Pacific Gas and Electric Company

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California Air Resources Board
1001 I Street
Sacramento, CA 95812-2828

Re: Pacific Gas and Electric Company's Comments on the Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Dear Board Members:

Pacific Gas and Electric Company ("PG&E") welcomes the opportunity to submit these comments on the Air Resources Board's ("ARB") proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas ("GHG") emissions. PG&E supports the efforts to harmonize the regulation with updates to the United States' Environmental Protection Agency ("U.S. EPA") Final Rule on Mandatory Reporting of Greenhouse Gases. PG&E's comments seek clarification on, and proposes, changes to items in the proposed amendments to the regulation.

A. Section 95152. <u>Gas Blowdowns on the Distribution System Should Be Estimated Rather Than Directly Measured.</u>

The revisions to Section 95152 include measuring and reporting emissions from equipment and pipeline blowdowns in the natural gas distribution system. (Section 95152(i)(5).) The U.S. EPA does not require facilities to report emissions from blowdowns on the gas distribution segment. Measuring the data as currently proposed using direct measurements would require significant additional time and resources and, given the small amount of gas typically involved, would not yield more accurate volumes than estimation using conservative assumptions. Additionally, it is important to note that reporting of this particular subset of natural gas emissions is not needed to support the state's cap-and-trade regulation since the natural gas compliance obligation under the cap is captured under Section 95122.

The data needed for the proposed reporting would require PG&E to develop and implement new systems, controls, work practices, and training. PG&E has over 40,000 miles of mains and over 2,700 regulator stations on its gas distribution system. PG&E would need to measure gas pressure and temperature at the site of a blowdown, which is not current practice, to calculate the volume of gas within the isolated pipeline segment or piece of equipment.

PG&E has incentives to minimize impacts to customers resulting from distribution blowdowns. PG&E minimizes the length of pipe to be removed from service, and the pipe segment to be evacuated is typically a city block or less. Consequently, the amount of gas released during a distribution blowdown is small. Direct measurements of temperature and pressure would be cumbersome to execute and, given the small amount of gas typically involved per instance, would not yield more accurate volumes than estimation using conservative assumptions. Therefore, PG&E urges ARB to modify the requirement set forth in subsection 95152(i)(5) to permit the use of engineering calculations based on known pipeline segment diameter, using conservative assumptions about segment length, pressure and temperature.

B. Section 95153. Modifications Should Be Made to Requirements for Pneumatic Devices.

In its August 11, 2011, comments on ARB's proposed modifications to the regulation, PG&E raised concerns regarding safety issues associated with installing meters on every pneumatic device. In response, ARB adopted the following language in Section 95153, which eliminated the requirement for local distribution companies such as PG&E to install meters on pneumatic devices by January 1, 2015.

> The operator who is a local distribution company reporting under Section 95122 of this article must comply with 40 CFR §98.233 in reporting emissions from the applicable source types in Section 95152(e)-(i) of this article. Other operators must comply with 40 CFR §98.233 in reporting applicable emissions by source type, except as otherwise provided in this section.

This language has apparently been deleted from the amended version of regulation, but it was not shown as a strikeout edit. This should be corrected to align the regulation with federal requirements and to avoid potential safety issues.

In addition, PG&E suggests that the language be further refined to exempt intermittent bleed devices from the requirement to install metering, since they do not emit gas on a continuous basis. (These devices only emit gas when they are used to open or close a valve, or any other actuating function.) PG&E recommends that ARB should concentrate on reducing emissions from high bleed continuous devices and then determine if there would be benefits to installing meters on all devices. PG&E suggests the following modification to Section 94153(a):

> *(a) Metered Natural Gas Pneumatic Device and Pneumatic Pump Venting.* … By January 1, 2015, natural gas consumption must be metered for all of the operator's pneumatic continuous high bleed devices and pneumatic pumps.

Lastly, PG&E notes that Section 95153(a) states that "[f]or unmetered devices the operator must use the method specified in Section 95153(a)." It appears that this cross-reference was intended to be 95153(b), which contains the method for determining these emissions.

C. Section 95153(o)(8)(A). ARB Should Provide Regulatory Guidance Regarding Leak Surveys To Align With Federal Requirements.

Section 95153(o)(8)(A) requires PG&E to conduct leak surveys at each Transmission-to-Distribution transfer station over a five year period with some flexibility about how many stations are surveyed each year. The language of this section is the same language as U.S. EPA's Subpart W regulation, and specifies that the number of stations monitored in each year should be "approximately equal" across all years in the cycle.

U.S. EPA has provided guidance about how the term "approximately equal" can be applied in conducting leak surveys at these stations over a five year period. U.S. EPA allows reporters to conduct leak surveys at 10% of the stations in each of the first two years followed by 40% in year 3 and 20% each in years 4 and 5. PG&E requests that ARB issue similar regulatory guidance to provide the same flexibility as U.S. EPA in implementing these leak surveys over the five-year period. The following link contains Questions and Answers on U.S. EPA's GHG reporting rule:

http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=118587545

D. Section 95102 and 95112. PG&E Supports ARB's Proposed Amendments to the Cogeneration Provisions and Requests ARB to Make Aggregated CHP Data Publicly Available.

PG&E supports changes made in Sections 95102 and 95112 that further clarify reporting of electrical and thermal output of cogeneration facilities. The modified requirements enhance ARB's ability to collect the necessary data to evaluate efficiency and GHG performance of cogeneration systems and better understand when thermal energy is being utilized rather than being vented or discharged without use.

Efficiency and GHG performance is the essential driver of cogeneration/combined heat and power (CHP) policy in California. We ask that ARB develop and publicly present aggregated CHP efficiency information collected through the Mandatory Reporting Regulation and develop a system to cross-check the data with similar information reported to the Energy Information Administration, Federal Energy Regulatory Commission, and the California Energy Commission. We also encourage ARB to train verifiers to properly asses the validity of this data. We believe that such efforts will help inform the implementation of CHP policies, assist with the update to the ARB's Scoping Plan scheduled for next year, and help to achieve California's AB 32 GHG reduction goals.

E. GHG Benefits or Disbenefits from Cogeneration Should Be Calculated, Aggregated, and Presented Publicly by ARB Using MRR Data.

PG&E seeks clarification regarding how the data reported on CHP electrical and thermal output will be used by ARB to evaluate system efficiency and the GHG benefits of CHP. Below we describe our understanding of how the reported data could be used.

The total energy efficiency (η) of any CHP system can be defined as:

$$\eta = \frac{Energy\ Output\ Used}{Energy\ Input}$$

Under the MRR rule, the following data is reported to ARB:

Data Reported	Units	Section
The energy input of a CHP unit is the total fuel energy ($\mathbf{F_{MMBtu}}$) consumed annually in a cogeneration facility, expressed on a high heating value (HHV) basis	MMBtu	95112(b)(4) and (6)
$\mathbf{H_{Sold}}$ is the "thermal energy provided or sold to particular end-users"	MMBtu	95112(a)(5)(A)
$\mathbf{H_{Used\ Onsite}}$ is the "generated thermal energy that is used by those on-site industrial processes or operations and heating or cooling applications"	MMBtu	95112(a)(5)(C)
$\mathbf{P_{MWh}}$ is the net electricity generated annually (reported in MWh)	MWh	95112(b)(2)
E is the total annual direct GHG (CO_2e) emissions from the cogeneration facility	MT	Can be estimated from 95112(b)(4)-(8). (Other methods may be required by Subparts C and D of 40 CFR Part 98.)

Physical Constants	
0.05307	MT CO_2e/MMBtu Natural Gas Fuel Energy
3.413	MMBtu/MWh
2,205	lbs/MT

We believe that the reported data could be used as follows:

Interpreted Use of Reported Data	Units	Notes
$\mathbf{H_{MMBTU}} = \mathbf{H_{Sold}} + \mathbf{H_{Used\ Onsite}}$ is the thermal output used (thermal output that is used on site or sold).	MMBtu	Sum of values from 95112 (5) (A) & (C)
$\mathbf{P}_{\mathbf{MMBtu}}$ is the net electrical output converted from MWh to MMBtu	MMBtu	$P_{MMBtu} = 3.413 * P_{MWh}$

Therefore, the total energy output used from the facility is the sum of net power output and used thermal output	MMBtu	$\text{Used Energy}_{\text{Output}} = P_{MMBtu} + H_{MMBtu}$

Thus, the total energy efficiency of a cogeneration facility can be evaluated as:

$$\eta = \frac{P_{MMBtu} + H_{MMBtu}}{F_{MMBtu}}$$

Energy efficiency information of a cogeneration facility can further be translated into GHG emissions efficiency using a 'double benchmark' standard. Conceptually, the double benchmark compares emissions from the CHP facility to the amount of GHG emissions that otherwise would exist if the CHP Facility did not operate (and the CHP energy was supplied through separate heat and power production).

A "GHG efficient" CHP refers to one that reduces emissions as compared to the double benchmark. A "GHG inefficient" CHP refers to one that increases GHG emissions as compared to the double benchmark.

The double benchmark approach was adopted as an acceptable way to determine GHG efficiency in the California Public Utilities Commission (CPUC) approved QF/CHP Settlement.[1/] The current double benchmark is:

- **Electricity:** The reference for electricity generated is a natural gas facility with an 8,300 Btu/kWh HHV heat rate (at the busbar and excluding line losses). This value is equivalent to a GHG emission factor of 0.4405 Metric Tons (MT) CO_2e per MWh of electricity.
- **Used Thermal Energy:** The thermal efficiency is set equal to a reference boiler of 80% efficiency. This is equivalent to a GHG emission factor of 0.06634 Metric Tons CO_2e per MMBtu of used thermal energy.[2/]

The actual GHG emissions from a CHP facility under the QF/CHP Settlement can be compared to the double benchmark to evaluate overall GHG benefit or dis-benefit of a given CHP facility.

Comparison to double benchmark:

$$GHG^{DB} = \left(0.4405 \frac{MT}{MWh}\right) * P_{MWh} + \left(0.06634 \frac{MT}{MMBtu}\right) * H_{MMBtu}$$

1/ CPUC Decision 10-12-035.
2/ QF/CHP Settlement Term Sheet, Sections 7.1 - 7.2. Available from: http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF

where, GHG^{DB} = GHG Emissions from separate heat and power production per the double benchmark

Recall from above that E is the actual GHG emissions of the CHP facility.

If $E \leq GHG^{DB}$: The facility is a GHG efficient cogeneration facility

Otherwise $E > GHG^{DB}$: The facility is a GHG inefficient cogeneration facility

We encourage ARB to calculate where existing CHP facilities operate in relation to a double benchmark to help inform its update to the AB32 Scoping Plan.[3/]

F. Section 95156. <u>The Proposed Additions to Address Cogeneration Should Be Clarified.</u>

Requirements related to reporting of total thermal output and net electricity generation output from cogeneration at onshore and offshore petroleum and natural gas production facilities in Section 95156 (at the basin level) should be more clearly connected to what is required at the unit and facility level pursuant to Section 95112. The requirement in Section 95156(a)(3)(A) and (B) to assess the "portion of CO_2e emissions associated with" either thermal or electric output without a clear methodology for conducting this allocation may be problematic. (ARB previously included a method for conducting such an allocation of emissions between energy streams in the 2007 versions of Section 95112 of the regulation, which was subsequently deleted.) PG&E recommends that this language be eliminated so that the Section reads as follows:

(3) For cogeneration sources:
- (A) Total thermal output (MMBtu) ~~and the portion of CO_2e emissions associated with this output~~;
- (B) Net electricity generation (MWh) ~~and the portion of Co_2e emissions associated with this generation~~;
- (C) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) ~~and the portion of CO2e emissions associated with this generation~~;

3/ PG&E supports the CPUC-approved double benchmark for procurement under the QF/CHP Settlement. For other CHP or future programs, updated benchmarks should be used for electricity and heat. For electricity, the report CEC-200-2011-008 indicates that the weighted-average heat rate of California's gas-fired power plants in 2010 was 7,577 Btu/kWh, substantially more efficient than the 8,300 Btu/kWh figure in the Settlement. For useful heat, several firms offer new heaters or boilers with efficiencies of 90% or more, compared to the 80% figure in the Settlement, as noted in PG&E's comments on CHP to the CEC (see p.3 at http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2012-03-12_TN-64134.pdf).

G. Section 95103. ARB Should Modify its Measurement Accuracy Requirements.

By reference to 40 CFR 98.33(a)(4), Section 95103(k) allows Electricity Generation Units subject to 40 CFR §75 to elect to use Part 75 methods to calculate CO2 emissions and requires the measurement devices on these units to be subject to Part 75 requirements, consistent with 40 CFR §98.44. In order to assure regulatory clarity for reporters and verifiers, PG&E recommends that the language be modified as follows:

> *(k) Measurement Accuracy Requirement*… . [T]he provisions of paragraph K1-K11 do not apply to: stationary fuel combustion units that use the methods in 40 CFR §98.33(a)(4) to calculate CO2 mass emissions; stationary fuel combustion units that report using methods in 40 CFR §98.44; emissions reported as *de minimis* under section 95103(i); and devices that are solely used to measure parameters used to calculate emissions that are not covered emissions.

Additionally, Section 95103(k)(6)(A)(1)(b) requires that the primary element (e.g. orifice plate) "be photographed on both sides prior to any treatment or cleanup of the element to clearly show the condition of the element as it existed in the pipe." In the case of pipeline quality natural gas flowing across an orifice plate, it is highly unlikely that the condition of the plate will change. Additionally, routine meter calibration is a good indicator of orifice plate health. Therefore, PG&E suggests that this requirement be deleted if natural gas is the fuel being measured.

H. Section 95102. ARB Should Make A Minor Revision to the Definition of Asset-Controlling Supplier.

An Asset-Controlling Supplier cannot be assigned a specified source emission factor because it is not a specified source but rather the owner, operator, or marketer of a number of sources. Therefore, PG&E proposes a slight modification as follows to conform with the terms in the methodology for calculating this emission factor.

> "Asset-Controlling Supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier specific identification number and ~~specified source~~ system emission factor by ARB for the wholesale electricity procured from its system and imported into California."

I. PG&E Recommends Other Refinements to the Regulation.

Remove Six-Year Limit for Verifiers. Section 95130(a)(2) includes a six-year limit for the same verification body or verifier(s) to perform verification services for a reporting entity, including time spent on verifications performed for the California Climate Action Registry, The Climate Registry, or Climate Action Reserve. PG&E believes this limitation is unnecessary and creates inefficiencies as verifiers constantly move around among reporting entities.

PG&E and other investor owned utilities report under several different sectors annually, including Electric Power Entities, Electricity Generation and Cogeneration Units, Stationary Fuel Combustion sources, Suppliers of Natural Gas, Natural Gas Liquids and Liquefied Petroleum Gas and Petroleum and Natural Gas Systems. The diversity and complexity of our business and operating system requires adequately qualified and experienced verifiers who understand both the regulation and the business operation to perform verification services. We have found that takes a great deal of time for a verifier to understand the complexity and uniqueness of our business, and we are concerned that the time restrictions placed on verifiers result in an unnecessary burden to both reporters and verifiers to learn and re-learn the utility business. A verifier who is familiar with the business operation can objectively review any operational changes and identify compliance concerns more efficiently than an inexperienced verifier.

PG&E believes that the rigor established in the regulation is sufficient to assure high quality verifications of reported emissions, and there is no need to restrict qualified professionals from providing on-going services. The regulation already contains requirements for individual and lead verifiers to meet minimum qualifications, and for ARB to authorize verification bodies, lead verifiers and verifiers after evaluating potential conflicts of interest. Therefore, PG&E recommends that Section 95130(a)(2) be deleted.

Stationary Combustion Sources Providing Power Only Inside a Facility. PG&E has two locations where stationary combustion sources are used to compress natural gas and provide electric power only <u>inside</u> the facility boundary. These facilities are subject to cap-and-trade obligations for the GHG emissions from sources within each facility. U.S. EPA regulations (40 CFR §98.3) permit all facility emission sources to be grouped for purposes of reporting emissions. PG&E recommends the following modifications to clarify that such aggregation is permissible under ARB's regulation as well.

> Section 95103(h). *Reporting ~~in~~ <u>Starting</u> 2012*.
> For emissions data reports due in 2012, facility operators may report 2011 emissions using applicable monitoring and calculation methods from 40 CFR Part 98. For entities not required to report 2011 emissions under 40 CFR Part 98, best available data and methods may be used for the 2011 data year. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012. For 2012 reports of 2011 emissions by facilities and suppliers, the missing data substitution requirements specified in this article that are different from the requirements of 40 CFR Part 98 do not apply; missing data for the 2012 report of 2011 emissions must be substituted according to the requirements of 40 CFR Part 98. <u>Beginning with emissions data reports due in 2013, facility operators with stationary emission sources included in Section 95112 that do not provide or sell any generated energy outside of the facility boundary may report emissions using applicable monitoring and calculation methods from 40 CFR Part 98.</u>

Section 95112(a). *Information About the Electricity Generating Facility*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating facility is required to include in the emissions data report the information listed in this paragraph, unless otherwise specified in paragraphs (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in Section 95112(a)(4)-(6) is optional for facilities that do not provide or sell any generated energy outside of the facility boundary. Notwithstanding the information specified in Section 95112(a)(1)-(3), operators of a facilities that do not provide or sell any generated energy outside of the facility boundary are not subject to the other provisions of Section 95112.

Section 95115(h). *Aggregation of Units*. Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs 95101(a)(1)(A)-(B), and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or (c)(4), must not aggregate units that belong to different source categories, unless the facility operates stationary combustion units subject to Section 95112 that do not provide or sell any generated energy outside of the facility boundary. For the purpose of unit aggregation, units subject to 40 CFR 98 Subarticle C that are associated with one source category must not be grouped with other Subarticle C units associated with another source category, except when 40 CFR §98.36(c)(2) applies. …

Thank you for the opportunity to submit these comments.

Very truly yours,

/s/

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cc: Richard Bode, via email
Dave Edwards, via email
Wade McCartney, via email