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California Air Resources Board
1001 I Street – P.O. Box 2815
Sacramento, CA 95812

Re: SoCalGas and SDG&E Comments on Revised Draft Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

Dear Mr. Fischer:

On behalf of the Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E), the following comments are respectfully submitted in response to the California Air Resources Board (ARB) Public Workshop on February 4, 2016. Our comments on the proposed regulation are organized as follows:

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I. GLOBAL WARMING POTENTIAL SHOULD BE BASED ON A 100-YEAR TIME HORIZON

For consistency with U.S. and international reporting convention, ARB should use global warming potential (GWP) values based on a 100-year time horizon published in the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report. California and Federal regulatory programs currently use, and consistently have used, the 100-year GWP values for greenhouse gases (GHG). Indeed, ARB's own Regulation for the Mandatory Reporting of Greenhouse Gas Emissions[1] (MRR) requires that covered entities report emissions in metric tonnes of carbon dioxide equivalent ($MTCO_2e$) using the GWP contained in the U.S. Environmental Protection Agency's (EPA) mandatory greenhouse gas reporting regulation in 40 CFR § 98 (GHGRP): "For the purposes of this article, global warming potential values listed in Table A-1 of 40 CFR Part 98 are used to determine the CO2 equivalent of emissions."[2] Table A-1 lists the GWP of methane (CH_4) using a 100-year time horizon. In addition, the GWP used in ARB's own Cap-and-Trade Program[3] is determined by reference to the GWP used in the MRR and, therefore, similarly uses a 100-year GWP value.[4] It is no accident that all three of these regulatory regimes use 100-year GWP values as the California regulations were purposely promulgated to be consistent with one another and the EPA GHGRP.[5]

Moreover, the Low Carbon Fuel Standard (LCFS) likewise utilizes the 100-year GWP value for CH_4. For example, when assessing the carbon intensity of certain alternative fuels (which are measured in grams of CO_2e per megajoule), ARB grants credit for avoided CH_4 emissions using the 100-year GWP value.[6] ARB also uses the 100-year GWP value in its GHG emission inventory program, which tracks statewide GHG emissions levels.[7]

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[1] 17 Cal. Code Regs. § 95100 et seq. (MRR).

[2] 17 Cal Code Regs. § 95102(66).

[3] 17 Cal. Code Regs. § 95800 et seq.

[4] 17 Cal. Code Regs § 95802(56).

[5] *See generally* ARB, Final Statement of Reasons for Rulemaking at 5 (Nov. 2, 2012), available at http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012finalfsor.pdf ("The proposed revisions to the regulations are necessary to support California's cap-and-trade program, as well as further harmonization with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory greenhouse gas (GHG) reporting requirements").

[6] *See* 17 Cal. Code Regs § 95488 (c)(3),(4) (requiring use of CA-GREET 2.0 models in determining carbon intensities); ARB, CA-GREET Tier 1 model, available at http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm (using 100-year GWP in "Fuel Specs" tab); *see also* 17 Cal. Code Regs § 95852.1.1(b) ("In the case of biomethane or biogas . . . the resulting credit for avoided methane emissions may not exceed the global warming potential as listed in MRR for methane plus 2.75 in metric tons of CO_2e per ton of captured methane. This includes any credit received by an entity in the Carbon Intensity calculation under the Low Carbon Fuel Standard Regulation . . . for methane capture. All calculations of CO2e emissions

Use of a 20-year time horizon for GWP values would muddle an otherwise consistent regulatory framework, complicate the assessment of California's progress in GHG emissions reductions, upset the settled expectations of stakeholders, and disrupt carbon credit markets. Here, the use of a 20-year GWP value for CH_4 of 72 in ARB Staff's presentation at the February 4, 2016 public workshop results in misleading and biased cost estimates for reductions in GHGs. If the 100-year GWP for CH_4 used in the MRR and Cap-and-Trade Program of 21 were used, then ARB's estimates of the costs of reductions in CO_2e emissions would have been approximately 3.4 times higher. For example, rather than the alleged $40 per $MTCO_2e$, the cost of emission reductions due to Leak Detection and Repair (LDAR) would be approximately $136 per $MTCO_2e$. This cost far exceeds the marginal abatement cost of other methods of reducing CH_4 emissions and also exceeds current prices for Cap-and-Trade Program compliance instruments. For all of these reasons, we urge ARB to utilize a 100-year GWP value for CH_4 in this rulemaking, consistent not only with other agencies, but also with ARB's own existing rules.

II. THE PREMATURE ADOPTION OF REGULATIONS COULD CREATE AN UNWORKABLE PATCHWORK

ARB is one of many agencies proposing new regulations for GHG emissions from the oil and gas sector in 2016. Having so many actors proposing separate—and sometimes conflicting—rules has the potential to create a dizzying patchwork of regulations that would generate confusion and increase cost to industry beyond the commensurate benefits in GHG and criteria pollutant emissions reductions. Accordingly, ARB should refrain from formally proposing or adopting regulations regarding leak detection and repair and other GHG controls until it can ensure that those regulations will not result in regulatory conflict or overlap.

In addition, as noted in our previous letters, as a regulated utility, SoCalGas cannot undertake infrastructure repair projects as quickly as ARB contemplates. Instead, SoCalGas requires approval from the California Public Utilities Commission (CPUC) before it may proceed with certain projects (e.g., those constituting capital improvements). Therefore, any regulations ultimately proposed should recognize and account for these and other practical considerations facing regulated utilities, including SoCalGas and SDG&E. The most streamlined and effective way to address this issue would be to exempt Essential Public Services from this rulemaking – as addressed in our prior comment letter dated May 15, 2015. Should ARB deem such an exemption to be unsuitable, greater flexibility with regard to the prescriptive leak repair time periods is strongly suggested.

A. Pending Agency Rulemakings and Proceedings Have the Potential to Substantively Overlap with ARB's Discussion Draft Regulations

Currently, at least five other agencies have proposed rulemakings, promulgated regulations, or issued advisory opinions regarding GHG emissions from the oil and gas sector. If

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are based on the 100-year global warming potentials included in MRR."). Thus, a GWP for methane of 21 is used for this analysis.

[7] ARB, Global Warming Potentials (May 6, 2015), available at http://www.arb.ca.gov/cc/inventory/background/gwp.htm ("All GWPs used for GHG inventory purposes are considered over a 100-yr timeframe.").

each agency were to adopt such rules, remaining in compliance would become exceptionally difficult for regulated parties. Operations personnel at affected facilities would have to reconcile their monitoring and reporting activities with every aspect of each regulation's many requirements, which at this point appear unlikely to be wholly consistent with one another. SoCalGas acknowledges and sincerely appreciates that ARB has been coordinating and/or consulting with other agencies during the preparation of their respective regulations, and urges that ARB continue to work with other agencies with the goal of synching regulatory requirements to the greatest extent feasible. As it stands now, however, each agency is poised to either implement or phase in its regulations at different times. These substantive and temporal inconsistencies create inefficiencies by requiring affected facility operators to continuously update their practices and compliance procedures.

The current agency actions include:

- **U.S. Environmental Protection Agency Greenhouse Gas Reporting Program.** On January 29, 2016, EPA proposed revisions and additional confidentiality determinations for the petroleum and natural gas systems source category of the GHGRP.[8] In particular, EPA is proposing to add new monitoring methods for detecting leaks from oil and gas equipment for petroleum and natural gas systems in line with recently proposed new source performance standards for the oil and gas industry. The proposed rule is aimed at allowing facilities to consistently demonstrate compliance with multiple EPA programs. EPA also is proposing to add emission factors for leaking equipment to be used in conjunction with these monitoring methods to calculate and report GHG emissions resulting from equipment leaks. Further, EPA is proposing reporting requirements and confidentiality determinations for nine new or substantively revised data elements. These reporting requirements will be directed at facilities conducting equipment leak surveys. The facilities will begin reporting emissions using a specific leak survey methodology, and will additionally report the number of leaking components, and the average time the components were assumed to be leaking.

- **U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Advisory Bulletin.** On February 5, 2016, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") published an advisory bulletin directing all owners and operators of natural gas underground storage facilities to check for leaks in wellheads and pipelines, verify that shutoff valves and other safety equipment are in working order, and verify that the pressure used to force gas underground does not exceed

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[8] *See* 81 Fed. Reg. 4987-5006 (Jan. 29, 2016), available at https://www.gpo.gov/fdsys/pkg/FR-2016-01-29/pdf/2016-01669.pdf.

the design limits of the underground reservoir or the associated equipment.[9] The bulletin also directs operators to update their emergency plans.

- **Senate Bill 1371.** In January 2015, the CPUC adopted an order instituting rulemaking ("OIR") to reduce natural gas leakage consistent with Senate Bill ("SB") 1371.[10] SB 1371 requires the adoption of rules and procedures, in consultation with ARB, to minimize natural gas leakage from CPUC-regulated natural gas pipeline facilities. SB 1371 also requires gas corporations to file an annual report to the CPUC and ARB about their natural gas leaks and their leak management practices.[11]

  Specifically, in implementing SB 1371, the CPUC must: (1) provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components; (2) provide for the repair of leaks as soon as reasonably possible after discovery; (3) evaluate the operations, maintenance, and repair practices; (4) establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction; (5) establish protocols and procedures for the development and use of metrics to quantify the volume of emissions from leaking gas pipeline facilities, and for evaluating and tracking leaks geographically over time; and (6) to the extent feasible, require the calculation of a baseline systemwide leak rate.[12]

  ARB's discussion draft regulations substantially overlap with the SB 1371 OIR and ARB's consultative role in that proceeding. As stated by SB 1371,[13] the CPUC and ARB should ensure that the regulations and rules adopted by each agency are consistent. To facilitate such consistency and avoid imposing undue burdens on those subject to both sets of regulations, ARB should delay this rulemaking until the CPUC has completed its rulemaking. By refraining from issuing a rule until the CPUC has completed its process with ARB's consultation, ARB would be reducing regulatory conflict.

- **Division of Oil, Gas, and Geothermal Resources Emergency Regulations.** In January 2016, DOGGR issued emergency regulations concerning natural gas storage facilities.[14] These regulations, which became effective on February 5,

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[9] *See* 81 Fed. Reg. 6334-6337 (Feb. 5, 2016), available at http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_C7740235E7B8724D36AA2CF7EBAA18CAFC110300/filename/2016-02228.pdf.

[10] *See* CPUC, Proceeding R-15-01-008, OIR (Jan. 22, 2015).

[11] Cal. Pub. Util. Code § 975.

[12] Cal. Pub. Util. Code § 975(e)(1)-(6).

[13] Cal. Pub. Util. Code § 975(g).

[14] DOGGR's emergency regulations are available at http://www.conservation.ca.gov/index/Documents/Underground%20Gas%20Storage%20Project%20Requirements%2c%20Text%20of%20Proposed%20Regulations.pdf.

2016, require underground gas storage project operators to submit an inspection and leak detection protocol to DOGGR for review and approval by late February 2016. The protocol must include inspection of wellhead assembly and attached pipelines for each of the wells and the surrounding area within a 100 foot radius of the wellhead of each of the wells. The regulations mandate the use of "effective gas leak detection technology," such as infrared imaging, at least once per day. The emergency regulations require the operator to take into consideration certain factors in deciding which leak detection technology to use, such as "detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology."

DOGGR's emergency regulations also require operators of underground gas storage projects to submit a Risk Management Plan to DOGGR for review and approval. These plans must identify potential threats and hazards to reservoir and well integrity, evaluate the risks, identify risk mitigation processes, and establish a process for periodic review of the risk assessment process. Plans must include risk assessment and prevention protocols for: (1) mechanical well integrity; (2) corrosion monitoring and evaluation; (3) monitoring of wells and attendant production facilities for other risks including casing pressure changes, facility flow erosion, hydrate potential, etc.; (4) reservoir integrity demonstration procedures; (5) identification of potential threats and hazards to operation of project; and (6) prioritization of risk mitigation efforts.

In addition, DOGGR requires new monitoring and testing requirements for: annular gas; safety valves; master valves; wellhead pipeline isolation valves; reservoir pressure; and any additional requirements included in the risk management plan adopted.

Notably, DOGGR is required to consult with ARB when reviewing leak detection protocols. Therefore, ARB should consider postponing promulgation of its discussion draft regulations until it has the opportunity to ascertain the effectiveness of DOGGR's emergency regulations and study their implementation. By reviewing the effectiveness and implementation of DOGGR's regulations, ARB may be able to tailor its requirements to avoid conflicting or redundant requirements.

- **Bureau of Land Management/Department of the Interior Proposed Regulations.** The Bureau of Land Management ("BLM") within the U.S. Department of the Interior ("DOI") is proposing new regulations to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases. The proposed rules will require oil and gas producers to adopt currently available technologies, processes and equipment that limits the rate of flaring at oil wells on public and tribal lands, and requires operators to periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. Operators are also required to limit venting from storage tanks and use best practices to limit gas losses when removing liquids from wells.

B. Pending Agency Rulemakings Should Be Coordinated in Advance of Implementation

Each of the above-referenced agency actions has its own unique timing for each phase of approval and implementation. We understand the ARB currently anticipates approving its regulations in September 2016. While the DOGGR emergency regulations were finalized and are being implemented more swiftly, ARB's scheduled finalization date may occur before other agencies are able to finish their rulemaking processes. Additionally, DOGGR has initiated a new rulemaking to "make significant revisions" to its regulations governing natural gas storage and has only just begun to collect input from stakeholders. Accordingly, ARB and the other agencies should consider synchronizing the timing to enact proposed regulations to ensure that the regulations are consistent with one another and do not require duplicative actions.

For example, DOGGR's emergency regulations already require owners and operators to submit a leak detection and inspection protocol to DOGGR for approval later this month. DOGGR's regulations also require owners and operators to monitor for the presence of annular gas daily starting in early March 2016. Owners and operators also must begin "function testing" all surface and subsurface safety valve systems in May 2016, and continue to do so every six months thereafter. Owners and operators also will be required to test the operation of master valve and wellhead pipeline isolation for proper function, and again annually thereafter. Finally, on August 5, 2016, owners and operators must submit a Risk Management Plan to DOGGR. To the extent ARB's regulations ultimately require similar actions at later dates, regulated entities will be forced to conduct duplicative work at a cost that likely exceeds environmental or risk-reduction benefits.

Other pending agency actions may prove instructive and should be fully evaluated by ARB before taking action. For example, EPA published the aforementioned proposed rule to revise the federal GHG reporting rule (40 CFR 98, Subpart W) for consistency with the proposed NSPS (40 CFR 60, Subpart OOOOa) rule in the Federal Register on January 29, 2016. Comments on EPA's proposed rule are due on February 29, 2016. EPA also is conducting an information-gathering phase, and requires industry participants to provide data on hazardous air pollutant emissions from the natural gas production, transmission and storage segments of the oil and natural gas sector by March 11, 2016. This information and submitted comments likely will assist EPA in its rulemaking process. Therefore, it would be prudent for ARB to "wait and see" what EPA's final regulations require before promulgating potentially duplicative or conflicting regulations.

Similarly, the CPUC currently is accepting comments on Phase I issues regarding annual reporting requirements, best management practices, and cost-effectiveness considerations to implement SB 1371. The ARB has been actively involved in the CPUC's SB 1371 OIR, including participation in extensive informal workshops and the CPUC's staff proposal issued on January 26, 2016 regarding reporting requirements reflect ARB's recommendations. The CPUC and ARB are scheduled to hold a workshop on targets, compliance, and enforcement in March 2016. Issuance of an ARB and CPUC staff proposal on targets, compliance, and enforcement is not expected until June 2016, and will be followed by a comment period. This process could offer valuable insight and feedback to both the CPUC and ARB, which should be considered in any proposed rules to avoid unnecessary duplication.

The CPUC is expected to issue a Phase I decision regarding SB 1371's required natural gas leak abatement regulations in the fourth quarter of 2016. Additional rulemaking regarding ratemaking and performance-based financial incentives associated with the natural gas leak abatement program will follow in Phase II, although a specific timeline has not yet been established for that process. Given the potential for ARB's and the CPUC's requirements to overlap, however, SoCalGas suggests that ARB refrain from issuing a rule until the CPUC has completed at least the Phase I process.

Alternatively, ARB's proposed phase-in period could be extended to ensure that its regulations are implemented in way that does not duplicate efforts required by other agencies. For example, BLM/DOI has proposed for its regulations to be phased in over several years to allow operators to make the transition more cost-effectively.

If all of these proposed regulations are implemented at the same time or in rapid succession, it would create a logistical nightmare for affected entities. While the regulations may appear similar, it will take each agency and operator significant time and effort to figure out how each rule actually works in practice, and whether or not these perceived similarities are only superficial. Even if the substantive regulations were to be exactly the same, it is extremely inefficient to require the same information to be reported to different agencies in different formats. Therefore, rather than adding another patch to the current and growing patchwork of regulations governing CH_4 emissions from oil and gas facilities, SoCalGas requests that ARB refrain from pursuing additional regulations at this time and allow the processes of other agencies to more fully run their course.

III. LEAK EMISSION REDUCTION CONCEPT

The current discussion draft of the regulations contains a placeholder providing: "Staff is considering a leak emission reduction requirement for large or catastrophic leaks at any oil and gas facility covered by this regulation." The ARB Staff's presentation at the February 4, 2016 public workshop further provided that potential options include "Specific emission reduction projects" and "Development of an emission reduction plan." We oppose the inclusion of any such emission reduction concept in this regulation.

Rather than require the design of bespoke emission reduction plans or projects for each possible future leak as part of the GHG Emission Standards for Crude Oil and Natural Gas Facilities, SoCalGas urges ARB Staff to utilize, instead, its very own, already existing regulatory structure focused on reducing GHG emissions: the Cap-and-Trade Program. In other words, ARB Staff need not "reinvent the wheel" in these proposed regulations.

If a catastrophic event results in the release of a significant amount of GHG emissions, one way to mitigate these emissions would be through participation in the Cap-and-Trade Program. AB32 compliance instruments (i.e., allowances or offsets) would have already undergone the comprehensive vetting and scrutiny by ARB Staff in accordance with the requirements of the Cap-and-Trade Program. Not only would ARB Staff be conserving valuable and finite agency resources, it also would be achieving real and quantifiable GHG emission reductions at low cost and with a built-in system for the verification of those emissions reductions. As ARB previously has explained: "The regulatory provisions and the requirements of the Compliance Offset Protocols will ensure that the reductions are quantified accurately, represent real GHG emissions reduction, and are not double-counted within the system."[15] Requiring affected facilities (presumably) to fund bespoke emissions reduction plans or projects at a cost likely much higher than comparable compliance instrument prices would be inequitable, and would be unlikely to result in additional environmental benefits. Moreover, the imposition on regulated facilities of such an emissions reduction cost would be duplicative of the cost associated with the penalties provided for in Section 95674 of the discussion draft regulations, which we address in more detail below.

To the extent ARB staff is concerned about potential non-climate forcing impacts of CH_4 emissions, there are existing regulatory structures promulgated under the Federal and State Clean Air Acts that address such issues. We also note that certain compliance instruments used in the Cap-and-Trade Program represent real, permanent, quantifiable, verifiable, enforceable, and additional reductions in emissions of CH_4 (e.g., ARB-approved offset credits from Livestock Projects, Mine Methane Capture, and Rice Cultivation Projects) and, therefore, would simultaneously address climate and non-climate impacts.[16] In sum, we recommend that ARB: (1) abandon the bespoke leak emission reduction concept; or (2) to the extent ARB desires such CH_4 emissions to be mitigated, utilize compliance instruments and procedures already in place via participation in the Cap-and-Trade Program to achieve real and quantifiable emissions reductions.

IV. ENFORCEMENT PROVISIONS

Per Section 95674(c) of the discussion draft regulations: "Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate, violation of this subarticle." The operation of such an enforcement provision would be both draconian and unnecessary given the penalties specified in the Health & Safety Code for violations of emission regulations or limitations.

For example, the Health & Safety Code provides that any person who emits an air contaminant in violation of any rule or regulation of the state board or of a local air district pertaining to emission regulations or limitations (such as those in the discussion draft regulations), and who knew of the emission and failed to take corrective action within a reasonable period of time under the circumstances, is liable for a civil penalty of $40,000.[17] It is

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[15] ARB, California Air Resources Board's Process for the Review and Approval of Compliance Offset Protocols in Support of the Cap-and-Trade Regulation (May 2013)(available at http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf).

[16] *See* Cal Health & Safety Code § 38562(d)(1) and (2).

[17] Cal Health & Saf Code § 42402.2(a). Both lower and higher per violation penalties are provided in the Code, which differ according to assessed degrees knowledge and culpability.

conceivable that ARB or local air districts would seek such penalties given the aggressive leak repair timelines (which we consider unrealistic for the reasons described elsewhere herein) and the high probability that these leak repair timelines will be exceeded by regulated parties. If such a penalty were sought, it would equate to a cost of approximately $1,905 per $MTCO_2e$ emitted.[18] This cost would dwarf by orders of magnitude both the marginal abatement cost of reducing GHG emissions and current prices for Cap-and-Trade Program compliance instruments, not to mention voluntary market credit prices.[19]

Moreover, operators of affected facilities already have ample motivation to avoid emissions of CH_4, both from an economic perspective (as CH_4 is a valuable commodity) and due to the operation of existing laws and regulations. We also note that the enforcement provisions present in the prior discussion draft of the regulations provide ARB and the local air districts with plentiful enforcement powers. Further deterrence is unnecessary, particularly via imposition of draconian penalties such as that in Section 95674(c) of the discussion draft regulations. Accordingly, we recommend that ARB remove this provision from the regulations.

If ARB declines to remove the discussed penalty provision from the regulations, then we recommend, at a minimum, insertion of a safe harbor clause for offsetting excess emissions, such as the following:

> § 95674. Enforcement. … (c) Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate, violation of this subarticle **unless such metric ton or its carbon dioxide equivalent is fully offset (for example, but without limitation, via participation in the Cap-and-Trade Program or the retirement of voluntary market carbon credits)**.

V. ADDITIONAL SPECIFICITY NEEDED ON EVALUATION CRITERIA FOR SURFACE LEAK MONITORING PLANS

Section 95668(h)(2) of the discussion draft regulations require each affected facility to develop a plan for surface leak monitoring and indicates that the "plan will be evaluated based on sensitivity of instrumentation, coverage of the facility, appropriateness for site, and other relevant criteria. The ARB Executive Officer will approve, in full or in part, or disapprove, in full or in part, the plans with full implementation of monitoring by January 1, 2018."

We request that ARB provide additional specificity concerning the "other relevant criteria" that will be used to evaluate said plan. Additional specificity will allow for the preparation of surface leak monitoring plans that are more likely to meet the Executive Officer's expectations. Further, additional information is needed to flesh out the implications of the

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[18] The cost per $MTCO_2e$ emitted was calculated using the 100-year GWP value for CH_4 provided in the MRR.

[19] The settlement price at the November 2015 Cap-and-Trade Program allowance auction for current vintage allowances was $12.73, or approximately 0.67% of the possible penalty cost per $MTCO_2e$.

Executive Officer disapproving a plan in whole or in part. Will such disapproval push an affected facility out of compliance or will there be a safe harbor for facilities that timely submit plan applications and respond to associated requests for information and/or actions from the Executive Officer? What if the Executive Officer fails to take any action to approve or disapprove a plan by the deadline of January 1, 2018?

To address these questions, we recommend the following edits to Section 95668(h)(2):

> By January 1, 2017, each facility shall develop a plan for surface leak monitoring at the facility on a continuous basis or, if continuous is not feasible, a daily basis. The plan will be evaluated based on sensitivity of instrumentation, coverage of the facility, appropriateness for site, and other relevant criteria **[to be expanded by ARB staff in future discussion draft or proposed regulatory language]**. The ARB Executive Officer will approve, in full or in part, or disapprove, in full or in part, the plans with full implementation of monitoring by January 1, 2018. **If the ARB Executive Officer takes no action to approve or disapprove the plans by January 1, 2018, said plans will be deemed to be approved. Timely submission of plans to the ARB Executive Officer and reasonably prompt responses to requests for information or modification of said plans will insulate affected facilities from a finding of a violation of this subarticle should, as a result of such requests, plans not be approved and/or fully implemented by January 1, 2018.**

VI. COST ESTIMATES

At the February 4 workshop, ARB indicated it plans to release a Staff Report and Environmental Analysis on April 1, 2016. Although summary cost information was provided at the workshop, detailed analysis of and comment on costs is precluded at this time. A few general comments can be provided regarding the cost-effectiveness data for the control options presented at the February 4 workshop:

- The cost-effectiveness estimates for the control options are generally based on the ICF report, which borrowed from EPA Natural Gas STAR documents. Gas STAR reductions and related studies were predominately “low-hanging fruit”. That is, companies selected control options, facilities, and operating scenarios that offered the best opportunity for low cost emission reductions. Thus, these cost data are not representative of the industry wide population of emission sources that would be covered by the proposed regulation, and very likely underestimate control costs across a broad segment of sources and operations.
- The ICF report acknowledges that cost-effectiveness analysis differs for the natural gas transmission sector because companies transport the commodity, do not own the gas, and derive no direct financial benefit from the economic value of the commodity. Cost-

effectiveness analyses should consider the different financial situation for natural gas transmission compared to other segments.

- As noted previously, a GWP based on a 100-year time horizon that is consistent with other state, federal and international convention should be used. Cost-effectiveness analyses presented at the February 4 workshop use a 20-year time horizon, which skews the analysis by roughly a factor of three when compared to conventional analyses.
- Collectively, these factors suggest that ARB has under-estimated the cost-effectiveness (i.e., $/ton for GHG emission reductions) of the proposed emission reduction requirements.

Again, SoCalGas and SDG&E thank you for this opportunity to comment on the Draft Regulation, and we look forward to additional dialogue as the Regulation finalizes. Please contact me if you have any questions or concerns about these comments.

Sincerely,

Jerilyn López Mendoza

Jerilyn López Mendoza
Environmental Affairs Program Manager – Air Resources Board
SoCalGas
and on behalf of SDG&E

ATTACHMENT: PROPOSED REGULATION REVIEW (BY SECTION)

LDAR (§ 95669) – Methods and Standards

- Methods for leak detection should include Optical Gas Imaging (OGI) to identify leaks, with Method 21 then used to measure the leak concentrations. Or, an operator could elect to repair the leak without completing a Method 21 measurement. The proposed NSPS, Subpart OOOOa requires OGI but EPA solicited comment on whether additional methods, such as Method 21, should be allowed for leak detection. Many comments recommended allowing OGI or Method 21 (see docket number EPA-HQ-OAR-2010-0505) and both methods may be in the Subpart OOOOa final rule. Similarly, Subpart W annual leak surveys allow the use of Method 21 or OGI. We recommend that ARB comport with federal requirements and allow OGI or Method 21.

- We recommend that ARB delete the punitive measures in § 95669(o), Tables 3 and 4, that prescribe the allowed number of leaks above a defined Method 21 leak screening concentration. The purpose of an LDAR program is to find and repair leaks, and punishing an operator for leak discovery is inconsistent with existing LDAR programs or a productive program. ARB has provided no information to indicate that ongoing leak surveys will eliminate "new leaks" above a certain threshold.

  This measure would also preclude the use of OGI for leak identification. For example, an operator could use OGI to identify a leak from an elevated compressor vent that is very difficult to access for Method 21 screening. The repair could be completed and verified with OGI without requiring extreme and unsafe measures to complete a Method 21 screening.

  In addition, it is understood that while Method 21 concentration may qualitatively indicate leak size, concentration is a poor indicator of the quantitative leak rate. Material previously submitted during this process shows study results from transmission compressor stations that indicate that the *mass emission rate* for leaks with similar Method 21 concentrations can differ by three or more orders of magnitude. Thus, it is very unlikely that ARB can complete an analysis that quantitatively justifies the proposed measures, because mass emissions cannot be accurately quantified based on Method 21 concentration.

  Definitive studies are not available to assess the frequency and reoccurrence of leaks from natural gas systems. Compared to an "uncontrolled" facility, over time an ongoing LDAR program will generally result in fewer leaks and fewer large leaks. However, we are unaware of any studies that document that the frequency or size of leaks in §98669(o) Tables 3 and 4 are precluded by a rigorous LDAR program. Again, we recommend that section be deleted.

- § 95669 (f)(1)(A) includes incentives to decrease the leak survey frequency. We recommend that ARB use an approach consistent with the Subpart OOOOa proposal, which allows a decreased survey frequency after two consecutive surveys that meet the performance objective [see 40 CFR, §60.5397a(i)]. The ARB proposal is too restrictive, especially since more frequent surveys are triggered if the performance objective is not met in any subsequent survey.

- The proposed AVO schedule is not supported and we are unaware of any study that justifies daily or weekly AVO. Additional comment can be provided in response to justification in the support documents planned for release on April 1. While environmental benefits of ARB's proposed schedule are uncertain, for unmanned facilities it is possible that a negative net environmental impact to conduct the inspection (from transportation, etc.) would occur.

- Section (l) requires capping open-ended lines. We strongly recommend this be deleted because these lines are typically open for specific operational or safety-related reasons. Closing off the line will result in a safety or operational problem in most cases. For example, OELs are often vent lines with venting occurring for safety reasons. Venting may occur infrequently but the line must be accessible for that function. A leak from the associated equipment could develop and release to atmosphere via that line. However, the solution is to address the repair (when a leak occurs) and not cap the line. Due to the nature of OELs, if emissions are seen, it is important for the survey team to understand whether that is appropriate process venting, or a leak from associated equipment.

<u>LDAR (§ 95669) – Repair Schedules and Delay of Repair</u>

- The proposed repair schedules do not include "delay of repair" provisions common for LDAR programs. The "critical components" allowance in § 95670 is too limiting to address common scenarios.
- Common delay of repair provisions consider environmental, operational, and reliability issues. For example, repair may require venting / blowdown of facility systems that result in emissions that far outweigh the leak. That simple environmental qualifier should be allowed as a basis for delay of repair without requiring review and approval by the ARB Executive Officer.

  An operational and reliability example: parts availability and timing of repair once the part is received. For example, some valves / parts are not "off the shelf" items and require fabrication that could take several months or more. Some unique cases could exceed the 180 day maximum in the rule. Once received, additional factors can affect the schedule, such as the potential for blowdown emissions offsetting the leak emissions and the need to avoid unnecessary shutdown of a facility or process during a time of high natural gas demand – i.e., circumstances could arise where multiple factors affect the repair timing. Reasonable delay of repair provisions should be integrated within the rule, consider these factors, require the operator to document the process, and ensure that repairs are completed as soon as practical.

  - We recommend ARB consider delay of repair provisions in EPA NSPS (e.g., Subpart VVa) and state regulations. For example, CDPHE (Colorado) rule provisions include:
    - If parts are unavailable, the operator must order parts promptly and complete repair within 15 working days of parts receipt (or the next shutdown after the part is received if repair requires shutdown); and
    - If delay is attributable to other good cause, complete repair within 15 working days after the cause of delay ceases to exist. (Operator documents the "cause.")
- In § 95670(d), owners and operators should have some recourse if an application for approval of critical components is denied.

<u>Standards (§ 95668) – Miscellaneous Comments</u>

- (c)(3)(B): The rule should not require an operator to "replace" an existing vapor control device if it complies with the specifications in § 95668(c)(4).
- (d)(2): The rule should allow reciprocating compressor rod packing replacement intervals specified by Subpart OOOO as an alternative practice.
- (d)(1)(A) and (d)(2)(A) and (e)(2): The phrase "driver engines and" should be deleted from these sections. The compressor driver does not have gas containing components, other than the fuel line which would already be covered by LDAR.
- (d)(2)(C) and (e)(4): Ports should be installed six feet above ground level <u>or a platform</u>.
- (f)(2) – (3): As noted below regarding the definition of "continuous bleed," sections (f)(2) and (3) should not delete the term "continuous bleed." That descriptor is needed to differentiate the "continuous bleed pneumatic devices" in (f)(2) – (3) from intermittent devices addressed by (f)(4).
- (g)(1)(B): The volumes of gas vented during a well unloading are greater than volumes and rates that can be measured using the bagging and high volume sampling methods. It is doubtful that well unloading events can be measured safely or accurately using any existing methods.

<u>Critical Components (§ 95670) – Miscellaneous Comments</u>

- (b): The number of "critical components" associated with a "critical process unit" could number in the hundreds, and completing Table A3 "Designated Critical Component Form" for each and every critical component is impractical and unnecessary. Table A3 should be modified to only list critical process units at a facility, and all the rule text modified to indicate that all components associated with such units would be designated as critical components (i.e., it is not technically feasible to repair a leak from an associated component without shutting down the critical process unit and opening the process to atmosphere).
- (b): The Designated Critical Component Form filing and approval process will be completed after the LDAR requirements are initiated. The rule should allow critical components identified in a properly submitted Designated Critical Component Form to be subject to the appropriate critical component repair schedule until CARB approves or disapproves the application.

<u>Other Issues</u>

- Appendix A "Recordkeeping and Reporting Forms": The rule should allow alternative recordkeeping and reporting forms provided the forms include the information requested in the appropriate Appendix A form.
- Schedules: The rule includes prescribed dates that may not allow enough time (for example, initial requirements apply on January 1, 2017). Additional consideration is required for the deadlines, especially initial deadlines. Rather than specific dates, the rule should indicate initial applicability "X" days from rule adoption – e.g., 180 days from rule adoption.
- Comments on proposed Definitions (§ 95667):

- (a)(7): "Continuous bleed." Comment: This definition is included, but later rule text deletes reference to the term "continuous bleed" pneumatic device, deeming this definition superfluous unless other proposed rule text is revised. § 95668(f)(2) should be revised to refer to "continuous bleed" pneumatic devices.
- (a)(22): "Leak or fugitive leak." Comment: The leak thresholds are not a "rate," but rather a concentration measured by Method 21.
- (a)(37): "Pneumatic device." Comment: A device that uses electricity to power the controller is not a pneumatic device.
- (a)(49): "Separator." Comment: Defining a separator as a tank is confusing and contradicts the definitions of "Tank" and "Separator and tank system." These three definitions need to be reviewed and revised for consistency and consideration of the various designs and operations throughout the oil and gas industry.

- § 95672 Reporting Requirements. Reporting requirements in (a)(1) for Flash Gas Testing should be limited to GHG emissions (i.e., CH_4 and CO_2) and applicable supporting documentation. H_2S, N_2, BTEX, C2-C9, and C10+ are not GHGs and are not covered by the proposed rule, and the molecular weight of the gas sample is not required to estimate GHG emissions. Analysis for and reporting of those constituents is an unwarranted expense and should not be required.
- Appendix C – Test Procedure for Determining Annual Flash Emission Rate of Methane for Crude Oil, Condensate, and Produced Water. The Flash Gas analysis should be limited to procedures required to determine the emissions of the greenhouse gases CH_4 and CO_2. This would include measurement of the gas-to-oil ratio or the gas-to-water ratio, and the volume percent of methane and CO_2 in the flash gas sample. H_2S, N_2, BTEX, C2-C9, and C10+ are not GHGs, and analysis for these compounds is unnecessary for a GHG rule.