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Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed Second 15-Day Modifications to the Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Dear Board Members:

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E), appreciate the opportunity to submit these written comments concerning the Proposed Second 15-Day Modifications to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR). We thank the Air Resource Board (ARB) Staff for their interest and consideration of stakeholder input and the changes to the proposed amendments as reflected in the Second 15-day Modifications. SoCalGas and SDG&E appreciate Staff's outreach efforts in developing these proposed modifications and we hope to further the development of the MRR with these comments on the Second 15-day changes.

As mentioned above, Staff's consideration of stakeholder input has been productive, enhancing understanding and facilitating technical aspects for reporting under a cap and trade program. Many elements of the California Mandatory Reporting Program are now more closely aligned with the EPA program. Several comments below discuss other opportunities for consistency between the two similar regulations.

Most importantly, SoCalGas and SDG&E include below an extensive discussion related to the use and the definition of the term "pipeline quality natural gas." We recommend that ARB amend this term several times in this regulation and our analysis indicates these changes will not change the context or meaning. In this section we also include a request to exclude the 90% methane specification pending further analysis, as this exclusion currently serves no purpose in the context of the MRR.

General Comments:

Section 95102. Definitions.

Comment: The word "quality" in the definition of "Pipeline Quality Natural Gas" is used in the context of these regulations to define a default "range" for purposes of MRR calculations. The word "quality" can be eliminated to avoid confusion without changing the meaning or function.

The California Public Utility Commission (CPUC) adopts natural gas specifications that utilities must adhere to in delivering natural gas to their customers. Because the CPUC has authority over natural gas quality issues, ARB should choose a different term to define the "default range" for the calculations required under this regulation to avoid implying that ARB is assuming jurisdiction over gas quality issues.

The word "quality" implies a standard or grade that has an intrinsic value, characteristic or feature. In many cases the word "quality" is used to imply excellence or grade and implies a positive connotation wherein anything that is not "quality" creates a negative connotation. The use of the word "quality" in this regulation may create a level of confusion among natural gas customers because it could be construed as implying that gas that meets pipeline specifications is nevertheless not "pipeline quality."

Comment: In addition to the fact that the CPUC adopts natural gas specifications that utilities must adhere to in delivering natural gas to their customers, it must be noted that requiring at least ninety percent methane by volume would narrow the number of sources that can apply a default value to emissions calculations, while serving no relevant purpose in either the MRR or the Cap and Trade regulation. Moreover, this added restriction may cause natural gas users to conduct excessive analysis with insignificant results. SoCalGas and SDG&E request that ARB exclude the ninety percent methane requirement from this rule pending further study of the effects and burden of this "enhanced" reporting requirement.

Delete and Modify

Section 95102 Definitions.

The word "quality" as related to "pipeline quality" and "pipeline quality natural gas" should be deleted in entirety from the following definitions and throughout this regulation.

The portion of Section 95102 (288) "and which is at least ninety percent methane by volume," should be deleted.

(251) "Natural gas" means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons and carbon dioxide. Natural gas may be **for** field **use** ~~quality~~ (which varies widely) or pipeline ~~quality~~ **natural gas**. For the purposes of this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

(288) "Pipeline ~~quality~~ natural gas" means, for the purpose of calculating emissions under this article, natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, ~~and which is at least ninety percent methane by volume~~, and which is less than five percent carbon dioxide by volume.

(392) "Transmission pipeline" means a high pressure cross country pipeline transporting sellable ~~quality~~ natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Section 95103. Greenhouse Gas Reporting Requirements.

Comment: Section 95103(j) deals with Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels. Biogas and biomethane are biomass-derived fuels subject to identical transportation systems. Section 95103(j)(3) should include the requirement that both biogas and biomethane suppliers produce documentation including invoices, shipping reports, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts for verifier or ARB review to demonstrate the receipt of eligible biogas and biomethane.

Modify

(3) When reporting ***biogas and*** biomethane, documentation including invoices, shipping reports, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts must be made available for verifier or ARB review to demonstrate the receipt of eligible ***biogas and*** biomethane.

Section 95115. Fuel Combustion Sources

Comment: Natural gas is not included in the listing of default CO_2 emission factors and high heat values in Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1). Table 1 appears to limit the fuels for which the Tier 1 methodology can be used for CO_2 emission estimates and does not include CH_4 and N_2O emission estimates. On the other hand, the United States Environmental Protection Agency (EPA) has chosen to include these fuels (*e.g.*, natural gas) in Table C-2, 40 CFR 98 Subpart C when determining default high heat values and default CO_2 emission factors. Likewise, the EPA has determined that CH_4 and N_2O emissions can be estimated using the Tier 1 methodology, but allows that CO_2 must be estimated using a higher-tier methodology. The different reporting methodologies cited above will unnecessarily complicate the calculation of these values when reporting to the agencies.

Modify

Replace Section 95115 Table 1 with Table C-1, 40CFR 98 Subpart C (as shown below)

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO_2/mmBtu
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1 .	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97

Comment: Section 95115(e)(3) Procedures for Biomass CO_2 Determination states that reporting entities must use the procedures proscribed in this section when calculating emissions from biomass-derived fuels that are mixed with fossil fuels prior to measurement. As previously discussed, this section also has a procedure for calculating emissions from a biomethane and natural gas mixture, but fails to include biogas. Yet the "total biomethane deliveries" required for calculating the emissions of biomethane are subject to the values and the same verification requirements as biogas in Section 95131(i)(2)(D) ("For biomethane and biogas, the verifier must: 1. Examine all nomination, invoice, scheduling, allocation, transportation, storage, in-kind fuel purchase and balancing reports....").

Modify

Section 95115(e)(3) When calculating emissions from a ***biogas or*** biomethane and natural gas mixture as described in 40 CFR §98.33(a)(2) using the annual MMBtu of fuel combusted in place of the product of Fuel and HHV in Equation C-2aa Tier 2 method, the operator must calculate emissions based on verifiable contractual deliveries of ***biogas or*** biomethane subject to the requirements of 95131(i), using the natural gas emission factor in the following equations:

And modify all other calculations in this section

Section 95153. Calculating GHG Emissions.

Comment: Section 95153(d). The equation should have 100 in the denominator (to convert %G to a mole fraction)

Modify

§ 95153 (d)(1) For dehydrators that use desiccant.....

$$E_{s,} = n(H * D_2 * \pi * P_2 * \%G)/(4 * P_1 * 1{,}000 cf/Mcf)\ \mathbf{100}$$

Comment: Section 95153(t). Equation should be changed to correspond to most recent Subpart W proposed revisions.

Modify

§95153(t) GHG Mass Emissions. The operator must calculate GHG mass emissions using the following equation:

P=Density of GHG i. Use ~~**0.0538**~~ **0.0520** kg/ft3 for CO_2 and N_2O, and ~~**0.0196**~~ **0.0190** kg/ft3 for CH_4 at 68°F and 14.7 psia or 0.0530 kg/ft3 for CO_2 and N_2O, and 0.0193 kg/ft3 for CH_4 at 60°F and 14.7 psia.

Comment: Section 95153(m). GHG emissions from centrifugal compressors can and do vary significantly depending on the type of seals and the size of the compressor. Ninety percent of all new compressors now have dry gas seal systems and dry seals tend to be the technology of choice for new compressors. Given this potential for very low emissions SoCalGas and SDG&E recommend that alternative emission estimation methodologies for centrifugal compressors less than 250 hp should be developed to ensure accuracy in reporting. Further discussion of this issue can be found in the referenced document[1].

Delete

~~§95153(m)(2) The operator must calculate CO2, CH4, and N2O (when flared) emissions for all centrifugal compressors with rated horsepower less than 250hp using the methodologies found in 40 CFR §98.233(o)(7).~~

We appreciate Staff's support of an open dialogue and stakeholder participation in discussing this regulation, and the opportunity to furnish these comments.

Yours sincerely,

Eugene Mitchell

[1] Natural Gas STAR Partners: REPLACING WET SEALS WITH DRY SEALS IN CENTRIFUGAL COMPRESSORS, Executive Summary http://www.epa.gov/gasstar/documents/ll_wetseals.pdf