service within five (5) ~~three (3)~~ business days of initial leak detection. A time extension to make repairs not to exceed two (2) calendar days may be granted by the local air district.

(C) Fugitive leaks with a measured total hydrocarbon concentration above 50,000 ppmv shall be successfully repaired within two (2) calendar days.

(D) Critical components found to be leaking ~~above the minor leak threshold~~ and that are technically infeasible to repair without a process unit shutdown, or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, shall be repaired to minimize leakage to the maximum extent possible within twelve (12) ~~one (1)~~ hours of detection and the repair of such components shall be completed by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

(5) ~~(4)~~ Upon detection of a component that is measured above the standards specified in section 95813(i)(4~~3~~), the owner or operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the component until all of the following conditions are met:

(A) The leaking component has been repaired or replaced; and,

(B) The component has been re-inspected and determined to be leak free when measured in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

Section 95214

Leak Detection and Repair

(6) For a minimum of five (5) years, maintain a record of leak detection and repair activities that include the following:
(A) Date, name, and location of operation inspected.
(B) Type of component found leaking.
(C) Measured total hydrocarbon concentration (ppmv).
(D) Date of repair or date(s) of attempted repair.
(E) Measured total hydrocarbon concentration (ppmv) after leak is repaired.
(F) Total number of components inspected, total number of leaks identified, and percentage of leaking components.
(G) Current record identifying all components awaiting repair.
(H) Type of leak detection instrument(s) used to conduct the inspection including date and time of instrument calibration(s) as required by the instrument manufacturer.

Section 95215

Leak Detection and Repair

(4) Annually, report a summary of results of leak detection and repair activities as described in Appendix C, Table 4 to the local air district and/or ARB using the contact information provided in section 95215(b).

WSPA Comments
Circulation Tanks for Well Stimulation Treatments

Issues

Process Clarification

In order to accurately quantify the emissions from circulation tanks used in well stimulation treatments, it is critical to understand the processes in which the circulation tanks are used and differences from processes described in some other studies (e.g., USEPA White Paper on Oil Well Completions). During the Methane Rule Workshops held by ARB on April 27 and 29, 2015, several stakeholders were confused on ARB's intent to control circulation tanks and incorrectly assumed that ARB was trying to control emissions from flowback. WSPA is providing the description below to help clarify ARB's intent of controlling circulation tanks and associated emissions. A typical well stimulation treatment follows the steps described in Figure 1.

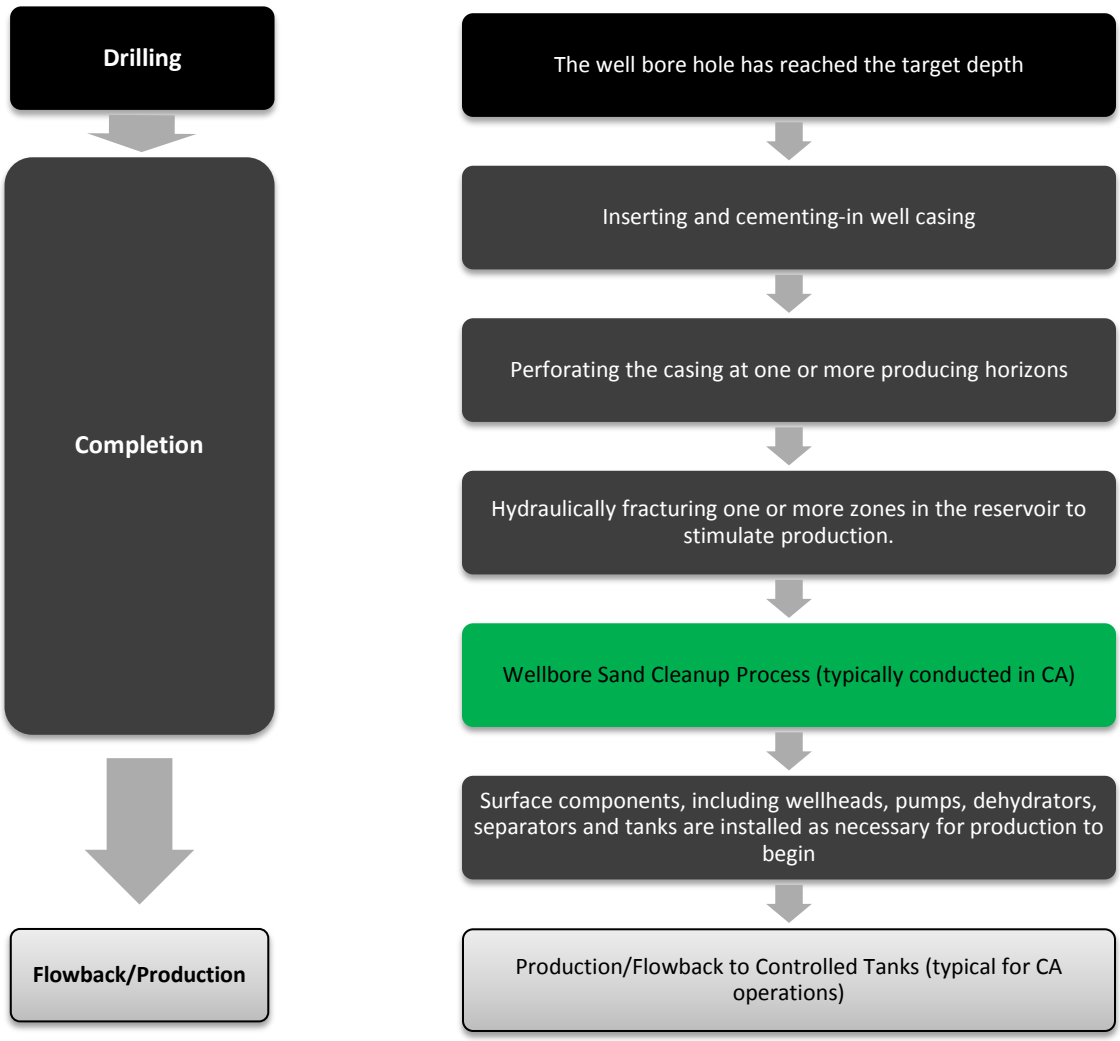

Figure 1. Typical high level steps involved in California's oil well completion activities with well stimulation treatments.

Typically, in non-California operations (as described in USEPA white paper for oil completions with hydraulic fracturing) the flowback[1] from the hydraulically fractured wells is directed to open tanks or pits. ***However, California operators normally direct production flowback into the existing and permanent production tank systems that are typically required to have vapor recovery systems.*** These systems, which the proposed regulation addresses separately, have overall capture and control efficiency rates ranging from 90% to 99.5%. The gas can be combined with fuel streams either for combustion, further gas processing, gas injection, or gas sales. Since these activities meet the definition of Reduced Emissions Completions (RECs) in the USEPA white paper, most California hydraulically fractured oil well completions are RECs or green completions.

California's oil fields generally produce very little gas (an average of 6 – 10 scf/bbl) due to low reservoir pressures, preventing the reservoir fluids from entering the wellbore without a lifting mechanism. As a result, operators have to conduct additional steps during oil well completions following well stimulation treatments (the wellbore sand cleanup process). This process is carried out separately prior to the flowback/production phase in order to clean out the sand from the wellbore. This separate process is unique to oil production fields where the reservoir pressures are very low and/or the gas to oil ratio (GOR) is very small. This is in contrast to fields with a higher GOR because the pressure in these wells will carry the sand out of the well without the need for the separate wellbore sand cleanup process.

During the wellbore sand cleanup process, the well is balanced or over-balanced to prevent the reservoir fluids from entering the wellbore. This means that the wellbore is kept at a pressure at or above the geologic formation pressure by the weight of the fluids circulated into the wellbore. A mixture of fresh or produced water is circulated into the wellbore and the sand is lifted and pumped out. A small temporary portable tank is used during this process to circulate the water and to separate the sand from the water. After the wellbore cleanup process is complete, the well is put into production during which the flowback and production are directed to controlled permanent tank systems as described above.

A typical wellbore sand cleanup process includes 3 to 4 stages and lasts for approximately 8-16 hours. There are approximately 20 portable tanks in CA that are shared between operators for the approximately 800 events per year (the average number of wells stimulated with hydraulic fracturing). Operators acquire the needed expert services from trained personnel. One portable tank is usually onsite for the duration of an event. ARB is proposing that operators control emissions from these portable and temporary circulation tanks used in the wellbore sand cleanup process.

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[1] Definition source is USEPA White Paper on Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production (http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf)

Backflow is the phenomena created by pressure differences between zones in the borehole. If the wellbore pressure rises above the average pressure in any zone, backflow will occur (i.e., fluids will move back towards the borehole). In contrast, "flowback" is the term used in the industry to refer to the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.(http://www.glossary.oilfield.slb.com/) In California, the definition of "flowback" is often confused with frack fluid/water that is returned after a hydraulic fracturing job. Flowback fluids in California are be considered production fluids; because unlike other parts of the country, California fractured wells are typically put into operation after the hydraulic fracture event.

Emissions

Table 1 of ARB's Standardized Regulatory Impact Assessment (SRIA) dated April 29, 2015, states that the emissions controlled by the proposed regulation will lead to a reduction of approximately 24,400 MT CO_2e (or 976 MT CH_4) from all events in California. The estimated emissions are presumably based on testing conducted by ARB in Kern County from four (4) well stimulation events.

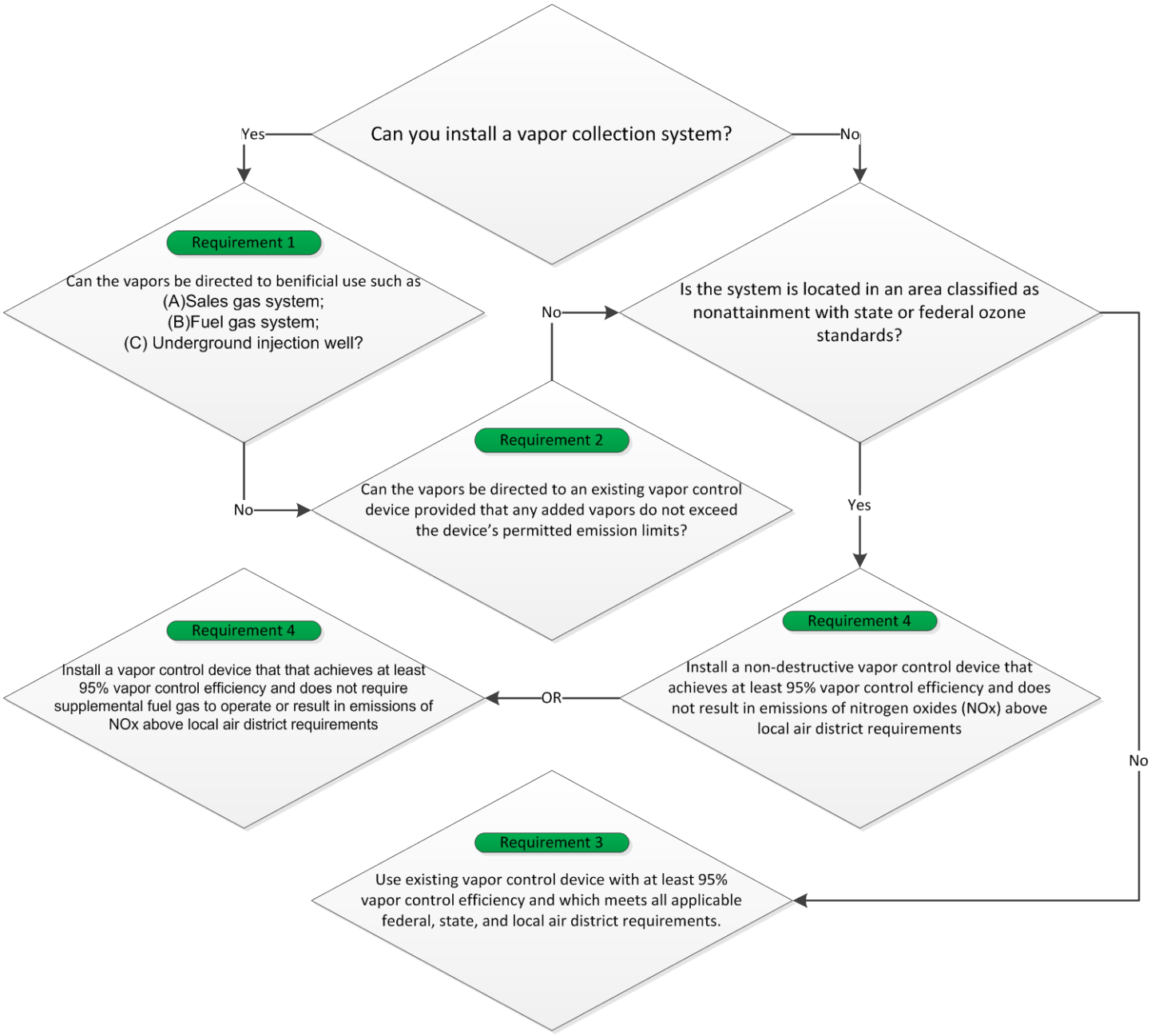
Table 1: Summary of Annual Emissions and Reductions for O&G Proposal (2018 and forward)[5]

Proposed Category For Control	Emissions before Regulation (tonnes CO_2e)	Reductions from Proposal (tonnes CO_2e)
Uncontrolled Oil and Water Separators and Tanks	265,000	252,000
Reciprocating Compressors	476,000	143,000
Centrifugal Compressors	20,000	10,700
Pneumatic Devices and Pumps	167,000	124,000
Recirculation Tanks For Well Stimulation Completions	25,700	24,400
Liquids Unloading	400	350
Components under New LDAR Program	2,900	1,200
Remaining Venting and Fugitive Emissions for Proposed Regulated Categories (includes equipment controlled under existing district programs, such as already-controlled tanks and components)	41,000	0
TOTAL	998,000	556,000
All Other Oil & Gas Venting and Fugitive Sources (e.g., compressor blowdowns, dehydrators, etc.)	341,000	0
GRAND TOTAL	1,339,000	556,000

Compared to ARB's estimates, WSPA calculations, from the same ARB testing, result in estimated annual statewide emissions of 100 MT CO_2e to 8,000 MT CO_2e with a GWP of 25 for methane. Average estimated emissions per event range between 0.2 MT CO_2e to 10 MT CO_2e (or 0.01 MT CH_4 to 0.4 MT CH_4). WSPA understands that in the absence of representative test data, ARB has applied conservative assumptions (almost 3 times the highest possible emissions using the test data). This results in significant over-estimation of state-wide emissions and associated emissions reductions. WSPA is concerned that the over-estimation of emissions will result in skewed state-wide cost-effectiveness analyses.

Existing Control Technologies

The proposed regulation identifies four control requirements for the temporary portable circulation tanks in the order of technical feasibility. These requirements are described in the following diagram.



As shown in the diagram, the requirements apply to all wellbore cleanup events regardless of the emissions from each event. WSPA is concerned about the technical feasibility of the proposed control technologies.

- Requirements 1 & 2 – Installing a vapor recovery system

As discussed above, the wellbore sand cleanup process after a well stimulation event lasts for approximately 8-16 hours. There is not enough pressure from these tanks to allow the gas to be introduced into a vapor recovery system. This would require a compressor (an additional combustion source) to boost the pressure of the gas from the tanks high enough to allow it to enter a vapor recovery system. Connecting a temporary process with small amount of gas to an

existing vapor recovery system with stabilized flow introduces oxygen into the system creating a safety risk of fire hazard or explosion of the entire tank farm.

The well may be located in a remote area where the existing piping/vapor recovery systems are unavailable or too far away. For an event that only lasts a few hours, it is inefficient to build permanent systems (like pipelines and compressors) to recover small amounts of gas. This construction process will also add emissions from those sources. WSPA is also concerned about the issues associated with permitting a portable tank being connected to an existing stationary vapor recovery system.

- Requirement 3 – Install a vapor control device with 95% efficiency in attainment areas

Most of the well stimulation events in California occur in Kern County which is an ozone non-attainment area. Therefore, this requirement will not be applicable to most of the events.

- Requirement 4 – Install a non-destructive vapor control device with 95% efficiency or a vapor control device with 95% efficiency and no supplemental fuel

There is no proven existing technology that can capture the small amount of gas/vapors from these events and control with a demonstrated efficiency of 95%. Technologies provided by the two vendors (who were consulted) have been used only for flowback and production processes where the amount of gas is significantly higher than the wellbore sand cleanup process. The two vendors have clearly stated that their technologies have not been tested or used in the wellbore sand cleanup process.

The volume of gas is expected to be very small from these events. A flare/thermal oxidizer would need supplemental fuel for pilot and purge because, in most cases, the permit conditions require operators to have auto-pilot to ensure that low amounts of gas are combusted.

None of the control technologies proposed above can be technologically achievable for most of the events taking place in California. The current proposed regulation has not considered the possibility of not being able to implement the options of control listed in Section 95213(c), especially where the gas volumes are low and fluctuating. As noted above, there are no existing control technologies that are proven to provide 95% capture and control of emissions from circulation tanks. The proposed “new” systems from vendors are yet to be tested or used in wellbore sand cleanup process and there are no guarantees that those systems will achieve the proposed capture and control requirements.

Cost Effectiveness

Although the ARB SRIA explains cost-effectiveness for the entire regulation, cost-effectiveness at the source category level is not provided. Assessing cost-effectiveness at the source-category level demonstrates that the regulation is focusing on the largest source categories. WSPA has identified significant issues related to the cost effectiveness analysis for this source category. According to ARB estimates, the cost effectiveness of the regulation is $40/MT CO2e based on a 20 year costs. The following cost analysis assumes that controls are proven to be technically feasible. WSPA does not believe this feasibility has been adequately demonstrated at this time.

$$\text{Total 20-year cost} = \$40/\text{MT } CO_2e \times 24{,}400 \text{ MT } CO_2e/\text{yr} \times 20 \text{ years} = \$19.52 \text{ MM}$$

With an interest rate of approximately 3.4%, this leads to a first year cost of $10 MM. WSPA believes that ARB has developed this estimate based on the “Purchase Option” where

operators can purchase and retrofit the existing 20 portable tanks with control devices ($500,000/tank x 20 tanks = $ 10 MM).

There are several issues with this cost-effectiveness analysis using the "Purchase Option":

(i) ARB has made an incorrect assumption that in order to comply with this regulation, operators would simply need to purchase and retrofit the 20 portable tanks with control devices that provide 95% efficiency. As seen above, there is ***no current technology*** proven to capture and control 95% of the emissions, especially for sources with low gas volumes/emissions expected to be resultant from low GOR wells typical in CA. More information on assessment of existing and proposed capture and control technologies is provided under the Control Technologies section.

(ii) The "Purchase Option" will need more than 20 tanks state-wide. Currently, 20 portable tanks are rented from well service companies and "shared" by several operators to minimize operational costs. If companies were to purchase these tanks, the "sharing" of tanks between operators would not be possible. As a result, more than 20 tanks would be required for operators state-wide. WSPA estimates that at least 30 tanks would be needed with the purchase option. Assuming similar retrofit costs as ARB, the costs associated with 30 tanks is $15 MM ($500,000/tank x 30 tanks = $15 MM). Note that vendor quotes for purchasing a retrofitted tank is $285,000. This does not include additional disposal costs such as the cost of renting a portable flare.

(iii) ARB has not included costs associated with training employees/contractors to set up and use the purchased and retrofitted equipment. Well servicing companies provide trained personnel with the current rented tanks who set up the equipment and carry out the wellbore sand cleanup process. Currently, the cost of renting the tanks and acquiring the needed services is approximately $84,000 per year. If the operators cannot rent equipment, additional costs of employing or acquiring trained personnel (trained to set up retrofitted equipment) will be incurred. WSPA estimates that a minimum of 5 additional FTEs will be needed which is an additional cost of $660,000 per year ($66/hr/FTE x 2000 hrs/yr x 5 FTE = $660,000/yr).

(iv) Assuming that the technology is feasible, WSPA estimates the first year cost to be $15.66 MM ($15 MM for equipment + $660,000 for services = $15.66 MM). Assuming 3.4% interest rates, the total 20 year cost of the purchase option is $42.5 MM (compared to $19.52 MM provided by ARB).

(v) The average cost per year is $2.124 MM ($42.5 MM ÷ 20 years = $2.124 MM)

(vi) Utilizing ARB's emission estimates, the state-wide cost to benefit ratio of the "Purchase Option" is $87/MT CO_2e ($2.124 MM/24,400 MT CO_2e = $87/MT CO_2e)

(vii) WSPA's emissions estimates gives state-wide cost to benefit ratio of $265.5/MT CO_2e ($2.124 MM/8,000 MT CO_2e = $265.5/MT CO_2e).

A second option (Rent Option) that operators may have is renting tanks that are retrofitted with appropriate controls assuming that they can provide the required capture and controls proposed in the regulation.

The cost effectiveness analysis for the "Rent Option" is provided below:

(i) Vendor quote for renting a retrofitted tank is $1,750 per day. The cost of renting a flare can range from $800-$1,000 per day.

(ii) The total cost of renting the equipment is estimated to be $6,000 per event ($3,000 per day x 2 days per average event = $6,000 per event). The annual cost of rentals is $4.8 MM.

(iii) The total 20-year cost with the "Rent Option" is $96 MM ($4.8 MM per year x 20 years = $96 MM).

(iv) Utilizing ARB's emission estimates, the state-wide cost to benefit ratio of the "Rent option" is $197/MT CO_2e ($4.8 MM/24,400 MT CO_2e = $197/MT CO_2e)

(v) WSPA's emissions estimates gives state-wide cost to benefit ratio of $600/MT CO_2e ($4.8 MM/8,000 MT CO_2e = $600/MT CO_2e).

In addition to state-wide emissions, ARB also needs to assess operator or event level cost impacts. For an average event, the cost effectiveness of the purchase option can cost an operator approximately $2,655/MT$CO_2e$ and the rental option can cost approximately $6,000/MT CO_2e. The cost to benefit ratio will increase significantly if the events lead to even fewer emissions.

Definitions

The current proposed regulation is unclear in describing the applicability of requirements. Several operators raised concerns during the workshops asking for clarity in requirements compared to other existing regulations. In order to clarify applicability of the requirements, alignment and consistency with the definitions with existing regulations provided in Senate Bill 4 (SB4) and Division of Oil, Gas and Geothermal Resources (DOGGR) is essential for the following items:

- *"Well stimulation treatment"*
- *"Acid well stimulation treatment"*
- *"Hydraulic fracturing"*
- *"Field"*

Recommendations for suggested definitions are provided below.

Recommendations

Cost Effectiveness: WSPA recommends that ARB conduct cost-feasibility analysis at the event level and include applicability thresholds within the regulation at which point the capture and control of emissions from circulation tanks is technologically feasible and cost-effective. At a cost to benefit ratio of $10/MT CO_2e per event, the thresholds for the purchase option and rental option lead to 10 MT CH_4 ($2,655 ÷ [$10 x 25]) and 24 MT CH_4 ($6,000 ÷ [$10 x 25]) respectively. WSPA believes that 10 MT CH_4 as the applicability threshold would be cost-effective for circulation tanks if the control technologies are achievable.

Alternative Methods of Control: As the current proposed regulation has not considered the possibility of not being able to implement the options of control listed in Section 95213(c), WSPA suggests that ARB consider adding to the regulatory language an alternative method of controlling emissions for events that are below 10 MT CH_4 and those events where none of the proposed control technologies would be feasible. WSPA is suggesting the development and implementation of a Best Practices Management Plan (BMP) as an alternative method of control. Some of the best practices that can be implemented including but not limited to:

- Use of tanks instead of open shaker pits
- Optimization of recirculation rates to balance duration
- Reduced duration of recirculation per event to minimum practicable
- Influx Control Plan
- Visual inspection of recirculation fluid
- Monitor the recirculation tank level for influx
- Influx Response Plan

WSPA recommends that ARB allow operators to develop and implement a BMP and to demonstrate how the emissions are minimized for each event.

Regulatory Language Changes: Incorporating the comments above, WSPA suggests the following changes to the proposed regulation (including the addition of new definitions):

Section 95212

(52) "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the underground crude oil or natural gas reservoir. ~~Examples include hydraulic fracturing, acid fracturing, and acid matrix stimulation.~~ Well stimulation treatments include, but are not limited to, hydraulic fracturing treatments and acid well stimulation treatments. Well stimulation treatments do not include steam flooding, water flooding, or cyclic steaming and do not include routine well cleanout work, routine well maintenance, routine removal of formation damage due to drilling, bottom hole pressure surveys, or routine activities that do not affect the integrity of the well or the formation.

"Acid well stimulation treatment" means a well stimulation treatment that uses, in whole or in part, the application of one or more acids to the well or underground geologic formation. The acid well stimulation treatment may be at any applied pressure and may be used in combination with hydraulic fracturing treatments or other well stimulation treatments. Acid well stimulation treatments include acid matrix stimulation treatments and acid fracturing treatments. Acid matrix stimulation treatments are acid treatments conducted at pressures lower than the applied pressure necessary to fracture the underground geologic formation.

"Hydraulic fracturing" means a well stimulation treatment that, in whole or in part, includes the pressurized injection of hydraulic fracturing fluid or fluids into an underground geologic formation in order to fracture or with the intent to fracture the formation, thereby causing or enhancing the production of oil or gas from a well.

"Field" has the same meaning as a field defined by Division of Oil, Gas & Geothermal Resources using Field Rules.

Section 95213

(b) Circulation Tanks for Well Stimulation Treatments

(1) Beginning 1/1/2018, circulation tanks used in conjunction with well stimulation treatments shall meet the following requirements, if the estimated emissions per circulation event (including all stages) determined according to 95213(b)(3) exceed 10 MT CH_4:

(A) Control emission vapors from liquids prior to the circulation tank using a vapor collection and control system as described in section 95213(c); or,

(B) Circulation tanks shall be equipped with leak free solid roofs and hatches; and,

(C) Circulation tanks shall be controlled with use of a vapor collection system and control system as described in section 95213(c).

(2) If the estimated emissions per circulation event (including all stages) determined according to 95213(b)(3) are less than or equal to 10 MT CH_4, the operator shall meet one of the following requirements beginning 1/1/2018:

(A) Control emissions as described in 95213(b)(1); or

(B) Develop and implement a Best Practices Management Plan (BMP) to minimize emissions from circulation tanks used in well stimulation treatments. The BMP must include:

(i) A description of the operator processes and procedures associated with well stimulation treatments.
(ii) List of all contractors and company personnel conducting the well stimulation treatments.
(iii) Description of all methods utilized in minimizing emissions from the well stimulation treatments.

(3) Operators must determine the estimated emissions per event as described below:

(A) Determine annual average field gas to circulation water ratio and annual average field CH_4 Mole% of flash gas for a field according to one of the following methods –

(i) Beginning 1/1/2017, annually conduct a flash liberation test at the inlet of the circulation tank or an ARB-approved test/measurement for each stage during each event for at least 3 representative wells from the same field; or
(ii) Assume the annual field average gas to circulation water ratio is equal to produced gas to oil ratio of the field and annual field average CH_4 Mole% of flash gas is equal to CH_4 Mole% of field produced gas as determined from representative tests.

(B) Determine the estimated emissions for each circulation event as follows:

$$E = \sum_{1}^{n} \frac{GCR_n \times R_n \times t_n \times CH4\ Mole\%_n \times 0.0192}{1{,}000}$$

Where,

E	=	*Estimated emissions in MT CH_4 for a circulation event*
n	=	*Number of stages in a circulation event*
GCR_n	=	*Annual average field gas to circulation water ratio in scf/bbl during each stage determined using one of the methods in 95213(b)(3)(A)*
R_n	=	*Water/Fluid circulation rate in bbl/min during each stage of the circulation event*
t_n	=	*Duration in min of each stage of the circulation event*
CH_4 Mole%$_n$	=	*Annual average field CH_4 Mole% of flash gas*
0.0192	=	*Density of Methane in scf/kg*
1000	=	*Conversion unit from kg to MT*

(C) Vapor Collection Systems

The following requirements apply to primary and secondary vessels and to circulation tanks for well stimulation treatments subject to the requirements of 95213(b)(1):

(1) The vapor collection system shall direct the collected vapors to one of the following types of existing equipment or processes installed at the operation:

(A) Sales gas system; or,

(B) Fuel gas system; or,

(C) Underground injection well.

(2) If the owner or operator can demonstrate to the satisfaction of the local air district that the collected vapors cannot be controlled according to one of the methods described in section 95213(c)(1), the vapor collection system shall direct the collected vapors to an existing vapor control device provided that any added vapors do not exceed the device's permitted emission limits.

(3) The owner or operator must demonstrate to the satisfaction of the local air district that the collected vapors cannot be controlled according to one of the methods described in section 95213(c)(1) or 95213(c)(2) if they wish to use any of the methods described in section 95213(c)(4).

(4) If the owner or operator can successfully demonstrate that the collected vapors cannot be controlled according to one of the methods described in 95213(c)(1) or 95213(c)(2), the owner or operator must apply for local air district approval to install one of the following:

(A) A vapor control device with at least 95% vapor control efficiency and which meets all applicable federal, state, and local air district requirements; or,

(B) If the system is located in an area classified as nonattainment with state or federal ozone standards, the owner or operator must apply for local air district approval to install one of the following types of equipment that meets all applicable federal, state, and local air district requirements:

1. A non-destructive vapor control device that achieves at least 95% vapor control efficiency and does not result in emissions of nitrogen oxides (NOx) above local air district requirements; or,

2. A vapor control device that that achieves at least 95% vapor control efficiency and does not require supplemental fuel gas to operate or result in emissions of NOx above local air district requirements.

(5) If an owner or operator can successfully demonstrate to the satisfaction of the local air district that the circulation tanks cannot be controlled according to any of the methods described in sections 95213(c)(1)-(4), the owner or operator must comply with the requirements of 95213(b)(2)(B).

(6) ~~(5)~~ Vapor collection systems are allowed up to 14 calendar days per year for equipment breakdowns or maintenance provided that the local air district is notified within one (1) hour of the discovery of a system malfunction or if the system is intended to be taken out of service for scheduled maintenance. A time extension to make repairs not to exceed 14 calendar days may be granted by the local air district. The owner or operator is responsible for tracking the number of days per calendar year that the system is out of service and must provide a record of such activity at the request of the local air district.

(7) ~~(6)~~ Vapor collection system shutdowns that result from utility power outages or emergencies are not subject to enforcement action provided the system resumes normal operation as soon as normal utility power is restored.

WSPA Comments
Primary and Secondary Vessel
Onshore and Offshore Crude Oil and Natural Gas Production Sector

Issues

Emissions

Table 1 of ARB's Standardized Regulatory Impact Assessment (SRIA) dated 4-29-15 states that the emissions from the additional leaks covered by the proposed regulation will lead to a reduction of approximately 252,000 MT CO_2e (or 10,080 MT CH_4):

Table 1: Summary of Annual Emissions and Reductions for O&G Proposal (2018 and forward)[5]

Proposed Category For Control	Emissions before Regulation (tonnes CO_2e)	Reductions from Proposal (tonnes CO_2e)
Uncontrolled Oil and Water Separators and Tanks	265,000	252,000
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Liquids Unloading	400	350
Components under New LDAR Program	2,900	1,200
Remaining Venting and Fugitive Emissions for Proposed Regulated Categories (includes equipment controlled under existing district programs, such as already-controlled tanks and components)	41,000	0
TOTAL	**998,000**	**556,000**
All Other Oil & Gas Venting and Fugitive Sources (e.g., compressor blowdowns, dehydrators, etc.)	341,000	0
GRAND TOTAL	**1,339,000**	**556,000**

WSPA agrees with the emissions estimates provided as they are similar to emissions reported under GHG Mandatory Reporting Rule. However, WSPA is concerned about the scope of the proposed regulation. Our understanding is that ARB is targeting 94% of the state-wide uncontrolled emissions. This includes tank systems that have very low emissions (10 MT CH_4) annually. Thus, the low threshold of applicability and high cost-to-benefit ratio will be extremely burdensome for operators.

Applicability Thresholds and Cost Effectiveness

ARB has proposed 10 MT CH_4 as the applicability threshold for this source category. Although the SRIA states \$40/MT CO_2e as the state-wide cost-effectiveness, ARB has not provided operator-level cost-effectiveness. The operator-level analysis unmasks some of the burdens that a typical operator would face.

The cost of installing and maintaining a vapor recovery system (VRS) can range from \$0.5 MM - \$2.5 MM per tank system. The cost to benefit analysis at various thresholds for one tank system is provided in the table below.

Table 1. Operator cost to benefit ratio (\$/MT CO2e) of installing a vapor recovery system on a tank system at different applicability thresholds estimated over a 20 year period.

PARAMETERS	>10 CH4 MT	>100 CH4 MT	>250 CH4 MT	>500 CH4 MT	>1000 CH4 MT
20 YR COST	\$ 975,996	\$ 1,951,992	\$ 2,927,988	\$ 3,903,983	\$ 4,879,979
20 YR EMISSIONS (MT CO2E)	5,000	50,000	125,000	250,000	500,000
COST/BENEFIT (\$/MT CO2E)	\$ 195	\$ 39	\$ 23	\$ 16	\$ 10

The costs incurred by an operator at a very low threshold of 10 MT CH_4 are extremely burdensome and unreasonable. For example, if an operator has to install a VRS on a tank system with annual emissions of 10 MT CH_4, the cost to benefit ratio over a 20-year period is approximately \$195/MT CO_2e. This represents at least 16 times the current market value of CO_2e.

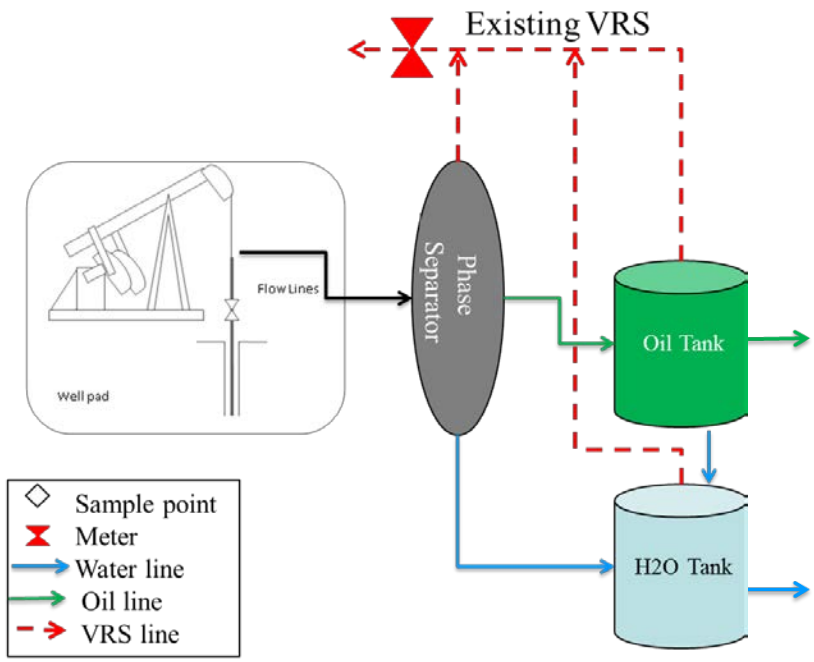
WSPA requests that in determining the threshold for this source category, ARB consider the costs that an operator would incur at each tank system. WSPA believes that the threshold should be set as close to current market value of CO_2e as possible. As such, WSPA requests ARB consider 250 MT CH_4 as the threshold for applicability for installing a vapor recovery system. At this threshold, approximately 72% of the state-wide emissions can be reduced with a cost to benefit of \$23/MT CO_2e as seen in Table 1 above.

Scope

As currently written, the proposed regulation is unclear with regards to which tanks/vessels are subject to the requirements. WSPA's understanding of ARB's intent is to implement the following with the proposed regulation:

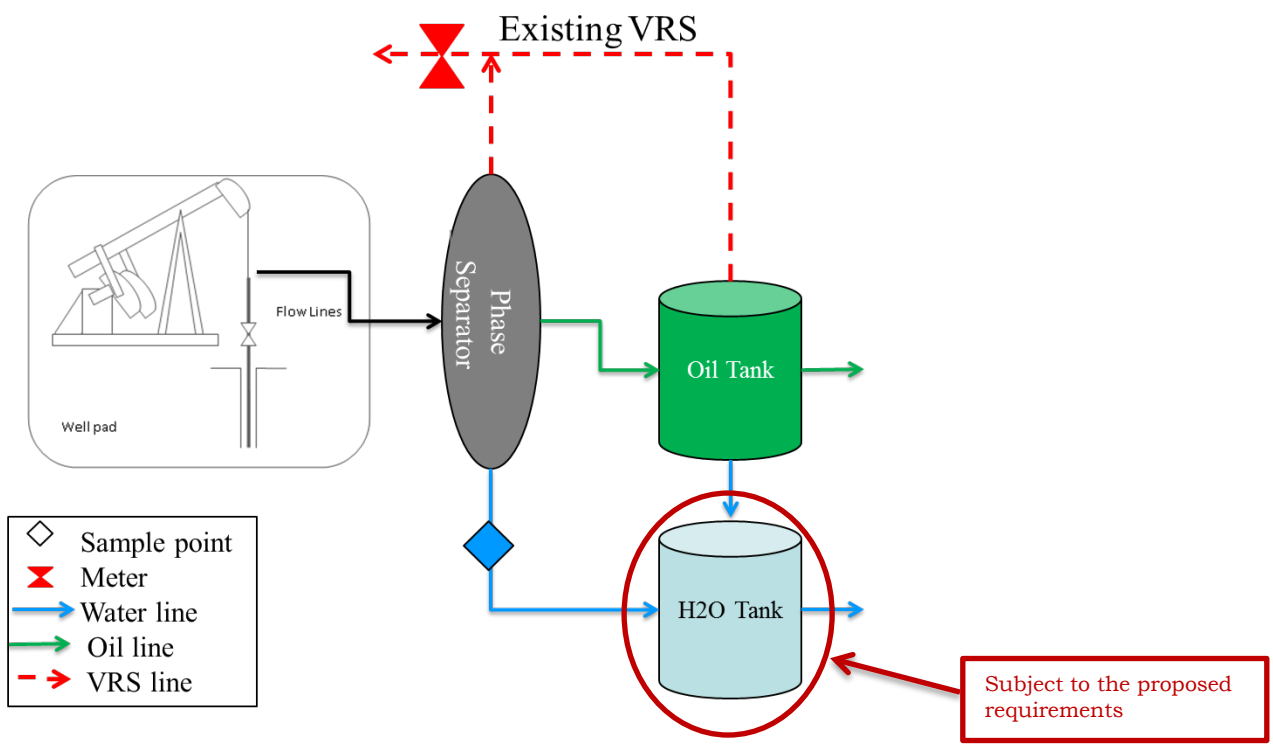
WSPA understands that Example 1 configuration would not be subject to any of the proposed requirements in the regulation since the first vessel (Phase Separator) and the second vessels (Oil and Water tanks) following a well on the crude oil and produced water lines are already under vapor recovery.

Example 1



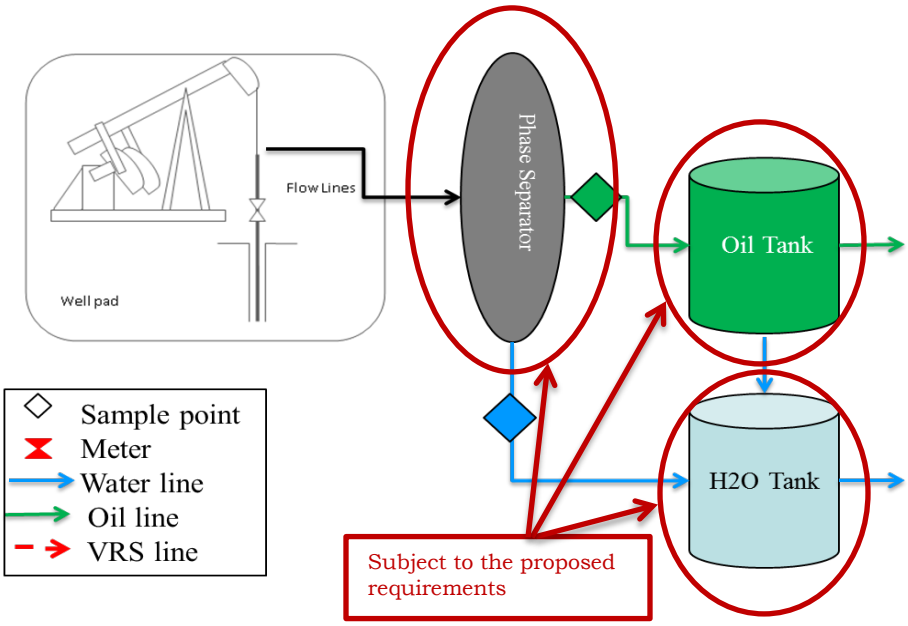
WSPA understands that in the Example 2 configuration shown below, only the identified produced water tank would be subject to the proposed requirements of the regulation.

Example 2



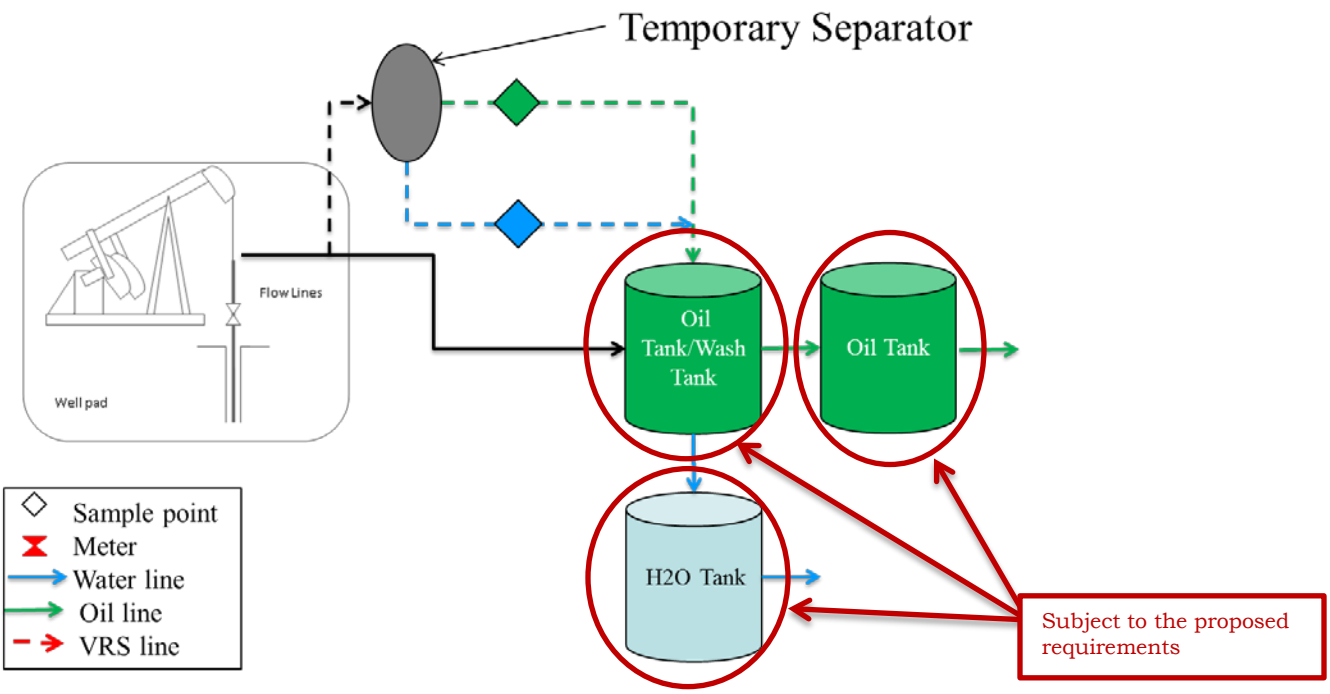
WSPA understands that in the Example 3 configuration shown below, the identified phase separator, oil tank, and produced water tank would be subject to the proposed requirements of the regulation.

Example 3



WSPA understands that in the Example 4 configuration shown below, the identified oil tanks and produced water tanks would be subject to the proposed requirements of the regulation.

Example 4



WSPA requests that ARB clarify the scope of the regulation as suggested below in the Recommendation section. If ARB's intent is different from WSPA's understanding, WSPA would like ARB to provide further clarifications.

Definitions

The current proposed regulation is unclear in describing the applicability of requirements. Several Operators raised concerns during the workshops asking for clarity in requirements compared to other existing regulations. In order to clarify applicability of the requirements of the proposed regulation, WSPA requests that ARB edit/add the following definitions.

"Flashing"

Although the term "Flash" is used in the regulation, the definition is confusing and may lead to incorrect interpretation as written:

> *(14) "Flash" means emissions that vaporize from crude oil, condensate, or produced water when the liquids are subject to a decrease in pressure, such as when liquids are transferred from an underground reservoir to the earth's surface.*

The flashing process does not involve "vaporizing" which occurs at the boiling point of a liquid or sublimation point of a solid. Instead, flashing is the release of entrained gas from a high pressure liquid when there is a pressure decrease. The California Greenhouse Gas Mandatory Reporting Regulation (GHG MRR) has a definition for "flashing" (see below) that is more representative of the actual process of gas release during flashing. However, this process is not a phase change as described. Phase changes happen only at boiling or melting/freezing points of a liquid or solid.

> *"Flashing," for purposes of Appendix B, means the release of hydrocarbons and carbon dioxide from liquid to surrounding air when the liquid changes temperature and pressure, also known as phase change.*

There are other existing definitions of flashing that are more comprehensive and provide an accurate description of the actual process. American Petroleum Institute's (API's) 2009 GHG Compendium provides the following explanation of flashing emissions.

5.4 Storage Tank Emissions

5.4.1 Crude Flashing Losses

Where liquids are in contact with a gas phase, high pressures will cause some of the gas to go into solution (i.e., thermodynamic equilibrium between the phases will eventually occur). When the liquid is brought to atmospheric conditions, the solution gas is released through a rapid process called flashing.

Crude oil production tanks (primarily fixed roof tanks) emit CH_4 (and potentially CO_2 for a CO_2 - rich stream) through flashing losses, which occur as the crude oil pressure decreases from the separator conditions to atmospheric pressure in the storage tank. Flashing emissions can be significant where there is a significant reduction in pressure. This primarily occurs in production operations; however, flashing emissions can also occur from oil pipeline pigging. Once crude oil reaches atmospheric pressure and the volatile CH_4 has flashed off, the crude is considered "weathered" or stabilized. Unless site-specific data indicate otherwise, "weathered" crude is assumed to have no CH_4.[3]

WSPA requests that ARB modify the definition of flashing to accurately represent the process. WSPA's suggested definition based on API Compendium is provided below in the Recommendation section.

"Flash Analysis Testing"

The current proposed definition is as follows:

> *(15) "Flash analysis testing" means sampling and laboratory procedures used for measuring the volume and composition of gas compressed into liquids, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a gas-oil or gas-water ratio.*

The term "compressed into liquids" is confusing and implies that gas was compressed into a liquid prior to conducting flash liberation test. Gas compression into liquid is a cryogenic process – where enough pressure is applied to a gas (which is in gaseous phase at room temperature) such that the gas undergoes a phase change into liquid at extremely low temperatures. For example, gases like nitrogen or oxygen are compressed into liquid nitrogen or liquid oxygen. This process is not the same as flash analysis testing.

A more accurate description is included in the GHG MRR that has the following definition -

> *"Flash Analysis," for purposes of Appendix B, means laboratory methodologies for measuring the volume and composition of gases released from liquids, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a Gas-Oil Ratio or Gas-Water Ratio required to calculate the specified emission rates as described in Section 10 of Appendix B.*

WSPA requests that ARB align the definition for "flash analysis testing" with the existing more accurate definition of the term from GHG MRR.

"Primary vessel" and "Secondary vessel"

As currently defined, the two terms "primary vessel" and "secondary vessel" are unclear and subject to multiple interpretations. WSPA understands that ARB is trying to define the terms in such a way that they can be applied to the greatest possible variety of tank system configurations. The proposed definitions are below:

> *(33) "Primary vessel" means the first vessel that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more crude oil or natural gas well and allows emissions to flash from the liquids to a headspace or to the atmosphere.*
>
> *(42) "Secondary vessel" means any vessel that receives crude oil, condensate, produced water, natural gas, or emulsion from a primary vessel and allows emissions to flash from the liquids to a headspace or to the atmosphere. There may be more than one secondary vessel in a separation and tank system.*

WSPA requests that ARB clarify the definitions as suggested below in the Recommendation section. WSPA also requests that ARB provide clarifications for different configurations of tank systems to ensure Operators are clear on the applicability and requirements of the proposed regulation.

"Tank System"

Currently, ARB does not define the term tank system although the term is used in the proposed regulation. WSPA understands that ARB has assessed applicability, emissions, and costs at each tank system level. WSPA believes that this term is very critical in defining boundaries, clarifying the requirements of the proposed regulation and appropriately assessing emissions and costs. In addition, this term will be crucial during the permitting process and will allow local air districts to clearly identify the tanks in case of complex tank system configurations.

Recommendations

Incorporating the comments above, WSPA suggests the following changes to the proposed regulation:

Section 95212

(14) "Flashing" means a rapid process during which gas entrained in a solution at high pressure is released when there is a decrease in pressure. Flashing occurs when produced liquid (crude oil or condensate or produced water) is exposed to pressure decreases during the transfer from the production separators (or similar sources) into atmospheric storage tanks. ~~emissions that vaporize from crude oil, condensate, or produced water when the liquids are subject to a decrease in pressure, such as when liquids are transferred from an underground reservoir to the earth's surface.~~

(15) "Flash analysis testing" means sampling and laboratory procedures used for measuring the volume and composition of gas released from liquids ~~compressed into liquids~~, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a gas-oil or gas-water ratio.

(33) "Primary vessel" means the first vessel that is immediately downstream of one or more crude oil or natural gas wells and receives crude oil, condensate, produced water, natural gas, or emulsion directly from one or more crude oil or natural gas wells. Primary vessels do not include vessels that are solely used for well testing purposes. ~~and allows emissions to flash from the liquids to a headspace or to the atmosphere.~~

(42) "Secondary vessel" means ~~any~~ one or more second vessels that are downstream and in series with a primary vessel and receive crude oil, condensate, produced water, natural gas, or emulsion directly from a primary vessel. Secondary vessels do not include vessels that are solely used for well testing purposes. ~~and allows emissions to flash from the liquids to a headspace or to the atmosphere. There may be more than one secondary vessel in a separation and tank system.~~

"Tank System" means a crude oil or condensate or produced water system containing vessels in series and/or in parallel operation.

Section 95213

(a) Primary and Secondary Vessels located in the Onshore and Offshore Crude Oil and Natural Gas Production Sector

(1) Tank systems with a vapor collection system already installed on the primary and secondary vessels are not subject to the requirements of this section.

(2) ~~Owners or operators of crude oil, condensate, or produced water vessels~~ The requirements of this section apply to tank systems without a vapor collection system installed on the primary and secondary vessels. The owners or operators of such tank systems shall install a vapor collection system on the primary and/or secondary vessels that do not currently have the vapor recovery system and that are not pressurized vessels, as described in section 95213(c) or perform the following:

(A) Where technically feasible, c~~C~~onduct annual flash analysis testing of the crude oil, condensate, and produced water separated or stored by the primary and secondary vessels to determine the annual methane emission rate for each tank system as follows:

1. Flash analysis testing shall be conducted in accordance with ARB Test Procedure Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water as described in Appendix A.

2. Flash analysis testing is required at each primary vessel. Additional flash analysis testing may be conducted and the results averaged in order to determine representative testing.

3. Sum the annual emission rates of methane as determined in section 95213(a)(2)(A)(2)~~(1)(B)1~~ for the crude oil, condensate, and produced water.

4. Report the results of flash analysis testing as described in section 95215(a)(1).

5. Owners or operators must demonstrate that the results of the flash analysis testing are representative of the liquids processed by the primary and secondary vessels. The ARB or the local air district may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems.

(B) For tank systems where flash liberation testing is technically infeasible, the operator may use representative test results from the crude oil, condensate, and produced water separated or stored by the primary and secondary vessels located within the same field. If flash liberation testing is infeasible for all wells in a field, the operator may use the production gas to oil ratio of the field using the most current annual production data.

(C) Owners or operators of primary and secondary vessels with a measured annual emission rate for each tank system greater than 250~~10~~ metric tons per year of methane as determined in section 95213(a)(2)(A)(3)~~1)(B)(3)~~ shall control the primary and secondary vessels as follows:

a. Vessels shall be equipped with leak free solid roofs and hatches; and,

b. Vessels shall be controlled with use of a vapor collection system as described in section 95213(c).

(C) Owners or operators of primary and secondary vessels without a vapor collection system and a measured annual emission rate less than or equal to ~~10~~ 250 metric tons per year of methane as determined in section 95213(a)(2)(A)(3)~~1)(B)(3)~~ shall conduct flash analysis testing and reporting annually, unless the owner or operator can demonstrate that the annual emission rate has not changed using three (3) consecutive years of test results; and,

~~1.~~ If the owner or operator can successfully demonstrate to ARB or the local air district that the results of flash analysis testing have not changed by more than ten (10) percent using three consecutive years of test data, flash analysis testing and reporting may be reduced to once every five (5) years thereafter.~~; and,~~

2. ~~Flash analysis testing and reporting shall be conducted at any time the annual crude oil or natural gas throughput of the primary and secondary vessels increases by more than ten (10) percent since the most recent flash analysis testing and reporting.~~