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California Air Resources Board
1001 I Street
Sacramento, CA 9 5814

Re: Pacific Gas and Electric Company's Comments on the Air Resources Board's October 28, 2010 Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions

Dear Dr. Kennedy:

Pacific Gas and Electric Company ("PG&E") welcomes the opportunity to submit these comments on the Air Resources Board's ("ARB") October 28, 2010, Revisions to the Regulation for Mandatory Reporting on Greenhouse Gas ("GHG") Emissions. PG&E appreciates ARB's efforts to harmonize its regulation with federal regulations issued by the U.S. Environmental Protection Agency ("EPA") and to streamline GHG reporting. PG&E has identified a number of instances where the regulation needs to be clarified or modified to fulfill ARB's objectives.

SUMMARY OF RECOMMENDATIONS

- Adopt EPA's definition of pipeline quality gas to be consistent with EPA's regulations;
- Refine monitoring requirements for small volume meters;
- Clarify how ARB will exercise its enforcement authority;
- Refine calculations of transmission losses;
- Adjust emission rates for *new* wholesale sales to reflect GHG impact of these transactions;
- Clarify the requirement for registration of specified sources and suppliers;
- Clarify the term "useful thermal output" to be consistent with federal regulations;
- Refine combined heat and power requirements;
- Exempt small quantities of non-pipeline quality gas from monthly carbon content calculations and instead use default emission factors for carbon calculations;
- Clarify reporting requirements for biofuels;
- Align natural gas Local Distribution Companies ("LDC") emissions calculations with federal regulations;
- Conform the regulation with EPA's recently-issued Subpart W;

- Clarify that combustion emissions of biogas from digesters are exempt from a compliance obligation; and
- Clarify the role of out-of-state renewable energy purchases in the cap-and-trade program.

DISCUSSION

SECTION 95102. ARB SHOULD ADOPT EPA'S DEFINITION OF PIPELINE QUALITY GAS.

Section 95102 (239) contains a definition of pipeline quality gas that is slightly different than the definition in EPA's reporting regulations. The definition is important because many reporting requirements can be met by certifying that the fuel used was "pipeline quality." PG&E recommends that ARB adopt the definition set forth in 40 CFR 72.2[1/] as noted below so that the state and federal reporting regulations are consistent.

> Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.

SECTION 95103. ARB SHOULD REFINE ITS MONITORING REQUIREMENTS FOR CERTAIN METERS.

Section 95103 (l) requires facility operators to "monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption quantities at least weekly" in order to support the missing data substitution procedures for fuel use. While PG&E understands the rationale for this requirement, many facilities have smaller meters from which data is collected only on a monthly basis. Therefore, PG&E proposes an exception to weekly recording of fuel consumption for meters where the fuel volumes are small (i.e., adding up to no more than 3 percent) compared to the total fuel volume consumed by the facility. The cost of replacing these smaller meters with ones that could be read weekly is not appropriate in light of the relatively small fuel volumes that they track. In addition, if these meters malfunction, the difference between what would have been the correctly metered fuel volume and the fuel volume determined after applying the missing data substitution procedures would not likely result in significant changes to the facility's emissions report.

There are also some facilities that do not have their own meters; they rely on utility meters to measure their fuel use. While usage data from larger utility meters is downloaded every day,

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1/ See EPA 40 CFR 72.2 at http://edocket.access.gpo.gov/cfr_2004/julqtr/pdf/40cfr72.2.pdf.

smaller utility meters are read only monthly (unless SmartMeters™ have been installed which record gas usage daily).[2/] These smaller meters must still meet stringent utility and industry standards for accuracy and reliability. For example, PG&E's tariffs require that its gas meters not exceed one percent over the proper registration; if meters malfunction, corrective action is taken, and standardized methods for estimating missing usage are applied.[3/]

Because of the low malfunction rate of utility meters, the standardized methods for estimating missing usage, the relatively small fuel volumes tracked by smaller meters, and the eventual replacement of smaller utility meters with SmartMeters™, PG&E proposes an exception to weekly recording of fuel consumption quantities for facilities that have smaller meters.

SECTION 95107. ARB SHOULD CLARIFY HOW IT WILL EXERCISE ITS ENFORCEMENT AUTHORITY.

Section 95107 strengthens ARB's enforcement authority and establishes a strict liability standard. Consequently, penalties could be imposed even in the absence of any knowing violation or intent to deceive. PG&E appreciates that stringent enforcement provisions are necessary to support the cap-and-trade program. However, PG&E believes that ARB should revise this section to ensure that penalties for violations are commensurate with the scope and severity of the violation and potential environmental harm.

Subsection (a) provides that each day or portion thereof that a report is submitted late, incomplete, or inaccurate constitutes a separate violation. Similarly, subsection (b) provides that any other violation of the reporting regulations also counts as a separate violation for each day or portion thereof. Subsection (c) provides that each metric ton of CO_2e emitted but not reported constitutes a separate violation, and subsection (d) provides that each failure to measure, collect, record, or preserve information as required constitutes a separate violation. Taken together, these provisions can result in multiple violations for a single error that could, in turn, lead to huge penalties far out of proportion to any actual harm.

Due to the new strict liability standard, an entity that is making a good faith effort to comply with the reporting requirements could nonetheless be exposed to significant penalties. Moreover, since the cap-and-trade regulations also contain enforcement provisions and the possibility of large penalties, entities could be exposed to separate penalties resulting from a single error.

In PG&E's view, the proposed mandatory reporting regulations should include violation provisions and penalty guidelines that ensure that penalties are appropriate for the nature of the violation and the resulting harm. In its Initial Statement of Reasons ("ISOR"), ARB staff notes that the penalty would ultimately be based on the factors set forth in Health and Safety Code section 42403, which includes the extent of harm, the nature and persistence of the violation, the length of time over which the violation occurs, the frequency of past violations, the record of

2/ http://www.pge.com/myhome/customerservice/smartmeter/facts/.

3/ See PG&E Gas Rule 17, section A (Meter Tests) on Sheet 2 of the Rule at http://pge.com/tariffs/tm2/pdf/GAS_RULES_17.pdf.

maintenance, the entity's actions to mitigate the violation, and the financial burden to the entity. Because enforcement of AB 32 is a critical component of overall program design, PG&E recommends that section 95107 of the regulations be modified to explicitly cross-reference section 42403 of the Health and Safety Code so that entities that are subject to the mandatory reporting regulations will have clear regulatory direction on how ARB's enforcement authority will be exercised.

SECTION 95111 (b)(1). ARB SHOULD REFINE ITS CALCULATIONS FOR TRANSMISSION LOSSES.

In discussions of transmission losses associated with electricity imports, it is helpful to distinguish losses that occur inside California from losses that occur outside California. Losses inside California are the losses involved in bringing imported electricity from the California border to the load center. Similarly, losses are involved in bringing electricity from any in-state generator to the load center. To provide equal treatment for generators and imports, ARB counts emissions at the point of delivery onto the California grid. For generators, that point is the busbar. For imports, it is the point of first delivery within California. Losses within California are accounted for automatically, because the total supply (in-state generation measured at busbar, plus imports measured at first point of delivery) exceeds retail sales. The difference is in-state losses.

As noted in the Staff ISOR, AB 32 requires accounting for transmission losses outside California. For imports from unspecified sources, the ISOR notes that the default emission factor of 0.435 metric tonnes per MWh includes 2 percent transmission losses.[4/] As noted above, in-state transmission losses are included automatically. Consequently, no additional transmission losses should be included. PG&E recommends that the calculation in section 95111 (b)(1) for unspecified imports be changed to delete references to transmission losses but to note that the emission factor used includes transmission losses, as follows:

b) Calculating GHG Emissions.

(1) *Calculating GHG Emissions from Unspecified Sources.* For electricity from unspecified sources, the electric power entity must calculate the annual CO2 equivalent mass emissions using the following equation:

$$CO_2e = MWh \times \cancel{TL \times} EF_{unsp}$$

Where:
CO_2e = Annual CO2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (metric tons).
MWh = Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.
EF_{unsp} = Default emission factor for unspecified electricity imports calculated

4/ ARB Staff ISOR, p.167.

and published on the ARB Mandatory Reporting website.
EF_{unsp} = 0.435 MT of CO2e/MWh for first points of receipt located in nonlinked jurisdictions. This factor includes a 2% increase to account for transmission losses from the point of origin to the first point of delivery within California.
EF_{unsp} = 0 MT of CO2e/MWh for points of receipt located in linked jurisdictions.
~~TL = Transmission loss correction factor.~~
~~TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.~~
~~TL = 1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.~~

Similarly, PG&E recommends that the calculation in section 95111 (b)(2) for specified imports be changed to allow use of a facility-specific loss factor, or the 2% default, but to remove any reference to losses within California, as follows:

(2) *Calculating GHG Emissions from Specified Facilities or Units*. For electricity from specified facilities or units, the electric power entity must calculate emissions using the following equation:

$$CO_2e = MWh \times TL \times EF_{sp}$$

Where:
CO_2e = Annual CO2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (metric tons).
MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.
EF_{sp} = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website.
EF_{sp} = 0 MT of CO2e for facilities located in linked jurisdictions and facilities, or units within facilities, below the GHG emissions compliance threshold for delivered electricity pursuant to the Cap-and-Trade Regulation
TL = Transmission loss correction factor.
TL = 1.02 when deliveries are not reported as measured at the busbar~~, and transmission losses are not made up in other electricity deliveries reported or from California sources~~.
TL = 1.0 when deliveries are reported as measured at the busbar~~, or transmission losses are made up in other electricity deliveries reported or from California sources~~.

SECTION 95111 (b)(3). ARB SHOULD ADJUST ITS EMISSION RATES FOR NEW WHOLESALE SALES.

This and related sections would require assignment of a multi-jurisdictional utility's portfolio-average emission rate to its sales to its long-standing retail and utility customers. This treatment would apply, for example, to PacifiCorp's sales to its customers in northwestern California, to Bonneville Power Administration's deliveries to the Surprise Valley Electrification Corporation for its customers in northeastern California, and to Sierra-Pacific Power Company's deliveries to its customers in the Lake Tahoe area. These deliveries are small, averaging about 110 MW for PacifiCorp, 10 MW for BPA's deliveries to Surprise Valley, and 90 MW for Sierra-Pacific, compared to a total California demand that averages about 34,000 MW.

PG&E believes that the ARB's approach makes sense for deliveries to the long-standing customers of each multi-jurisdictional entity. Each entity has assembled a portfolio of electricity supplies to meet the demands of its customers. The portfolio-average emission rate is appropriate for application to deliveries to those customers.

PG&E does not support applying portfolio-average emission rates to wholesale imports into California. Because marginal supplies of electricity are freely traded, an import into California's wholesale market, whether from BPA or PacifiCorp or some other entity, may reasonably be regarded as drawing from the same pool of marginal electricity supplies. Consequently, PG&E supports assigning the default emission rate of those marginal electricity supplies to wholesale imports from <u>any</u> entity. ARB has proposed to adopt 0.435 metric tonnes/MWh (including losses) as the default emission rate for imports from unspecified sources, based upon an analysis of marginal electricity supplies in the WECC.

SECTION 95111 (g)(1). ARB SHOULD AMEND REGULATIONS REQUIRING REGISTRATION OF SPECIFIED SOURCES AND SUPPLIERS.

This regulation states in part:

> (1) *Registration of Specified Sources and Suppliers.* Each electricity importer claiming specified sources or suppliers of electricity must register its specified sources and suppliers of electricity with ARB prior to January 1 of each reporting year.

ARB defines reporting year as "data year." Data year is defined by ARB as: "…the calendar year in which emissions occurred." Consequently, the effect of this regulation is to require registration of specified sources and suppliers before they are negotiated, executed, purchased or transacted in some cases. While PG&E holds some long-term power purchase contracts, PG&E is an active participant in electricity markets and cannot foresee all counterparties it may have dealings with in advance of the reporting year.

PG&E believes ARB intended for electricity importers to register specified sources and suppliers with ARB by January 1 of the year following the year in which emissions occurred. PG&E

suggests that the regulation clarify this provision. PG&E recommends a January 31st date to ensure correct registration of specified sources and suppliers of transactions that occur in the last weeks of December.

SECTIONS 95102 AND 95112. THE TERM "USEFUL THERMAL OUTPUT" SHOULD BE CLARIFIED.

PG&E believes that a few key changes are needed for Combined Heat and Power ("CHP") reporting, primarily around the definition, measurement, and reporting of "useful thermal output" ("UTO"). ARB has indicated that, consistent with the policies expressed by other state and federal agencies, the UTO reported should be the UTO used in a productive and beneficial manner. However, because ARB's definition of UTO in section 95102(a) does not explicitly require productive and beneficial use, PG&E suggests that the definition should be updated to reflect this intent and that corresponding changes be made in section 95112(b).

Understanding the thermal output quantity that is actually used and displaces a boiler is critical to understanding the GHG emissions reductions associated with CHP. PG&E recently signed a multi-party settlement that sets up a procurement program for CHP; among other things, this program incorporates the ability to evaluate efficiency criteria to measure GHG emissions reductions and references ARB reporting. ARB and other stakeholders will need quality information on the UTO definition, measurement, and reporting to ensure that the CHP for which utility ratepayers pay is reducing GHG emissions.

As an outcome of the Energy Policy Act of 2005, FERC updated its definition of UTO to include the concept of productive and beneficial use for new CHP facilities. In addition to the definition of UTO in 18 CFR 292.202 (h)[5/] for which FERC requires detailed system information,18 CFR 292.205 (d)(1), which sets forth the criteria for a new qualifying cogeneration facility, now includes the requirement that "[t]he thermal energy output of the cogeneration facility is used in a productive and beneficial manner."

In the draft regulation, useful thermal output is defined in section 95102 (a) as:

> the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

As written, this definition could be interpreted to allow waste heat to be reported as useful, although PG&E understands that this was not ARB's intent. Therefore, the definition should be

5/ "Useful thermal energy output of a topping-cycle cogeneration facility means the thermal energy: (1) that is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water); (2) that is used in a heating application (e.g., space heating, domestic hot water heating); or (3) that is used in a space cooling application (i.e., thermal energy used by an absorption chiller)."

modified for consistency with other state and federal policies to capture the intent of reporting UTO used in a productive and beneficial manner. PG&E recommends modifying section 95102 (a) based on the language in 18 CFR 292.205 (d)(1), to read:

> the thermal energy output of the cogeneration facility used in a productive and beneficial manner in (1) an industrial or commercial process (net of any heat contained in condensate return and/or makeup water); (2) a heating application (e.g., space heating, domestic hot water heating); or (3) a space cooling application (i.e., thermal energy used by an absorption chiller).

As an alternative to the proposed definition above, ARB could adopt the UTO definition in 18 CFR 292.202 (h), which facilities would have to support with the requirements in section 131.80 FERC Form No. 556, and modify section 95112 (b) to contain the requirement in 18 CFR 292.205 (d)(1).

In summary, PG&E recommends that ARB make its UTO definition consistent with other federal policies by specifying that the UTO reported is only that which is used in a productive and beneficial manner.

SECTION 95112 (a). CALIFORNIA ENERGY COMISSION ("CEC") AND UNITED STATES ENERGY INFORMATION ADMINISTRATION ("EIA") IDENTIFICATION NUMBERS SHOULD BE REQUIRED.

PG&E suggests that all facilities be required to include identification numbers used for reporting to other agencies, specifically CEC and EIA identification numbers. PG&E and the other California investor-owned utilities have agreed to include these numbers as part of the CHP settlement, so that facilities can be correctly identified among different databases. Adding this requirement in section 95112 (a) would enable all parties and the ARB to compare reporting by facilities to various agencies.

SECTION 95112 (b). ADDITIONAL REFINEMENTS ARE NEEDED FOR COMBINED HEAT AND POWER.

UTO Sales. ARB should require CHP facilities to report how much steam is used onsite and to whom steam is delivered. Under the current regulation, facilities report steam purchases. Steam sales by recipient are also needed, especially since the proposed cap-and-trade regulation indicates that allowances will be allocated based on steam used onsite. CHPs that apply for qualifying facility status must report to FERC "the entity (i.e., thermal host) which will purchase the useful thermal energy output from the facility" and "whether the entity uses such output for the purpose of space and water hearing, space cooling, and/or process use" (FERC Form No. 556, section 131.80). Adding the requirement to report steam sent to the thermal host would align the reporting regulation with the cap-and-trade regulation and would also allow ARB to match reported steam purchases with reported steam sales. Since this is an existing business practice required by FERC, this reporting requirement will not impose any new burden on reporting entities.

UTO Metering. PG&E understands that ARB will need to supplement any UTO reported with requirements on metering of UTO. PG&E is not prepared to make recommendations on Btu metering specifics in these comments, but does believe that Btu meter standards are needed. At a minimum, facilities should also report whether the thermal output is in a closed loop or whether steam can be dumped to a non-useful load sink, like a cooling tower or radiator. Facilities could provide to verifiers schematics of the CHP system design to show the location of Btu meters and potential thermal dumps. For the purpose of providing further background on this issue, following is information on how various proceedings are dealing with this issue:

First, the California Solar Initiative lists Btu meter specifications for projects qualifying for its performance based incentive as follows:

- Provides totalizing outputs in Btus per period
- Capable of remote communications
- Monthly totalizing accuracy of ≤ 5%
- Flow meter and temperature sensor accuracy is National Institute of Standards and Technology (NIST) traceable.

Second, in their "monitoring and Data Collection Protocol for AB 1613 qualifying CHP facilities, the CEC requires a protocol that includes at least the following:

1. Instrumentation Diagram/Data Collection Point Diagram for the CHP System and the Connected Thermal Load. Identify the physical or chemical properties being measured, the instrument Manufacturer and Model Number.

2. Data Collection Plan, with data collection at least every 15 minutes, summed to daily and then monthly tabulations. Only the monthly data is reported, but the Energy Commission must have access to the more frequent data recording records.

Third, the California Public Utilities Commission ("CPUC") staff has suggested that CHP facilities receiving Self Generation Incentive Program ("SGIP") incentives be required to install metering. These facilities will be very small and likely under the reporting threshold, so metering requirements for SGIP should be much less sophisticated than requirements for CHP meeting the reporting threshold. Staff has not yet suggested specific protocols but plans to hold a public workshop to establish specific protocols to govern the metering and data reporting requirements for SGIP systems.[6/]

6/ Self Generation Incentive Program Staff Proposal, September 2010. http://docs.cpuc.ca.gov/efile/RULINGS/124214.pdf.

SECTION 95122. SMALL QUANTITIES OF NON-PIPELINE QUALITY GAS SHOULD BE AUTHORIZED TO USE DEFAULT EMISSION FACTORS FOR CO_2 CALCULATIONS AND BE EXEMPT FROM MONTHLY CARBON CONTENT CALCULATIONS.

Section 95122 (b)(2) requires local distribution companies ("LDCs") to estimate CO_2 emissions for natural gas that does not meet pipeline quality standards as defined in the regulations "using the Tier 3 methodologies specified in 40 CFR §98.33(a)(3)(iii) with monthly carbon content samples used to calculate the annual carbon content as specified in 40 CFR §98.33(a)(2)(ii)(A)." PG&E suggests that this language be modified to allow small quantities of California production that fall outside the pipeline quality definition to instead calculate CO_2 emissions using the default emission factor from Table NN-1 of 40 CFR Part 98 in contrast to monthly carbon content sampling. Small quantities will not materially affect the accuracy of the GHG calculation, and the need for monthly sampling could cause this gas to become significantly more expensive. In the last year, PG&E accepted 6,441,655 MMBtu of gas that did not meet the specification for pipeline quality gas. This gas came from 33 sources ranging in volume from 830 Dth to just over 2 million Dth, representing just 0.74% of the gas supplied to the PG&E system. If there were a 20% difference between the default emission factor and the factor calculated using the carbon content, the total difference would be only 0.15%. Therefore, sources providing less than 3 million Dth per year should be allowed to use the default emission factor for calculating CO_2 emissions and be exempt from the monthly carbon content calculation requirement.

SECTION 95122. ARB SHOULD CLARIFY THE REPORTING REQUIREMENTS FOR BIOFUELS.

Several subsections within section 95122 require LDCs to report the end-use CO_2 emissions from the combustion or oxidation of biomass-derived fuels (see subsections (a)(2), (b)(4), (d)(2)(C), and (d)(2)(F)). However, unless the biofuel were actually purchased by an LDC, there is no way for an LDC to know the volume of these biofuels on its distribution system. Staff's ISOR notes that a certification program similar to the Renewable Energy Certificate program under the Renewable Electricity Standard regulation would be an ideal solution to track emissions from biomass-derived fuels.[7/] However, even such a certification program would only track that fuel when ownership of it is transferred or sold. In the case of an LDC such as PG&E that may distribute pipeline-quality biomethane on its system, PG&E would have no way of knowing, for example, if biomethane were put into a pipeline in Texas and delivered to a facility in Oregon, nor would it know if that biomethane were delivered to a non-core[8/] customer in its own service territory. Therefore, PG&E recommends that this section be clarified to state that

7/ ARB Staff ISOR p. 37 and p. 88.

8/ NONCORE END-USE CUSTOMER: Noncore End-Use Customers are typically large commercial, industrial, cogeneration, wholesale or electric generation Customers who meet the usage requirements for service under a noncore rate schedule and who have executed a Natural Gas Service Agreement. Electric Generation, Enhanced Oil Recovery, Cogeneration, and Refinery Customers with historical or potential annual use exceeding 250,000 therms per year or rated generation capacity of five hundred kilowatts (500 kW) or larger, are permanently classified as Noncore End-Use Customers. See PG&E Gas Rule #1, http://www.pge.com/tariffs/tm2/pdf/GAS_RULES_1.pdf.

LDCs are only required to report the emissions from biomass-derived fuels *purchased by the LDC*.

SECTION 95122. NATURAL GAS LDC EMISSIONS CALCULATIONS SHOULD BE ALIGNED WITH FEDERAL REGULATIONS.

Section 95122 (b)(2) sets forth the following equation for natural gas LDCs to calculate total CO_2 emissions at the state border or city gate:

$$CO_2 = \Sigma CO_{2i} - \Sigma CO_{2l}$$

Where:
CO_2 = Total emissions
CO_{2i} = Emissions from natural gas received at the state border or city gate
CO_{2l} = Emissions from storage and direct deliveries from producers

For the purpose of this section, a public utility gas corporation may use the California border as the city gate.

ARB's above equation differs from the EPA's equation for the total CO_2 emissions from an LDC's supply of natural gas to end-users (as specified in Equation NN-6 from 40 CFR 98, Subpart NN) in that ARB does not require natural gas LDCs to subtract the emissions associated with gas delivered to end-users that use at least 460,000 Mscf per year (i.e. end-users who will be directly regulated in California's cap-and-trade program), gas delivered to transmission pipelines or other LDCs, or gas that is liquefied. Specifically, Equation NN-6 reads:

$$CO_2 = \Sigma CO_{2i} - \Sigma CO_{2j} - \Sigma CO_{2k} - \Sigma CO_{2l} \quad \text{(Eq. NN-6)}$$

Where:
CO_2 = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC customers not covered in paragraph (b)(2) of this section (metric tons).
CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received at the city gate as calculated in paragraph (a)(1) or (a)(2) of this section (metric tons).
CO_{2j} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).
CO_{2k} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year as calculated in paragraph (b)(2) of this section (metric tons).
CO_{2l} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received by the LDC and liquefied and/or stored but not used for

> deliveries within the reported year as calculated in paragraph (b)(3) of this section (metric tons).

PG&E understands that ARB intends to subtract directly regulated natural gas end-users' emissions from the gas received at the state border or city gate for PG&E via the mandatory reporting tool after PG&E's data has been submitted. However, PG&E still needs to identify those emissions as well as the other emissions specified in Equation NN-6 to ensure that its cap-and-trade compliance costs are not passed on to directly regulated end users. For example, PG&E has multiple deliveries to Southwest Gas Taps, multiple full time and emergency connections to SoCal Gas Company, direct deliveries to SoCal Gas Company billing meters, occasional flows to Chevron through a pipeline where they have a partial ownership interest, and deliveries to interstate pipelines operating in California. Because of the complex transactions involved in fully accounting for PG&E's compliance obligation, PG&E recommends that ARB allow LDCs to use Equation NN-6. Since PG&E will use Equation NN-6 for federal reporting purposes, using the same calculation for California reporting will support full reconciliation between EPA and ARB reporting, as well as reconciliation between ARB and PG&E data, as PG&E and ARB data on regulated end-users' emissions can be cross-referenced after the data is submitted.

In addition, to be consistent with ARB's exemption of pipeline-quality biomethane from a cap-and-trade compliance obligation in section 95852.2 (e) of the proposed cap-and-trade regulation,[9/] PG&E recommends that the emissions from biomethane purchased by a natural gas LDC be subtracted from its total CO_2 emissions at the state border or city gate. In the future, as ARB develops a process for LDCs to track the end-use CO_2 emissions from biomethane on their distribution systems, these emissions should also be subtracted from an LDC's total CO_2 emissions at the state border or city gate.

If ARB does allow LDCs to use Equation NN-6, PG&E suggests that the timeline for reporting be adjusted such that LDCs would provide a preliminary GHG emissions report to ARB by April 1. The ARB would then respond to LDCs by May 1 and provide a list of directly regulated entities with their LDC account numbers and fuel use. LDCs would then cross reference the fuel use and make sure that the directly regulated entities in their service territories are subtracted out of the LDC's compliance obligation. LDCs would then send a final report to ARB by June 1. This process allows the period between May 1 and June 1 to be used to reconcile differences between the ARB and LDC lists of directly regulated entities.

SUBARTICLE 5. ARB SHOULD CONFORM ITS REGULATIONS WITH THE FINAL EPA SUBPART W.

With the November 8, 2010, issuance of EPA's final reporting requirements for Subpart W, 40 CFR Part 98, PG&E recommends that ARB conform Subarticle 5 to the final version of the

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9/ ARB. Appendix A, Proposed Regulation Order, California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Page A-66.

federal requirements to the greatest extent possible to maximize the consistency between these two mandatory reporting regulations. The final version of Subpart W reconciled a wide range of issues from several industry segments, so the ARB's incorporation of Subpart W would serve to reflect those critical changes.

SECTION 95150. ARB SHOULD CONFORM TO SUBPART W'S SOURCE CATEGORY DEFINITIONS, BUT CLARIFY NATURAL GAS DISTRIBUTION TO REFLECT CALIFORNIA-SPECIFIC CONDITIONS.

EPA revised Subpart W (specifically §98.230) to clarify the source categories in the rule. PG&E recommends that ARB adopt these definitions to be consistent with the federal rule because PG&E has several concerns with ARB's proposed revised definitions, which are in large part based on EPA's previous draft definitions.

In particular, EPA's final definition of natural gas distribution (§98.230 (8)) clarifies that customer meters and infrastructure and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and "farm taps" upstream of the LDC, are excluded from the natural gas distribution industry segment. While these sources are excluded from reporting, EPA notes that its final definition for natural gas distribution will still result in 90 percent GHG emissions coverage of this industry segment.[10/] Since ARB's reporting threshold is lower than EPA's, the vast majority of the emissions from this industry segment will be captured.

EPA's final definition of natural gas distribution still needs to be further clarified to identify the specific assets from which emissions should be reported. Specifically, EPA requires emissions reporting from natural gas distribution emission sources that are operated by an LDC that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. Since the California LDCs (as well as several other utilities) operate both transmission and distribution systems (and storage systems), clarification is needed to distinguish between distribution facilities and other facilities. Specifically, the definition of a distribution pipeline should be based on physical attributes such as a Maximum Allowable Operating Pressure (MAOP) of 60 psig or lower, with MAOP as defined in EPA 49 CFR.

The PG&E distribution and transmission systems are regulated by the CPUC, which also sets the rates for distribution and transmission systems, in two separate proceedings. Rates for the transmission system are set under a proceeding called the Gas Transmission and Storage rate case, and rates for the distribution system are set under the General Rate Case proceeding. Both of these proceedings differentiate distribution and transmission facilities based on MAOP. Facilities with an MAOP above 60 psi are considered transmission, and those with an MAOP of 60 psi or less are considered to be distribution. As such, PG&E proposes to use the 60 psi MAOP to differentiate between distribution and transmission facilities.

10/ EPA 40 CFR Part 98. Mandatory Reporting of Greenhouse Gases – Petroleum and Natural Gas Systems, EPA-HQ-OAR-2009-0923; FRL-], RIN 2060-AP99, p. 44.

SECTION 95152. ARB SHOULD ADOPT THE DEFINITION FOR METERING AND REGULATING STATIONS IN SUBPART W.

Section 95152 (i)(1) and 95152 (i)(2) use the undefined terms "above ground meter regulators and gate station" and "below ground meter regulators and vault," which could be interpreted to include not only city gates and large custody transfer or district metering and regulating (M&R) stations but also industrial, commercial and even residential customer regulating and metering equipment. We do not believe this was ARB's intent, but unless the term is clarified and made consistent with the final EPA rule, regulatory uncertainty and the risk of varying interpretations by field enforcement personnel could result in LDCs including all customer meters in their leak surveys and reporting. When multiplied by PG&E's 4.3 million customer meters across California, each annual leak survey would result in significant costs to the company and its customers. Therefore, PG&E urges ARB to adopt EPA's definition as modified in the preceding paragraphs to be consistent with the federal rule and to more clearly define the metering and regulation equipment on the distribution system of California LDCs.

SECTION 95153. ARB SHOULD ALLOW BEST AVAILABLE MONITORING METHODS FOR 2011 REPORTING AS PERMITTED IN SUBPART W.

The final Subpart W (specifically §98.234 (f)) allows the use of best available monitoring methods ("BAMM") for specified time periods and for certain emissions sources during the 2011 data collection year. With the recent release of the revised reporting regulation and December 2010 consideration by the Board, it is essential to allow the optional use of BAMM during 2011. There are many facilities covered by this rule that should be allowed to use BAMM for parameters for which it is not reasonably feasible to acquire, install, or operate a required piece of monitoring equipment in a facility, or to procure measurement services from necessary providers. Complying entities should be granted a reasonable period of time to adjust their operations and industry practices to the requirements of the final rule. This is critical, for example, for monitoring of vented emissions at compressor stations. ARB's revised rules requires logging of all blowdown events starting January 1, 2011; PG&E will not have enough time to put the systems in place to record these events by then, nor does it have the staff to manually record them. Allowing the optional use of BAMM during 2011 as permitted by Subpart W would provide reporting entities the time necessary to comply with the final rule.

SECTION 95153. ARB SHOULD ADOPT EPA'S LEAK DETECTION METHODS AND REQUIREMENTS.

The final Subpart W (specifically §98.234 (a)) allows leak detection surveys using one of the three following methods:

- An optical gas imaging instrument.
- An infrared laser beam illuminated instrument.
- Method 21.

In addition, for natural gas distribution, the final Subpart W only requires leak detection for above ground M&R stations (i.e. city gate stations) at which custody transfer occurs. ARB's current requirement to annually survey all above-grade M&R station components using an optical gas imaging instrument, which is based on the previous draft Subpart W, is inconsistent with the final rule and does not use industry standard practices to detect leaks. The other methods allowed by EPA are more widely used by the industry to detect leaking equipment and are far more cost effective. For example, PG&E has demonstrated that Organic Vapor Analyzers, generally permitted under Method 21, are a proven technology for which extensive operating procedures and trained employees already exist. PG&E, as a member of the American Gas Association, is working to gain clarification from EPA that the specific standard practices that PG&E uses are acceptable under EPA's final rule. For these reasons, and to ensure consistency between reporting rules, PG&E urges ARB to adopt EPA's leak detection methods and requirements.

SECTION 95153. ARB SHOULD EXEMPT METERING REQUIREMENT FOR PNEUMATIC DEVICES ON CRITICAL SAFETY SYSTEMS.

PG&E believes that ARB should exempt critical safety systems from pneumatic device metering requirements in § 95153 (a) when the installation of metering devices on pneumatic controls could impact the reliability and functionality of the system. Typical critical safety systems on the PG&E gas system include pressure regulation and over-pressure protection devices, and valves used for the emergency isolation and/or evacuation of stations or pipeline segments. PG&E's primary concern is that by adding meters to these systems, an additional point of failure is introduced, which could reduce the reliability of critical safety systems.

SECTION 95153. ARB SHOULD CONFORM WITH EPA'S BLOWDOWN VENT STACK EMISSION CALCULATION METHODOLOGY.

For section 95153 (h), ARB should adopt the requirements for blowdown vent stacks of EPA Subpart W as noted in EPA 40 CFR 98.233(i), which specifies that blowdown volumes smaller than 50 standard cubic feet are exempt from reporting. The resources necessary to log the required information for these small blowdowns are not appropriate in light of the small volume of emissions from these sources.

SECTION 95153. ARB SHOULD CONFORM WITH EPA'S METER ACCURACY REQUIREMENTS.

Section 95153 (n)(2)(B) concerning reciprocating compressor rod packing venting does not specify the accuracy requirements of temporary meters. PG&E suggests that ARB adopt EPA's requirements for calibration accuracy in 40 CFR 98.3(i), which provide facility operators and verifiers clear guidelines for meter accuracy.

SECTION 95156. ARB SHOULD ELIMINATE THE NEED TO REPORT COMPRESSOR THROUGHPUT OR ALLOW THE USE OF AVAILABLE METRICS.

Section 95156 (c)(18) states:

> (18) For reciprocating compressor rod packing, the operator must report the following per rod packing:
>
> (A) Total throughput of the reciprocating compressor whose rod packing emissions is being reported.

Compressor throughput is not used in the process of calculating emissions, and metering individual compressor flow is often very difficult. In many cases, there is insufficient clear space for an accurate meter, and the compressor vibrations and pulsations significantly affect the ability to achieve accurate metering results. Operating hours are already reported and can be used to approximate the compressor throughput. PG&E recommends that ARB clarify that it is acceptable to estimate throughput using available metrics such as operating hours.

ARB SHOULD EXEMPT BIOMASS-DERIVED FUELS FROM DIGESTER PROJECTS FROM A COMPLIANCE OBLIGATION IN THE CAP-AND-TRADE PROGRAM.

The "Greenhouse Gas Verification Requirements" section of ARB's Staff Report on Mandatory Reporting states that "Any biomass-derived biofuels can not also receive an offset credit in another voluntary or mandatory program and still be an eligible biomass-derived fuel for reporting as biomass CO_2 that would not be subject to an obligation in the cap-and-trade program."[11/]

PG&E interprets this to mean that, for example, a livestock manure digester project (e.g. a dairy) that generated and sold offsets and combusted the biogas from that project either as a flare (i.e. stationary combustion) or as a self-generator of electricity would have a cap-and-trade compliance obligation for those combustion emissions if they were equal to or greater than 25,000 MT CO_2e.

PG&E contends that biomass-derived fuel should not be subject to a cap-and-trade compliance obligation if it comes from a project that also receives offset credits, for the following reasons:

11/ California Air Resources Board. 2010. *Staff Report: Initial Statement Of Reasons For Rulemaking. Revisions To The Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant To The California Global Warming Solutions Act of 2006 (Assembly Bill 32)*. Page 88. http://www.arb.ca.gov/regact/2010/ghg2010/ghgisor.pdf.

A. It Is Inconsistent With The ARB's Compliance Offset Livestock Manure (Digester) Project Protocol.

Offsets from livestock manure digester projects, such as those that comply with the ARB Compliance Offset Livestock Manure (Digester) Project Protocol, are from the net change in emissions associated with installing a biogas control system ("BCS") at the project's facility. As noted on page 6 and reiterated in Table 4.1 on page 9 of the Protocol, the CO_2 emissions associated with the generation and destruction of biogas (such as through flaring, electricity generation, or combustion as pipeline gas or CNG/LNG) are considered biogenic and are not included in a project's GHG Assessment Boundary.[12/] The protocol specifically notes that the CO_2 emissions from combustion of the biogas through flaring, during electric generation, or by an end user of pipeline or CNG/LNG, are excluded from the project's emissions.[13/]

B. It Is Inconsistent With Approaches Taken By The Intergovernmental Panel On Climate Change ("IPCC"), U.S. EPA, And Department Of Energy ("DOE").

Both the IPCC guidelines for CO_2 emissions from BCS[14/] and the EPA in its Mandatory Reporting of GHG Rule[15/] agree that the CO_2 emission are biogenic (as opposed to anthropogenic) and should not be counted towards a facility's GHG emissions, and, are therefore not subject to a compliance obligation. The IPCC Guidelines for National Greenhouse Gas Inventories states that "only fossil CO_2 should be included in national emissions under Energy Sector while biogenic CO_2 should be reported as an information item also in the Energy Sector."[16/] IPCC reasons that "CO_2 emissions from livestock are not estimated because annual net CO_2 emissions are assumed to be zero – the CO_2 photosynthesized by plants is returned to the atmosphere as respired CO_2." EPA's Inventory of U.S. GHG Emissions and Sinks specifically states that biomass combustion emissions of "biogenic origin" are excluded because "Fuels with biogenic origins are assumed to result in no net CO_2 emissions, and must be subtracted from fuel consumption estimates."[17/] Finally, DOE's voluntary GHG reporting program, 1605(b), states that "carbon dioxide emissions of biogenic fuels do not "count" as

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12/ California Air Resources Board. 2010. *Compliance Offset Protocol, Livestock Manure (Digester) Projects*. Page 6.

13/ California Air Resources Board. 2010. *Compliance Offset Protocol, Livestock Manure (Digester) Projects*. Page 6. Table 4.1. Description of all Sources, Sinks, and Reservoirs, page 9.

14/ Intergovernmental Panel on Climate Change. 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Volume 4, Page 10.7.

15/ U.S. Environmental Protection Agency. 2009. *Mandatory Reporting of Greenhouse Gases; Final Rule.* http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-Full%20Version.pdf.

16/ Intergovernmental Panel on Climate Change. 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Volume 5, Page 5.5.

17/ U.S. Environmental Protection Agency. 2010. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008*. Chapter 3. Page 3-17. http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Chapter3-Energy.pdf.

anthropogenic emissions under the Framework Convention on Climate Change because the carbon embedded in biogenic fuels is presumed to form part of the natural carbon cycle."[18/]

C. Without The Benefit Of Both Energy And Carbon Offsets Livestock Manure Digester Projects Are Not Cost Effective.

Even with full credit for carbon offsets and use of the project's biogas for self-generation or sold electricity, Livestock Manure Digester Projects are financially challenging. Although, ARB currently lists nineteen digester projects as operational,[19/] there are only eleven digester projects currently in operation in California. Many digesters have shut down for economic and/or operational reasons. In order for these projects to contribute to the State's GHG reduction goals, they need revenue from both the energy value of the biogas and carbon offsets. Finally, if these projects don't get built, there will be an increase in greenhouse gas emissions.

ARB SHOULD CLARIFY THE ROLE OF OUT-OF-STATE RENEWABLE ENERGY PURCHASES IN CALIFORNIA'S CAP-AND-TRADE PROGRAM.

As noted in PG&E's comments on the Cap-and-Trade regulation, PG&E strongly believes that ABR should provide that resources eligible under the RES or RPS are credited as zero GHG to ensure that the RES, RPS, Cap-and-Trade and Mandatory Reporting Regulations ("MRR") are consistent and achieve GHG reductions in the most cost effective manner possible. ARB need not, and appropriately should not, follow a widely disfavored recommendation of the Western Climate Initiative ("WCI") on this issue that would result in the State not realizing the full GHG-reduction benefits of the RES and RPS programs.

As such, PG&E recommends that the proposed amendments to the MRR be revised to provide that imported Renewable Energy Credits ("RECs") include the renewable-GHG attribute of the out-of-state renewable facility from which it was generated. This approach is necessary to ensure that California receives the full GHG-reduction benefits of the State's renewable programs and is consistent with the statutory and CPUC definitions of a REC and the numerous CPUC-approved RPS contracts that have been entered into on behalf of utility customers. An approach that does not allow the GHG attributes from these RPS contracts to be recognized is contrary to the RPS legislation and would arbitrarily increase costs for California customers. It also calls into question ARB's use of AB 32 as statutory authority to require 33% renewables as a GHG-reduction measure, and could result in the State not achieving ARB's forecast GHG reductions from both the 20% and 33% renewable programs. PG&E offers the following further considerations related to this issue below.

18/ Department of Energy. 2007. *Technical Guidelines – Voluntary Reporting of Greenhouse Gases (1605(b)) Program*. Page 51. http://www.eia.doe.gov/oiaf/1605/January2007_1605bTechnicalGuidelines.pdf.

19/ California Air Resources Board. 2010. *Manure Digesters in California*. http://www.arb.ca.gov/ag/manuremgmt/operating-manure-digester-site-list-4th-quarter-2010.pdf.

A. The MRR Should Be Revised To Provide That Imported RECs Include The Renewable-GHG-Attribute Of The Out-Of-State Renewable Facility From Which It Was Generated.

In the ARB Staff Report: Initial Statement of Reasons for Rulemaking, staff states that RECs cannot be used in GHG reporting (ISOR, pg 48). For the reasons provided below, PG&E recommends that the MRR be modified to provide that imported RECs include the renewable-GHG attribute of the out-of-state renewable facility from which it was generated.

1. RECs And WREGIS Certificates Contain The GHG Attribute Of The Renewable Resource.

Pursuant to SB 107 (Chap. 464, Stats of 2006), RPS RECs convey the environmental benefits of renewable generation. SB 107 defines a REC as "a certificate of proof, issued through the accounting system established by the Energy Commission pursuant to Section 399.13, that one unit of electricity was generated and delivered by an eligible renewable energy resource," which includes:

> all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.[20/]

Consistent with SB107 in Decision 08-08-028, the CPUC held that an RPS-eligible REC includes:

> <u>*...all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource*</u>, including any avoided emission of pollutants to the air, soil or water; any avoided emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, or any other greenhouse gases that … contribute to the actual or potential threat of global climate change; [FN 77] and the reporting rights to these avoided emissions, such as Green Tag reporting rights. [FN78]

The system set up by the CEC for tracking and verifying RECs is the Western Renewable Energy Generation Information System ("WREGIS"). A WREGIS Certificate (as defined in the WREGIS Operating Rules) "represents all Renewable and Environmental Attributes from one MWh of electricity generation from a renewable energy Generating Unit" where the definition of *Renewable and Environmental Attributes* is "Any and all credits, benefits, emissions reductions,

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20/ Pub. Util. Code § 399.12(f) (emphasis added).

offsets and allowances, howsoever entitled, attributable to the generation from the Generating Unit, and its avoided emission of pollutants."[21/]

The ARB's recently adopted RES also relies on the WREGIS system to track, quantify, and verify renewable energy purchases. The RES provides for the use of unlimited WREGIS-certified resources with no delivery requirement. ARB did this after careful consideration of the impact on GHG reduction, concluding in its staff report that, "*…allowing the use of unbundled RECs, regardless of where they are generated in the WECC, will reduce GHG emissions by the same amount as a more limited approach." (RES Staff Report, Recommendation ES-15.)*

Therefore, PG&E recommends that the MRR not arbitrarily and contrary to statute adopt a different definition of a REC or any other instrument used to comply with 33% RES that does not include all of the environmental attributes of the renewable generation.

2. PG&E's Proposed Modifications Would Allow California To Retain The GHG Reduction Benefits Of RPS Eligible Purchases And Avoid Subjecting California Customers To Higher Costs For Renewables.

Stripping the GHG attributes from the imported RECs would also deprive California of the full GHG reduction benefits of the State's renewable programs and unnecessarily increase the cost of renewables for customers in various ways. Consistent with the statutory and CPUC-adopted definitions of a REC, the utilities' RPS contracts provide that the REC includes all renewable and environmental attributes of the renewable energy resource (with certain limited and specified exceptions). Thus by law and by contract, when a REC is unbundled from the renewable output, the zero-GHG attribute of the renewable resource stays with the REC, and the owners of the remaining null power may not claim the GHG-emission-reduction attribute of the renewable resource.

If the utilities are not allowed to claim the GHG attributes of the imported RECs through bundling the WREGIS Certificate with energy imports, these RPS- and RES-eligible contracts will not count toward decreasing the State's GHG emissions. This conflicts with the stated policy objective of both the RPS and RES to achieve GHG reductions and means that ARB's forecast of GHG reductions from the RPS and RES are not likely to be achieved.

The approach taken in the proposed regulation would increase the cost of renewables for California customers. For example, utility customers purchasing variable renewable energy under a firming-and-shaping arrangement are paying for the GHG attributes of the underlying renewable facility, per the definitions stated above. Pursuant to the RPS rules, the RECs from the variable renewable energy resource are matched with imported energy that can be scheduled into the CAISO. If this imported energy is assigned system emissions, California customers will

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21/ WREGIS Certificate Definition Modification http://www.wregis.org/uploads/files/106/WREGIS%20Certificate%20Definition%20modification_FINAL%2012%208%2008.pdf.

have to pay twice – first for the REC that already contains the zero-GHG attribute and then for an allowance for the system emissions. Given that the renewable programs are already identified as the highest cost GHG reduction program measures, ARB should not adopt regulations that force these costs higher.

In addition, not only would it increase the cost of renewables, this approach could increase costs for the entire cap-and-trade program. The ARB estimate of AB 32 costs to customers is predicated on the 20% RPS and 33% RES decreasing GHG emissions. In ARB's Compliance Pathway Analysis, staff estimates that the RES program will reduce emissions by 11.4 MMT.[22/] In Scenario 3, where the complementary policies achieve 15 MMT less than in Scenario 1, allowance prices jump from $20/metric ton to $40/metric ton. As this analysis illustrates, the allowance price and the overall cost of the cap-and-trade program could significantly increase if the eligible purchases under the RPS and RES programs, including already executed contracts, are not fully credited as reducing GHG emissions.

3. The MRR Should Not Ignore That Renewable Generation Is Tracked Through WREGIS And RECs, Not Contracts With Null Power

WREGIS is an independent, renewable energy tracking system created expressly to validate claims on renewable electricity and prevent double counting. WREGIS does this by creating RECs for each MWh of generation. Entities claim ownership of the renewable generation through ownership of the REC. In California, RECs must currently be associated with delivered electricity to count for compliance with the RPS program.[23/] WREGIS can match RECs with a NERC E-tag documenting the energy import. Tracking through WREGIS can ensure that a REC created outside of the WCI could be used to assign a zero emissions rate to the imported power once the REC has been delivered with the energy import into the WCI. This means that the electricity import that has been matched with a REC should receive the renewable facility's emissions treatment.

On the other hand, WCI's chosen approach of tracking the GHG attribute through contracts (Option 3) is not feasible.[24/] This approach would require an unworkable verification process, which adds unnecessary restrictions and complications to procuring renewable generation. PG&E further questions whether Option 3 can be implemented given that the legally required definition of a REC included in the contracts provides that the GHG attribute has been transferred to the buyer of the REC. Therefore, the GHG attribute cannot remain with the null power, as would be required in Option 3. ARB should instead adopt the other approach that was

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22/ Based on the Compliance Pathways Analysis in the GHG Cap-and-Trade ISOR.

23/ Public Utilities Code Section 399.16 (a) (3) which establishes conditions for authorizing RECs for RPS compliance requires that the underlying electricity from which the REC is created is delivered for consumption in California.

24/ WCI released a discussion paper that included three options to prevent double counting of non-WCI renewable power. In written comments to the WCI, the majority of parties supported using RECs to claim the zero-GHG-attribute of the renewable resource (Option 2 in the WCI discussion paper) and nearly unanimously opposed using contracts with the null power to do so (Option 3).

considered in the WCI discussions (Option 2), which received nearly unanimous stakeholder support. This approach addressed how to tie electricity imports into the WCI back to a renewable generator when the actual electricity from the facility cannot be imported using the already existing system of RECs tracked in WREGIS.

B. The MRR Should Not Take A Step Backward From The Treatment Of Firmed-And-Shaped Imports From Renewable Facilities Contained In The December 2007 MRR.

The existing reporting rules allow the energy importer to claim the zero-GHG attribute of a variable renewable resource when the energy is delivered to California under a firming-and-shaping arrangement. The amendments to the MRR take a step backwards from this approach and may not allow California customers to realize the GHG benefits of these renewable energy purchases, which will increase customer costs.

Electricity from some renewable resources cannot be directly imported into California. Electricity sales from one area to another are generally required to maintain a constant power level over each hour. Power from variable energy resources, such as wind or solar plants, fluctuates, and therefore cannot be imported directly. The RPS statute authorizes the use of firming–and-shaping transactions to accommodate the purchase of out-of-state variable energy resources. Consistent with the statute, the CEC has enumerated several types of transactions that involve firming and shaping, and determined that these kinds of transactions are RPS-eligible.[25/] Additionally, the CPUC has approved various transactions involving firming and shaping for RPS compliance.

In the December 2007 MRR, the ARB allows for importers to claim the GHG attribute of the renewable resource when the energy is delivered to California under a firming-and-shaping arrangement via the following definition and guidance:

> A specified source means a particular generating unit or facility for which electricity generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract. California eligible renewable resources are considered specified sources.[26/]
>
> From the ARB guidance: "When entities have contracts with renewable energy resources that require firming power to back up the contracts, the entity reports the total amount of renewable power generated for the contract over the report year as a specified source."[27/]

The Proposed MRR Amendments change this text.

25/ CEC RPS *Eligibility Handbook* (CEC-300-2007-006-ED3-CMF) at 23-24, n. 21.
26/ Title 17, California Code of Regulations, Section 95102 (a)(180).
27/ December 2008 Instructional Guidance for Mandatory GHG Emissions Reporting, Section 8.3.4 (Guidance for Regulation Section 95111).

The amendments to Section 95111 (g) (7) include the provision:

> Substitute electricity. Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section. Substitute electricity is provided under contract with specified facilities, not classified as variable renewable resources, to meet delivery requirements when the specified facility or unit is not operating.

PG&E seeks clarification regarding the intent of this language and recommends that at a minimum, the language in the MRR reflect the same intent as the December 2007 with respect to firming-and-shaping contracts. Even the December 2008 WCI Discussion Paper allowed for firming-and-shaping transactions, stating, "Note that Option 3 does not preclude the use of shaping and firming to efficiently transmit non-WCI renewable energy from its region of origin."

PG&E and the other IOUs have entered into numerous contracts for variable renewable energy under firming-and-shaping arrangements based on the existing regime that attributes zero GHG to the imported energy.[28/] If PG&E's customers are required to retire allowances for these RPS-eligible purchases, it would cost them millions of dollars per year above the premium they have already paid for zero-GHG energy. As set forth above, ARB should avoid this result and provide that if the contract purchases count towards the RES or RPS, it should be credited as zero GHG.

PG&E appreciates the opportunity to comment on the revised mandatory reporting regulation, and we look forward to continue working with the ARB and all concerned stakeholders to ensure the successful implementation of the cap-and-trade program.

Very truly yours,

/s/

Judi K. Mosley

JKM:kp

28/ The PUC is currently considering counting energy delivered via firming-and-shaping transactions toward an IOU's TREC usage limit. Regardless of the PUC's decision on the criteria for bundled RPS procurement transactions, the ARB needs to maintain language allowing utilities to report firming-and-shaping transactions as specified energy.