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December 2, 2010

E-Filing
ARB's Cap-and-Trade Website

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Assistant Executive Officer – Climate Change
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Pacific Gas and Electric Company's Comments on the Air Resources Board's October 28, 2010 Proposed Regulation to Implement the Cap-and-Trade Program under AB 32

Dear Dr. Kennedy:

Pacific Gas and Electric Company ("PG&E") is pleased to submit these comments on the Air Resources Board's ("ARB") proposed regulation entitled "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" and accompanying materials, released October 28, 2010 under Assembly Bill 32 ("AB 32"). PG&E will be submitting comments on the proposed amendments to the Mandatory Reporting Regulation under separate cover.

We believe a well-designed, multi-sector cap-and-trade program – linked with emerging regional, national, and international programs – will allow California to meet its greenhouse gas ("GHG") emission reduction goals in a cost-effective manner as required by AB 32 (Cal. Health & Safety Code, § 38560). We believe ARB has made significant progress with the design of the cap-and-trade program and recognize the significant effort put into this proposed regulation. We offer the following comments on specific program features which we believe could continue to be refined and will work constructively with ARB and all concerned stakeholders to ensure sustained GHG emission reductions, manage costs for our customers and create a program that can serve as a model for others to follow.

I. SUMMARY AND RECOMMENDATIONS.

A. PG&E Supports The Inclusion Of The Allowance Price Containment Reserve In The Cap-And-Trade Regulation And Recommends That ARB Monitor The Potential For Depletion Of Allowances.

B. PG&E Recommends That ARB Establish A Contingency Plan To Address Potential Allowance Price Containment Reserve Depletion

C. PG&E Supports ARB's Proposal To Allocate Allowances To The Electric Local Distribution Companies ("LDCs") For The Benefit Of Customers.

- PG&E recommends that the quantity of allowances allocated to the electric sector via utilities be adjusted to reflect grid deliveries from combined heat and power facilities.

- PG&E recommends that the ARB's allocation to electrical distribution utilities appropriately balance early action and managing utility customers' costs, and is administered in an equitable manner across all LDCs.

D. An Adequate Supply Of Offsets Is Necessary To Ensure That The Goals Of AB 32 Are Achieved In A Cost-Effective Manner.

- In the first compliance period, the supply of offsets is likely to be inadequate to cover 8% of emissions, as would be permitted under the proposed regulation. To address this situation, PG&E encourages the ARB to approve additional protocols, and proposes a simple method to allow the carryover of unfilled rights to use offsets.

- The record retention, conflict of interest requirements and re-verification of early action offsets will discourage offset project development. PG&E recommends modest changes to the recordkeeping requirements and encourages flexibility with conflict of interest requirements at the start of the market.

E. PG&E Requests Clarification Of The Role Of Out-Of-State Renewable Energy Purchases In California's Cap-And-Trade Program.

- PG&E recommends ARB provide that resources eligible under the Renewable Electricity Standard ("RES") or Renewable Portfolio Standard ("RPS") are credited as zero GHG to ensure that the RES, RPS, cap-and-trade, and Mandatory Reporting Regulations are consistent and achieve GHG reductions in the most cost-effective manner.

- As the Board looks to harmonize RES eligibility with CPUC guidance on RECs, it should ensure that the RES, RPS, cap-and-trade, and Mandatory

Reporting Regulations each provide the same cost-effective GHG-reduction benefits.

F. ARB Should Provide Additional Support For The Revised 2020 Allowance Budget.

- PG&E requests further clarification and examination of ARB's approach for setting the 2020 allowance budget and the revised emissions estimates associated with uncapped sectors.

G. Growth Resulting From Vehicle Electrification Should Be Accompanied By A Commensurate Allocation To Protect Utility Customers From Increased Compliance Costs.

- Because utility customers bear the cost of emissions associated with electric fuel, ARB should monitor the potential increase in vehicle, port, off-road equipment and goods movement electrification, and allocate allowances to the electric sector if use of electricity as a transportation fuel causes electricity demand to increase.

H. ARB Should Postpone Consideration of Allowance Allocation To Natural Gas Utilities For Customer Benefit To Allow For Thorough Evaluation.

I. Any Proposal To Remove Or Retire Allowances To Reflect Voluntary Renewables Should Preserve The Environmental Integrity Of AB 32 And Not Increase The Compliance Costs For Utility Customers And Other Participants.

- PG&E is concerned that a voluntary renewable set aside could raise costs for our customers if not properly designed and implemented. If the ARB proceeds with a set-aside, it should limit the quantity of allowances, and closely monitor the performance of projects that receive allowances.

J. ARB Should Provide Additional Detail On Auction Design In The Proposed Regulation.

- PG&E recommends that ARB include additional regulatory language further detailing the design and implementation of the cap-and-trade auction to ensure efficient market functioning.

K. The Allowance Holding Limit Should Not Be Applied to Regulated Utilities.

L. ARB Should Make Available a Greater Number of Future-Vintage Allowances To Help Complying Entities Manage Compliance Costs.

M. ARB Should Amend Its Rules To Be Consistent With The Three-Year Compliance Period.

N. ARB Should Clarify The Treatment Of Biogas, Biomass, And Natural Gas System Fugitive And Vented Emissions.

- PG&E recommends that ARB clarify that combustion emissions of biogas from digesters are exempt from compliance obligation.

- ARB should not separately regulate fugitive and vented emissions from natural gas systems, because the emission factors for fugitive and vented emissions from natural gas systems are imprecise and based on old data and the emissions from these sources are already captured indirectly through the compliance obligation of Natural Gas Suppliers.

O. ARB Should Enforce AB 32 In A Manner Which Is Reasonable And Consistent With Other Stationary Source Violations.

- ARB should revise the proposed cap-and-trade enforcement provisions to ensure that penalties are commensurate with the scope and severity of the violation and potential environmental harm, and do not inadvertently punish complying entities by creating artificial allowance shortages.

P. ARB Should Closely Monitor The Cap-And-Trade Program And Implementation Of The Scoping Plan To Ensure The State Meets AB 32 Emission Reduction Targets In A Cost-Effective Manner.

- ARB should include provisions in the cap-and-trade regulation establishing formal reviews of the regulation at least once each compliance period and provide specific criteria to consider in these reviews.

- ARB should also create an independent market monitoring board responsible for monitoring the market and auction on a quarterly basis and recommending corrective action if needed to the ARB and Governor.

- ARB should establish a more structured process and approach for evaluating the comparative cost-effectiveness of program measures as well as the relative cost-effectiveness of those measures vis-à-vis the cap-and-trade program.

II. DISCUSSION.

A. PG&E Supports The Inclusion Of The Allowance Price Containment Reserve In The Cap-And-Trade Regulation And Recommends That ARB Monitor The Potential For Depletion Of Allowances.

PG&E strongly supports the inclusion of a cost containment mechanism focused on allowance prices, with a ceiling price for accessing the Allowance Price Containment Reserve ("APCR") and a reserve price as part of the quarterly auction. PG&E believes that including such a mechanism is one of the highest priority issues in designing an effective cap-and-trade program because of the cost protection it offers from potentially unsustainably high and volatile allowance prices, while also ensuring market viability and reasonable incentives for low carbon investment.

PG&E acknowledges that there are a variety of ways to design an allowance reserve for cost containment purposes. PG&E appreciates Staff's consideration of the various alternatives and efforts to balance a number of objectives. PG&E supports ARB's decision to establish an allowance reserve filled with allowances made available for sale at specified prices during direct quarterly sales. Additionally, PG&E supports their general usage restrictions, such as limiting the ability to purchase from the reserve to complying entities, and requiring these entities to immediately retire any allowances purchased from the allowance reserve to their compliance accounts. Finally, PG&E supports ARB's decision to increase the offset limit to account for the allowances removed from the market to fill the allowance reserve. PG&E understands that the ARB intends to remove the restrictions in § 95913 (c)(1)(B) that entities must empty both their limited use holding accounts and general holding accounts before accessing the allowance reserve. PG&E supports removal of the restriction on the limited use holding account. PG&E recommends ARB defer resolution of the restriction associated with the general holding account until this issue can be resolved in the context of the overall auction design.

PG&E is concerned, however, that the ability of the allowance reserve to mitigate allowance price volatility could be compromised by a shortage in the supply of offsets, faster than expected economic growth, reduced efficacy of the complementary measures, and/or unforeseen events such as a prolonged drought or an extended outage of one of California's nuclear units. As a result, PG&E commissioned Charles River and Associates ("CRA") to analyze a range of scenarios in an effort to understand the circumstances under which the allowances in the reserve might become depleted. CRA analyzed the sufficiency of allowances in the containment reserve under different assumptions about economic activity (including economic growth, demand for electricity, and emissions growth in the non-electric sectors), offset supply, efficacy of complementary measures, and unforeseen events. Under ARB's business as usual forecast for economic activity, (including ARB's assumptions for offsets), CRA concluded that the quantity of allowances in the reserve was sufficient under a range of assumptions about the efficacy of complementary measures. However, under certain plausible circumstances the allowance reserve reached a critically low level or was depleted entirely. Specifically, under higher economic growth,[1/] reduced offset supply, and lower than expected efficacy of complementary measures the allowance reserve was depleted entirely. The allowance reserve was stressed further by unforeseen events such as a prolonged drought or an extended outage at one of California's nuclear units.[2/]

To ensure that the allowance reserve remains adequate over time, PG&E recommends that ARB establish a formal review process that would include monitoring the allowance market for potential market failures or unsustainably high allowance prices, and develop a contingency plan that could be implemented should the allowance reserve approach low levels. This review process, as discussed in greater detail in Section P, should include active monitoring of the allowance market as well as drivers that will have a strong impact on the allowance market (i.e., offset procurement, economic growth, penetration of low carbon technologies, efficacy of complementary measures, and unforeseen events, such as drought). Further discussion on the establishment of a contingency plan is provided below.

B. PG&E Recommends That ARB Establish A Contingency Plan To Address Potential Allowance Price Containment Reserve Depletion.

As discussed in Section A of PG&E's comments, CRA finds that under ARB's business-as-usual scenario, the quantity of allowances in the APCR is sufficient. However, under moderately high growth and adverse supply conditions, including higher-than-expected economic growth, a limited supply of offsets and reduced effectiveness of program measures, the APCR may be depleted.

Therefore PG&E recommends that ARB actively monitor the allowance market for the possible depletion of the reserve. In addition, PG&E recommends that ARB establish a plan that they would immediately implement in the event 50% of the allowances in the reserve have been purchased. PG&E's recommended plan is as follows:

1. Use revenue from the sale of reserve allowances to refill the reserve with Reducing Emissions from Deforestation and Forest Degradation ("REDD") offset credits[3/] and

2. Make available additional and adequate supply to the market in a timely manner from:

    a. An increase in the offset supply via an increased offset limit. To provide adequate supply for this increased limit, ARB should adopt additional protocols and/or link to existing offset programs such as the Clean Development Mechanism ("CDM"), and

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1/ Based on Moody's-Analytics Forecast for California Projects Real Annual Average GSP Growth.

2/ Even under the ARB's business as usual scenario, PG&E and CRA find that the containment reserve becomes stressed if the offset supply were to drop to a level below 4% (less than half the level allowed), while complementary measures provided fewer reductions than forecasted and an unexpected event occurred such as a drought or forced outage of one of California's nuclear units.

3/ A similar approach was included in Waxman-Markey Bill (American Clean Energy and Security Act of 2009) (H.R. 2454). Section 726 (Strategic Reserve).

   b. Linking with other cap-and-trade programs.

3. In the event additional and adequate supply of compliance instruments is not immediately available, temporarily suspend the cap-and-trade program and the entities' associated compliance responsibility until additional and adequate supply becomes available.

4. If the above measures are not successful, ARB should adjust the overall allowance budget commensurate with higher than expected economic growth or electric demand, or lower-than-expected availability of offsets or lower-than-expected effectiveness of program measures.

PG&E recommends the above corrective measures be taken to ensure an adequate quantity of compliance instruments is available and to avoid the potential for market failure. Additional supply may help to stabilize the cap-and-trade and related markets, such as the wholesale electric commodity market, and take pressure off the reserve. In the event adequate supply is not immediately available, suspension of the program and associated compliance responsibility will: 1) provide time for additional supply to be made available, and 2) will avoid price run-ups in wholesale electric commodity markets and other related markets.

C. PG&E Supports ARB's Proposal To Allocate Allowances To The Electric Local Distribution Companies ("LDCs") For The Benefit Of Customers.

PG&E supports ARB's proposal to allocate allowances to the electric distribution utilities for the benefit of their customers. We believe that the electricity sector has played and will continue to play a key role in the State's transition to a low carbon economy, and that a sufficient quantity of allowances should be allocated to the electricity sector to help facilitate that transition and provide assistance to California customers and businesses. We appreciate ARB's recognition that allowances allocated to utilities can help mitigate electricity customer costs and be used to further AB 32 goals. Our remaining comments associated with allowance allocation address: 1) the allocation to the electricity sector via utilities, 2) the divergent requirements for Investor-Owned Utilities ("IOU") vs. Publicly Owned Utilities ("POU"), and 3) allowance allocation among the utilities.

1. Disposition of Allowances: Allocation to Utilities

PG&E recommends that the quantity of allowances allocated to the electric sector via utilities be increased by 8.7 MMT for an electric sector total of 97.7 MMT/yr in 2012 and requests that § 95870 (c) be revised to reflect this. The increase reflects utilities' purchases of electricity from combined heat and power ("CHP") facilities. The regulation currently states that that 89 MMT of allowances times the cap adjustment factor in Table 9.2 will be freely allocated to electrical distribution utilities on an annual basis from 2012 to 2020. The Staff report notes that this estimate does not include emissions from electricity produced at CHP facilities and purchased by utilities. (Appendix J, page J-15.) PG&E agrees with the Staff report that the purchase of this electricity should be treated similarly to the purchase of electricity from other generators and that the sector's allocation should be adjusted to reflect electricity purchased from CHP facilities.

It is widely accepted that GHG compliance costs from a mandatory cap-and-trade program will flow to the ultimate consumer. In electricity markets, fossil generators will incur compliance costs and pass them through in the form of higher wholesale prices, with retail electricity customers ultimately paying for the increased costs. To the extent that CHP facilities generate electricity purchased by utilities, the cost of this power will also reflect this higher wholesale electric commodity price, which will in turn be paid by retail electric customers. To help electric retail customers manage these costs, the cost exposure from CHP generation purchased by utilities should be allocated to electric distribution customers on behalf of their customers.

PG&E's proposed 8.7 MMT adjustment associated with CHP generation delivered to the grid was quantified by estimating electric local distribution company ("LDC") purchases from CHP and multiplying them by a "payment" heat rate derived from the recent settlement proposed by key QF trade organizations[4/] and the 3 IOUs. For a heat rate, PG&E proposes an 8125 Btu/kWh rate, which is on the low end of a number of "payment" heat rates included this settlement.[5/] Assuming natural gas as a marginal fuel and current estimates of CHP grid deliveries, this translates to an additional allocation of allowances to the electric sector of 8.7 MMT per year.

PG&E further supports the ARB's proposal to allocate allowances to electric LDCs and not all retail procurement service providers. Utilities, both IOUs and POUs, are best positioned to further the goals of AB 32 by applying these allowances for customer benefit.

2. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers in an Equitable Manner

PG&E recommends that the ARB allocate allowances to utilities for the protection of electricity customers in an equitable manner. § 95892 describes the proposed allocation approach for IOUs and POUs. The regulation specifies that IOUs will be required to monetize freely allocated allowances at the auction, with the proceeds being returned to the utility and used for customer benefit as directed by the CPUC. The regulation further directs that the allowance value monetized at the auction be subject to the restrictions listed in § 95892(d). By contrast, the proposed regulation allows POUs to opt to direct their freely allocated allowances to their compliance account in contrast to requiring monetization and imposing restrictions on the use of the allowance value. PG&E does not object to the requirement that IOUs monetize their allowances at an auction and purchase allowances needed for compliance to address competition issues with independent generators, however we note that there is inherently less certainty that IOUs customers will realize the full value of the allowances since the IOUs will be required to

4/ The QF trade organizations include California Cogeneration Council (CCC), Independent Energy Producers (IEP), and California Association of California/Energy Producers and Users Coalition (CAC/EPUC).

5/ The settlement can be found at: (http://www.pge.com/includes/docs/pdfs/b2b/energysupply/qualifyingfacilities/settlement/final_term_sheet.pdf, p. 48).

sell and buy allowances in an auction. In contrast, POUs can opt to place their allocation directly into their compliance account.

PG&E does object however, to the unequal application of the restrictions outlined in § 95892 (d). We recommend that ARB provide both IOUs and POUs the same degree of flexibility to work with their regulators and governing boards to determine the best way to return revenue for customer benefit such that the utilities are able to achieve emission reductions called for under AB 32 while effectively managing costs to California and electric utility customers.

3. Allocation Among Electric Distribution Utilities

PG&E recommends an allocation of allowances among the electric distribution utilities for the benefit of customers that addresses the compliance burden for both high and low emitting utilities while recognizing early investments in low-emitting resources and energy efficiency. In addition, we believe it is important to transition to an approach that will provide long -term incentives for retail providers to reduce their reliance on high emitting generation resources.

PG&E supports proposals based on a mixture of historic emissions and sales which we believe satisfy the aforementioned objectives. Specifically, PG&E has previously supported a proposal by a subgroup of utilities recommending that allowances be allocated based on 75% historic emissions and 25% sales in 2012, transitioning to an allocation based on 25% historic emissions and 75% sales by 2020.

Alternative allowance allocation proposals have been developed and discussed among the utilities and CalEPA Staff in the last few weeks. PG&E will continue to work constructively with ARB, CalEPA and the other utility stakeholders to review the new proposals and determine if these alternative approaches meet the allowance allocation objectives outlined above.

D. An Adequate Supply Of Offsets Is Necessary To Ensure That The Goals Of AB 32 Are Achieved In A Cost-Effective Manner.

1. Carryover of Unused Rights to Use Offsets

PG&E believes that the supply of offsets in the first compliance period will be insufficient to cover 8% of emissions, as would be permitted under the proposed regulations. To address this shortfall, PG&E recommends that each covered entity be allowed to carry over any unfilled rights to use offsets. Such carry-over could be complicated if, for example, regulators allow trading of such rights. To avoid such complexity, PG&E proposes a simple method, in which no trading of unused rights is allowed and the burden of proof is on the complying entity.

For example, consider a facility X that emits 100,000 metric tons in each year. Under § 95854, facility X could cover 8% of its emissions, or 8,000 metric tons per year, by surrendering offsets rather than allowances. PG&E's proposal is simple: If facility X uses less than its full right, it can carry over that right. For example, facility X was allowed to use 8,000 offsets, but actually covered its emissions with 97,000 metric tons of allowances and only 3,000 offsets. In the next compliance period it would be allowed to use offsets equal to 8% of its emissions, plus 5,000 metric tons of offsets, to account for offsets that were not used in the first period.

PG&E proposes that the burden of proof be placed on the complying entity. ARB can easily determine whether the burden of proof has been met because ARB will be tracking the surrender of allowances and offsets in the Retirement Account.

2. Record Retention Requirements

PG&E appreciates the detail the ARB put into the record retention requirements. These requirements will help demonstrate that projects are real, additional, quantifiable, permanent, verifiable and enforceable. However, PG&E feels that the record retention period for Offset Project Operators or Authorized Project Designees are inconsistent with the verification requirements and too long for sequestration projects.

Per 95976 (e)(2), every offset project must retain all documents for “five years after the end of the crediting period for non-sequestration offset projects or, for sequestration offset projects, the length of time that the offset project is issued offset credits plus 100 years.” This is inconsistent with the record retention requirements for verification bodies in 95977 (e)(2)(C)(xi) – “The verification body must retain the sampling plan in paper, electronic, or other format for a period of not less than ten years following the submission of each Offset Verification Statement.” PG&E agrees with the implied logic for retention of records for verifiers – the risk of an error occurring with a particular vintage of offsets is most likely to occur within ten years of issuing the GHG emission reduction. Requiring the retention of records for more than ten years provides negligible value and is burdensome on Offset Project Operators or Authorized Project Designees. Therefore, we recommend that the ARB make the data retention requirements in 95976 (e)(2) consistent with the requirements in § 95977 (e)(2)(C) (xi).

3. Conflict of Interest Requirements

PG&E recognizes the potential problems which could occur for offset projects without a robust conflict of interest requirement. However, we are concerned that the Conflict of Interest Requirements in the Proposed Regulation Order are too restrictive and may prevent high quality projects from obtaining verification and capable verifiers from providing quality service. We appreciate the ability to use a verification body for the verification of carbon offset projects as long as previous work performed by the verification bodies, lead verifiers, and verifiers was not part of the current carbon offset verification process. This flexibility will allow large companies to use a verification body where the work can be demonstrated to be separate and distinct from previous work done by the verification body. PG&E also appreciates the inclusion of statements like “unless those systems will not be part of the verification process.”

PG&E recommends the ARB develop a review and appeal process similar to that allowed for the modification of Offset Project Data Reports in § 95977(e)(2)(C)(xix)(a) which would allow companies to have potential conflicts of interest reviewed by the Executive Officer. When the California Climate Action Registry started verifying emission inventories, there were companies that could not get their inventory verified because of the rigor of the conflict of interest requirements.

4. Re-verification of Offset Credits for Early Action

PG&E commends the ARB's recognition of offset credits for early action. The inclusion of the Livestock, Urban Forest, Ozone Depleting Substance, and Forest protocols will help provide offset credits to meet market demand in the first compliance period. Unfortunately, there are two significant challenges with the re-verification requirements in § 95990 (f). The most difficult is how to reconcile any differences found during a re-verification. For example, if the Climate Action Reserve's verification generated 100,000 metric tons, but the ARB's verification only yielded 90,000 metric tons, some of the offset credits created by the Reserve would not be valid. Multiple parties now own these credits and some may have been retired; reconciling this difference will be extremely challenging.

Further, requiring the re-verification of these projects will result in higher costs to the project which will discourage projects from entering the compliance market and further restrict offset supply. PG&E recommends that either the ARB rely on the original verification for these projects or allow existing offset credits to be used while making the necessary changes to the project for future vintages.

5. Additional Supply Needed to Meet Demand

The four offset protocols included in the proposed regulation is a great first step toward meeting the demand for offsets during the first compliance period. However, they will not generate sufficient volume to meet projected demand in the market. In addition, some of this potential may not be economical or practical to develop. PG&E estimates that these four protocols will generate at most 22 million metric tons of offsets during the first compliance period. We developed this estimate using the Climate Action Reserve's publicly available database. For projects that have been issued offsets, we extrapolated the volume out to 2014. For projects which are listed, but not yet delivering offsets, we estimated the volume that could be delivered in the first compliance period based on the performance of existing projects.

PG&E's estimate of 22 million metric tons between 2012 and 2014 is well below the 42.47 million tons of offsets allowed during the first compliance period. PG&E provides the recommendations below to increase volume.

a. Allow Use of Five Additional Climate Action Reserve Protocols

PG&E recommends that the ARB approve the use of the following Climate Action Reserve protocols:

- Coal Mine Methane
- Mexico Livestock
- Nitric Acid Production

- Organic Waste Composting
- Organic Waste Digestion

Unfortunately, only one of these five protocols has generated any offsets as of November 17, 2010 and it is too early to tell how much volume these protocols can generate. Based on our current knowledge, PG&E does not believe that these five protocols could generate the twenty million metric tons needed during the first compliance period. Therefore, ARB should consider additional options.

b. Use Of Offsets From Western Climate Initiative (WCI) Partners

PG&E supports the use of offsets generated under protocols developed by WCI Partner jurisdictions. Unfortunately, PG&E does not believe there to be appreciable additional volume from these jurisdictions based on the current protocols under consideration. The WCI's Offset Protocol Review Report lists nine different project types under consideration on page 7 of the report.[6/] Five of these protocols are already included in ARB's Proposed Regulation Order – Manure Management, Aforrestation & Reforestation, Forest Management, Forest Preservation & Conservation, and Urban Forestry. Waste and Wastewater Treatment projects can be included by approving the Climate Action Reserve's Organic Waste Digestion and Organic Waste Composting protocols. The ARB's Staff Report implies that the ARB will not consider Landfill Gas project types.[7/] This leaves Soil Sequestration and Rangeland Management as the only additional project types that could be allowed in California's cap-and-trade program. Unfortunately, protocols do not currently exist in any of the WCI Partner jurisdictions for these two project types. It has taken the Climate Action Reserve approximately 12 months to develop sequestration protocols. Assuming work on these protocols started immediately, the protocols would not be complete until the early 2012. Based on experience with forest sequestration projects, PG&E estimates that development of a soil sequestration or rangeland management project would take approximately 12 to 24 months. Because of this timeline, it is unlikely that significant volume of these projects will be developed in time to be used in the first compliance period.

Another option is the modification of the existing Climate Action Reserve protocols for use in Canada. This is similar to the approach being taken to adopt the forest and livestock protocols for use in Mexico. Unfortunately since work on the adoption of the protocols has not started, it is uncertain if these protocols can be modified in time for use during the first compliance period.

PG&E encourages the WCI, ARB and CAR to work together to quickly develop protocols for Partner jurisdictions. Since these protocols are unlikely to generate a sufficient volume of offsets

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6/ Western Climate Initiative Offset Committee, Task Group 3, and Det Norske Veritas (DNV). *Offset Protocol Review Report*. April 2010. http://www.westernclimateinitiative.org/component/remository/func-startdown/230/

7/ California Air Resources Board. 2010. *Proposed Regulation to Implement the California Cap-and-Trade Program*. Part I, Volume I, page III-11.

for use during the first compliance period, other options should be taken in conjunction with this development to provide the necessary volume.

c. Development Of Pilot REDD Projects

PG&E also supports the development of pilot REDD projects which could generate offsets in time for use during the first compliance period. Governor Schwarzenegger's recent Memorandum of Understanding with the Governors of Acre, Brazil and Chiapas, Mexico[8/] shows promise in the development of REDD projects. In particular, the guidelines developed by the government of Acre demonstrate that the state of Acre could develop up to 65 million offsets between 2011 and 2015.[9/] We encourage ARB to develop working group recommendations, as outlined in the mentioned MOU, that can meet ARB sector-based REDD offset criteria which can be adopted in time for use in the first compliance period. However, PG&E is concerned that the development of the necessary sub-national agreements and protocols will not happen in time to allow for the transfer of REDD credits for use in the first compliance period. Even if a large supply of offsets is developed, the use of sectoral credits is capped at 25% which translates into 10.62 million metric tons of offsets. This volume is not sufficient to fill the twenty million metric ton supply gap.

d. Use Of Climate Action Reserve Landfill Credits Generated Before 2012

Even if all three of the above recommendations are implemented, there will not be enough supply to meet the demand during the first compliance period. In addition, each of the above recommendations has a large number of unknowns and requires significant lead time. To help ensure adequate volume during the first compliance period, PG&E recommends the one-time use of offset credits generated from the capture of landfill gas between January 1, 2005 and December 31, 2011.

According to the Landfill Methane Control Measure approved on June 17, 2010 by the Office of Administrative Law, landfills have 18 months to install landfill gas collection systems.[10/] The current version of the Climate Action Reserve's Landfill Project Protocol allows GHG reductions to be reported up until the date that the installation of a landfill gas control system is legally required to be operational.[11/] The protocol goes on to state that "If the landfill's methane emissions are included under an emissions cap (e.g. under a State or Federal cap-and-trade

8/ Office of the Governor. 2010. *Gov. Schwarzenegger Announces Agreement with Mexico and Brazil to Combat Climate Change, Protect Forests at GGCS 3*. http://gov.ca.gov/press-release/16496

9/ Acre Government. 2009. *Plan for Valuing Forest Assets*. Page 30. http://www.katoombagroup.org/rapidresponse/Acre%20PES%20Carbon%20Project%20exp%20version%2006nov09.pdf

10/ California Air Resources Board. 2010. *Final Regulation Order – Methane Emissions from Municipal Solid Waste* Landfills. § 95464(a)(5). http://www.arb.ca.gov/regact/2009/landfills09/landfillfinalfro.pdf

11/ Climate Action Reserve. 2009. *Landfill Project Protocol*. Page 9.

program), emission reductions may likewise be reported to the Reserve until the date that the emissions cap takes effect."[12/]

There are four landfill projects in California listed under the Climate Action Reserve's Landfill Gas Protocol which are using this approach to generate GHG emission reductions. These landfills, as well as those from outside of California, should be allowed to receive credit for their efforts to capture GHG emissions in advance of being required by the regulations.

As of November 17, 2010, there are approximately 3.9 million metric tons of offsets verified under the Landfill Gas protocol. PG&E estimates that this volume will increase to almost ten million metric tons by the end of 2011. Combining the one-time use of landfill gas capture projects in the United States with the other options presented above is necessary to meet the forecasted demand during the first compliance period.

6. Compliance Pathways Analysis

PG&E reviewed the offset price estimates presented in Appendix F and offers the following feedback. On page F-42, the price of forestry offset credits is estimated at $4 per metric ton. Based on experience through PG&E's ClimateSmart™ program, forestry offset projects are currently being sold for between $7 and $10 per metric ton. Ozone-depleting substance and livestock methane capture projects go for between $5 and $7 per metric ton. This is consistent with an annual report on the voluntary market which shows an average price of forest management projects at $7.3 per metric ton and livestock methane capture projects at $5.7 per metric ton.[13/]

7. Allowance Containment Reserve Analysis

ARB's forecast estimates provided in Table G-1 of Appendix G overlook two important items. First, the forecast assumes that offset volume is only dependent on price and second, that a sufficient volume of offsets will be developed if the price is high enough. This forecast does not consider the limits based on the current approved protocols and the "feedstocks" needed to develop GHG emission reductions. For example, at the ARB's June 22, 2010 workshop, ARB Staff estimated the volume of GHG emission reductions from ozone-depleting substances at 30 million metric tons between 2012 and 2014. This estimate was based on existing ODS banks calculated by the U.S. Environmental Protection Agency ("EPA"). When estimating supply, any analysis needs to consider that once these ODS are destroyed, there is no additional volume. For livestock manure capture projects, the number of projects is limited by the number of cows. It is estimated that there are 1.4 million dairy cows in California.[14/] The average cow generates about

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12/ Climate Action Reserve. 2009. *Landfill Project Protocol*. Page 9.

13/ Bloomberg New Energy Finance and Ecosystem Marketplace. 2010. *Building Bridges – State of the Voluntary Carbon Markets 2010*, figure 22, page 35.

14/ U.S. Environmental Protection Agency. 08/11/09. *California Animal Waste* Management, http://www.epa.gov/region9/animalwaste/california.html

5 metric tons of carbon dioxide equivalent per year.[15/] Therefore if the methane was captured from every dairy cow in California, you would only generate 7 million metric tons of GHG emissions per year. In order to meet the demand for the first compliance period, every dairy and every ozone-depletion substance bank would need to be in the process of developing their projects. Because offsets are limited by the feedstocks (refrigerants, cows, trees), it is not possible to meet the theoretical potential in this analysis even at high offset prices.

E. PG&E Requests Clarification Of The Role Of Out-Of-State Renewable Energy Purchases In California's Cap-And-Trade Program.

PG&E recommends ARB 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 are consistent and achieve GHG reductions in the most cost effective manner. As such, the Mandatory Reporting Regulation should 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 ensures that California receives the full GHG-reduction benefits of the State's renewable programs by providing consistency 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 recognize the GHG attributes from these RPS contracts 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.

ARB need not, and appropriately should not, follow a widely disfavored recommendation of the Western Climate Initiative (WCI) in addressing how renewable generation is to be treated. The ARB should provide that any resource eligible under the RES or RPS is credited as zero GHG in order to ensure the RES, RPS cap-and-trade and Mandatory Reporting Regulations are consistent and achieve GHG reductions in the most cost-effective manner possible. PG&E provides further detail on this issue in our comments submitted in response to the Mandatory Reporting Regulation.

F. ARB Should Provide Additional Support For The Revised 2020 Allowance Budget.

PG&E requests further clarification and examination of the cap-and-trade program's allowance budget for the year 2020 as established in § 95840. The Scoping Plan included a preliminary estimate of 365 million metric tons (MMT). The cap-and-trade proposed regulation proposes a substantially lower allowance budget of 334.2 MMT. Given the importance of the year-2020 allowance budget to the cap-and-trade program, it must be a credible and well-supported number.

15/ California Energy Commission. 2006. *Dairy Power Production Program*. Calculated based on the average of the ten dairies that participated in the program.

The method to establish the preliminary estimate of 365 MMT is clearly described in the December 2008 Scoping Plan:

> "The Scoping Plan must be designed to meet the AB 32 goal of reducing statewide emissions to 1990 levels by 2020. To meet that target, the emissions allowed under a cap-and-trade program, plus expected emissions from sources not included under the program's cap, must be no greater than the 2020 emissions goal." (Appendix C, page C-16.)

The Scoping Plan describes what might be called a "top down" method. The top is set by statute: Statewide emissions in 2020 are not to exceed emissions recorded in 1990, which ARB has established as 427 MMT. Staff first subtracted a safety margin of 5 MMT from the 1990 value, which reduces the overall cap from 427 MMT to 422 MMT. Second, Staff subtracted the expected emissions from sources not included in the cap-and-trade program, which were 57 MMT.[16/] Subtracting 57 MMT from 422 MMT yields 365 MMT, which are the allowable emissions from sources within the cap-and-trade program in 2020, or in other words, the allowance budget for 2020. The "top down" approach is simple, logical and only involves emissions in the years 1990 and 2020.

In the cap-and-trade proposed regulation, Staff used data for 2008 to adjust the proposed allowance budget for 2020. (Appendix E, page E-8.) PG&E does not fully understand Staff's adjustment.

The "top down" method highlights a significant increase in Staff's emission projections for 2020 from sectors and sources outside the cap-and-trade program. In the Scoping Plan, as noted above, expected emissions from sources outside in the cap-and-trade program were 57 MMT in 2020. In the final draft regulation, the 57 MMT has increased to 85 MMT.

PG&E appreciates Staff's assistance in providing background information on Staff's projections of year 2020 emissions from sources outside the cap-and-trade program, but would like to better understand why the forecast has increased by such a large amount. For example, in the ARB's emission inventory, emissions of gases with high Global Warming Potential increase from about 10 MMT CO2e in 2000 to about 15 MMT CO2e in 2008. Simple extrapolation, ignoring the recent economic downturn, would suggest a forecast of about 22 MMT CO2e in 2020, but Staff's forecast is 36 MMT CO2e. Using 36 MMT rather than 22 MMT shrinks the allowance budget in 2020, which impacts the allowance budgets for the entire program. PG&E therefore requests additional information related to Staff's revised forecasts of emissions outside the cap-and-trade program.

16/ In the December 2008 Scoping Plan, the 57 MMT can be calculated by adding the "Projected 2020 Emissions (BAU)" in Table 1 for sectors outside the cap, namely Recycling and Waste, High GWP, Agriculture, and Forest Net Emissions, leading to a figure of 84.4 MMT, and subtracting the "Estimated Reductions from Uncapped Sources/Sectors", shown in Table 2 as 27.3 MMT. The difference is 57.1 MMT.

G. Growth Resulting From Vehicle Electrification Should Be Accompanied By A Commensurate Allocation to Protect Utility Customers From Increased Compliance Costs.

PG&E believes that the increased use of electric fuel is an important strategy for reducing statewide emissions, and commends Staff for its attention to promoting electrification (Initial Statement of Reasons ("ISOR"), page II-33). However, PG&E is concerned about the interaction of the cap-and-trade program with other policies that encourage vehicle, port, off-road equipment and goods movement electrification. Electric fuel will increase statewide electricity consumption, and associated GHG emissions. While society will experience lower overall emissions, increased electric sector emissions will result in higher electricity costs, which utility customers will bear through increased rates. PG&E is concerned that this circumstance may create disincentives for utilities and their ratepayers to support transportation technologies that use electricity, reducing the potential to achieve the benefits associated with transportation sector electrification. PG&E agrees with the CPUC's assessment that "failure to make available additional allowances to the electricity sector due to electrification risks overburdening ratepayers with the cost of transportation sector emissions".[17/]

To ensure that electric fuel is encouraged, consistent with the goals of AB 32, PG&E recommends that ARB address increased costs to the electric sector through allocation of allowances in the cap-and-trade program. PG&E believes that allowances associated with electric fuel should be returned to electric ratepayers, under the guidance of the CPUC and municipal utility boards, so that the value of allowances flow directly to the customers who bear the carbon costs associated with electric fuel.

H. ARB Should Postpone Consideration of Allowance Allocation To Natural Gas Utilities For Customer Benefit To Allow For Thorough Evaluation.

The proposed regulation does not specifically address the issue of small natural gas customer allowance allocation at this time. Unlike allowance allocation for the electric sector, which has been the subject of significant analysis and discussion during this rulemaking, the issue of natural gas allocation has not been thoroughly assessed. Because small natural gas customers will not be placed under the cap until 2015, PG&E recommends the ARB defer its decision on how to allocate allowances to the sector.

PG&E has not yet determined whether the efficiency goal for small natural gas customers is achievable and is not aware that such a study has been completed. PG&E notes that energy efficiency is the primary if not exclusive means for reducing emissions in this sector. Achieving this level of emissions depends on the rate of economic growth in the State, the efficacy of State building and appliance standards, sufficient funding for energy efficiency from the CPUC,

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17/ California Public Utilities Commission, Policy and Planning Division. Staff White Paper: "Light-Duty Vehicle Electrification in California: Potential Barriers and Opportunities. May 22, 2009.

municipal utility boards and other sources, and the effectiveness of utility-sponsored programs. PG&E recommends this issue be carefully assessed and natural gas LDC allowance allocation be reviewed at a later date in light of this assessment.

I. Any Proposal To Remove Or Retire Allowances To Reflect Voluntary Renewables Should Preserve The Environmental Integrity Of AB 32 And Not Increase The Compliance Costs For Utility Customers And Other Participants.

PG&E appreciates that Staff intends to provide additional detail on a possible future account for a voluntary renewable energy allowance set-aside (§ 95831(6) and ISOR, page 58), and can provide additional comment at that time. In the interim, PG&E wishes to reiterate policy principles highlighted in previous written comments to the ARB.

PG&E's overarching policy principles, with respect to AB 32 implementation, are to preserve the environmental integrity of the program, while managing customer costs. PG&E believes that any proposal that removes allowances from the market must align with these principles. Therefore, any proposal to remove or retire allowances to reflect voluntary renewables should preserve the environmental integrity of AB 32 and not increase the compliance costs for utility customers and other participants. To accomplish this, we believe that it is important that any allowances removed for voluntary renewables be linked to actual generation rather than potential generation, and be based on a rigorous emissions reduction methodology associated with this renewable generation.

J. ARB Should Provide Additional Detail On Auction Design In The Proposed Regulation.

1. ARB Should Provide Additional Details On The Design And Implementation Of The Proposed Cap-And-Trade Auction

PG&E recommends that ARB include additional regulatory language detailing the design and implementation of the cap-and-trade auction to ensure efficient market functioning. The proposed regulation lacks sufficient detail concerning market systems, information systems and trading platforms for the primary auction market.

The key lessons from the inter-related failures of California's energy markets during the 2000-2001 energy crisis demonstrate the need for detailed planning and systems development for a GHG cap-and-trade market. There is a need for ARB to address and resolve key auction design issues that will enable parties to proceed with their commercial arrangements in a timely and orderly manner.

We recommend that ARB provide additional detail in the proposed regulation on auction design including the following: credit management process, default management process, definition of security and rating requirements, credit terms, revenue shortfall allocation, and settlements. In addition, we recommend that the ARB address a number of questions, including:

- Will ARB Staff or a third party contractor administer the auctions? This issue needs to be resolved promptly to allow sufficient time to address credit requirements, default provisions, and other auction design details.

- What specific credit, collateral and security requirements will be imposed on all parties in the quarterly auctions?

- How will ARB manage the credit process for each auction? How will ARB handle defaults? How will ARB perform settlements?

- What is the potential for market abuse or manipulation e.g. “cornering” or “squeezing,” in the quarterly auctions at the end of a three-year compliance period, when the allowance needs of covered entities are more defined?

PG&E recommends that ARB modify the proposed rule to address these and other critical auction design issues. This will ensure that the systems and resources are in place to support a fully tested and workable market. In addition, PG&E believes it is important to review how the primary auction market will interact with secondary bilateral markets.

2. Timing of Allowance Allocation and Auction Notification Requirements

The proposed regulation may inadvertently prevent electric distribution utilities from selling allowances in the first quarterly auction of each year. § 95910(d)(4) notes that allowances consigned to auction at least 60 days prior to the regular quarterly auction will be offered for sale at that auction. § 95910(a) notes that an auction will occur on the twelfth business day of each calendar quarter, except for the very first auction, which is to be held on February 14, 2012. However, pursuant to § 95870(c)(1), the Executive Officer is not required to allocate allowances to electric distribution utilities until January 15 of each calendar year, after the deadline for consigning allowances to the first quarterly auction of each year. PG&E understands that ARB is aware of these timing issues and is working to change the dates as appropriate.

3. Treatment of Advance Auction Allowances That Are Unsold at An Auction

§ 95911 (b) (4) states that allowances designated by ARB for an auction that remain unsold go to the highest tier in the Reserve. PG&E strongly recommends that these allowances instead go back to the auction account and be made available at the next auction. Furthermore, PG&E understands that this language does not pertain to the “advance auction” allowances. Advanced auction allowances that remain unsold will go back to the auction account. PG&E requests that ARB add language to clarify this provision.

4. PG&E Requests Additional Clarification On Text Related to Auction Design.

§ 95814(a)(2)(A) would allow registration as a Voluntarily Associated Entity to an entity "that intends to purchase, hold, sell or voluntarily retire compliance instruments." However, § 95802(a)(207) defines a Voluntarily Associated Entity more narrowly, as an entity that "intends to voluntarily retire compliance instruments…". PG&E understands that ARB's intent is to use the definition in § 95814(a)(2)(A) and will correct the definition in § 95802 (a)(207).

§ 95911 (c) (2) references the auction purchase limit in "(A)". PG&E believes that ARB intended to reference (1) instead of (A) at the end of that sentence and that ARB will amend this provision to reflect this.

§ 95922 (a) and (b) refer to § 95930, however, that section does not exist. PG&E believes that ARB intended to reference § 95830 and that ARB will amend the regulation to reflect this.

K. The Allowance Holding Limit Should Not Be Applied to Regulated Utilities.

PG&E recommends that ARB amend the holding limit in § 95920 of the proposed regulation. PG&E supports a holding limit for unregulated entities. However, PG&E believes a holding limit is not necessary for regulated utilities. Utilities do not have any incentives to boost allowance prices because they have cost-based rates for service. In addition, utilities face various requirements to hedge against volatile commodity prices, which are likely to conflict with the holding limit.

PG&E, by virtue of its electricity and natural gas services, has a greater need for allowances than perhaps any other single entity. A one-size-fits-all holding limit, if designed to accommodate PG&E's need, could be quite high. With that in mind, PG&E believes an exemption for regulated utilities is an appropriate policy choice.

PG&E proposes an exemption for regulated utilities, to be added to § 95920(b)(2), as follows:

> No holding limit shall be applied to the holdings of a publicly owned utility operating under a plan approved by the governing board of the utility. No holding limit shall be applied to the holdings of an investor-owned utility operating under a plan approved by the California Public Utilities Commission.

Although PG&E has offered specific language, PG&E is open to alternatives for setting the holding limit and counting toward it in a way that enables a regulated utility to implement an orderly and gradual purchase of allowances over time and to effectively manage the volatility in allowance prices.

L. ARB Should Make Available a Greater Number of Future-Vintage Allowances To Help Complying Entities Manage Compliance Costs.

PG&E urges ARB to amend the Proposed Regulation to allow for auctioning of a substantial number of future-vintage allowances, so that complying entities can manage costs over time.

The benefits of auctioning future-vintage allowances are widely known. For example, the "Detailed Program Design Document" issued by the Western Climate Initiative (Appendix I) states: "Allowances from future compliance periods may be sold concurrently to aid market liquidity, reduce uncertainty, and contribute to market efficiency" (Page I-26). Furthermore, authorization is not an issue because the Proposed Regulation allows auctioning of future-vintage allowances. Specifically, § 95910(b) states that: "An allowance may be designated for auction prior to its vintage year."

Under § 95870(b) and 95910(c)(2), ARB will auction 2% of the 2015 allowance budget in 2012, 2% of the 2016 allowance budget in 2013, and so on. This is a step in the right direction, but a small step; no allowances of the 2013 and 2014 vintages will be auctioned in 2012, and 2% of the 2015 allowance budget is less than 8 million allowances. Therefore, PG&E recommends that a significant quantity of future vintage allowances be made available through the auctions to effectively manage compliance costs and volatility. PG&E requests amendment of § 95870(c)(1) so that complying entities can execute approved hedging plans. The goal is to enable hedging by increasing market liquidity through orderly, gradual auctioning of substantial numbers of allowances prior to their vintage years.

M. ARB Should Amend Its Rules To Be Consistent With The Three-Year Compliance Period.

ARB explained its choice of the three-year compliance period as follows:

> "A number of significant sources of California emissions are subject to significant year-to-year variations—for example, electricity sector emissions increase in low water years as hydropower generation is replaced with natural gas generation. For this reason, the proposed program has been designed with a three-year compliance cycle to help smooth out these annual variations, and to provide sources with greater flexibility to reduce emissions." (ISOR, Page II-4)

If, for example, the year 2012 is a dry year with higher electricity sector emissions, ARB apparently intended to approve the use of 2013-vintage allowances to cover the higher emissions in 2012. PG&E supports ARB's choice of a three-year compliance period, and requests that ARB clarify the proposed regulation as necessary to ensure that ARB's intention is achieved. As currently written, § 95856(b)(2) appears to require that each ton of emissions be covered by an allowance from the same or a prior budget year, so that higher emissions during a dry 2012 could not be covered by 2013-vintage allowances:

> "To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year during which the compliance obligation is calculated… "

PG&E suggests that the section be amended to read as follows:

> "To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the ~~year~~ three-year compliance period for which the compliance obligation is calculated…"

N. ARB Should Clarify The Treatment Of Biogas, Biomass, And Natural Gas System Fugitive And Vented Emissions.

1. Biomass-Derived Biofuels Should Not Be Subject To 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."[18/]

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:

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.[19/] The protocol specifically notes

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18/ 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.

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

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.[20/]

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[21/] and the EPA in its Mandatory Reporting of GHG Rule[22/] 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."[23/] 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."[24/] Finally, DOE's voluntary GHG reporting program, 1605(b), states that "carbon dioxide emissions of biogenic fuels do not "count" as 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."[25/]

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,[26/] 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.

20/ 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.

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

22/ 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.

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

24/ U.S. Environmental Protection Agency. 2010. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008*. Chapter3. Page 3-17. http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Chapter3-Energy.pdf

25/ 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

26/ 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

2. ARB Should Clarify the Treatment of Biogas and Biomass.

PG&E recommends that ARB clarify the treatment of biogas and biomass as described in Subarticle 7. § 95852.2(a) exempts combustion emissions from biomass-derived fuels from a covered entity's compliance obligation, except for biogas from digesters, while §95852.2(e) exempts biomethane from all animal and other organic waste, landfill gas and wastewater. This section therefore appears to state that if biogas from digesters were combusted, those emissions would not be exempt, but if biomethane[27/] were released into the atmosphere, those emissions would be exempt. PG&E recommends that §95852.2(a) be modified to state: "Combustion emissions from biomass-derived fuels ~~(except biogas from digesters)~~ from the following sources" and that §95852.2(e) be modified to state "Combustion and fugitive biomethane emissions from the following sources:"

3. Fugitive and Vented Emissions from Natural Gas Systems Are Included as Part of the Natural Gas Supplier Compliance Obligation and Should Not Have an Additional Direct Compliance Obligation.

The ISOR states, "In the initial compliance period, beginning in 2012, the program will cover emissions from electricity, including imported electricity; industrial fuel combustion at large sources; and industrial process emissions, excluding fugitive emissions." However, § 95852.2(f)(5) exempts only certain fugitive emissions listed in § 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems. Specifically, the regulation only exempts facility types in § 95101(e) that have leak detection and leaker emission factors, as well as stationary fugitive and "stationary vented" sources on offshore oil platforms. PG&E recommends that §95852.2(f)(5) be amended to read:

> ~~At t~~The facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems.~~: leak detection and leaker emission factors, stationary fugitive and "stationary vented" sources on offshore oil platforms~~

PG&E recommends that § 95811 also be revised to reflect this change. Fugitive and vented emissions from natural gas systems are already being captured under the compliance obligation of Natural Gas Suppliers, since these entities will report using an "upstream approach," meaning that the compliance obligation will be based on the volume of gas received at the State border or city gate minus volume of gas delivered to storage or entities directly regulated. Therefore, fugitives and vented emissions should be exempt from a direct cap-and-trade compliance obligation because they are already being captured under the compliance obligation of Natural Gas Suppliers.

27/ ARB Staff noted in a call with PG&E staff on 11/18/2010 that biogas is different than biomethane, (i.e., biogas is unrefined biomethane). However, neither is defined in the proposed regulation.

Further, fugitive and vented emissions from sources that use population emission factors to calculate them should be exempt from a cap-and-trade compliance obligation because the methodology is not rigorous enough. Staff's ISOR for the Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions supports this: "a methodology using population counts and use of generic emissions factors would not provide compliance grade data for a cap-and-trade program."[28/]

U.S. EPA's final Subpart W uses population emission factors to calculate emissions from most of the fugitive and vented emissions from natural gas systems that are not currently exempt from a compliance obligation under ARB's proposed regulation. If ARB were to adopt EPA's methodology, which PG&E recommends to ensure consistency between State and Federal programs, then those emissions should be exempt from a compliance obligation because it is widely acknowledged that leaker and population emission factors for fugitive and vented emission sources in natural gas systems are very imprecise and not rigorous enough for a cap-and-trade program. For example, EPA's emission factor for plastic pipe, which is similar to that of ARB's, was based on only six data points collected nearly 20 years ago, one of which was a plastic pipe that had ruptured and was blowing natural gas. That type of rupture is repaired promptly and does not continue emitting natural gas from the distribution system at the same rate all year. Yet the plastic pipe emission factor in the reporting regulation makes that assumption.[29/]

In addition, PG&E has been reporting the fugitive and vented emissions from its natural gas system in detail since the 2007 reporting year to The California Climate Action Registry (CCAR) and since 2008 to The Climate Registry (TCR), and has documented extensive variability in these emissions depending on the reporting methodology employed. For example, using the same 2009 data for PG&E's distribution main pipelines, the emissions resulting from the use of emission factors from the CCAR draft protocol[30/] that is accepted for use by those voluntary reporting programs (and which ARB Staff helped develop) are completely different than the ones used by EPA/ARB, and the completely different again from PG&E's more detailed, system-specific methodology.[31/]

28/ ARB Staff Report: Initial Statement of Reasons. Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32). October 28, 2010, p. 82.

29/ AGA. "Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comment," page 22. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_RTC_part1.pdf

30/ URS Corporation and the LEVON Group. CCAR/WRI Discussion Paper for a Natural Gas Transmission and Distribution Greenhouse Gas Reporting Protocol, Final Draft Protocol, June 6, 2007. http://www.climateregistry.org/resources/docs/protocols/progress/natural-gas/CCAR-WRI_NG_Protocol_DiscussionPaper_Final.pdf

31/ Calculated using the PG&E IGIS database (leak database) to determine leak hours from known open leaks at the start of the study year, additional leaks discovered during the study year through leak surveys, and additional leaks discovered during the study year through "call-ins." The leak hours are multiplied by leak loss rates (cubic feet per hour) developed by sampling leaks (sample data developed by PG&E for its 1987 leakage study or by SoCal Gas for its 1991 leakage study).

Distribution Main Pipeline Fugitive Emissions *(in MT CO2e)*	EPA Subpart W	2007 Draft CCAR Protocol	PG&E Methodology
TOTAL	129,109	178,583	34,552

Because of the imprecise methodologies used in calculating natural gas system fugitive and vented emissions, and because these emissions are already being captured under the compliance obligation of Natural Gas Suppliers, they should be exempt from a direct cap-and-trade compliance obligation.

4. ARB should amend the exemptions reference in § 95852 (h) (v)

§ 95852 (h) (v) references exemptions listed in § 95852.2(a)(6), however, that section does not exist. It is PG&E's understanding that the list of exemptions in part (v) is supposed to reference § 95852.2 (f).

O. ARB Should Enforce AB 32 In A Manner Which Is Reasonable And Consistent With Other Stationary Source Violations.

1. Violations

PG&E supports full and fair enforcement of AB 32 to achieve the State's GHG emission reduction targets in a timely manner. We recommend, however, that ARB revise the proposed regulation to ensure that penalties for cap-and-trade violations are commensurate with the scope and severity of the violation and potential environmental harm, and are consistent with penalties for other stationary source violations.

Subsections (a) and (b) of proposed § 96014 specify that violations for failure to surrender the required number of compliance instruments are a separate violation for each missing compliance instrument, and are a separate violation for each day after the specified compliance date that a required compliance instrument has not been surrendered. Since each "compliance instrument" is equivalent to one metric ton of GHGs (proposed § 95802(a) (36)), these subsections together result in a "per metric ton per day" penalty approach. In other words, for any shortfall in providing compliance instruments, each metric ton of the shortfall is a separate violation for each day until the shortfall is corrected. The violation period would begin after the deadline for submitting compliance instruments is missed, continuing until the shortfall is corrected. Under proposed § 96013, the stationary source penalty authorities of Health and Safety Code Sections 42400 *et seq.* would apply.

In addition to these provisions governing potential monetary penalties, the proposed cap-and-trade rule provides an automatic emissions penalty of four times the "excess emissions" for failure to timely submit the required amount of compliance instruments. See proposed § 95857(b). The proposed rule also allows for a 30-day period to be provided allowing a covered entity time to obtain the compliance instruments needed to correct a shortfall (including the 4x multiplier). See § 95857(c)(4)(6).

PG&E appreciates ARB's proposal that violation days accrue only after the deadline for submitting compliance instruments has not been met. We believe this is a much better approach than specifying that when a shortfall occurs, any violation existed over the entire relevant compliance period (and therefore would automatically be 365 violations for an annual compliance period).

However, PG&E does not support ARB's proposal that each missing compliance instrument (i.e., each metric ton of any shortfall in surrender of allowances) be considered a separate daily violation. Given the magnitude of stationary source annual GHG emissions, treating each missing compliance instrument as a separate violation for every day the shortfall continues is likely to result in extremely large numbers of "violations" for each occurrence of a shortfall. Large numbers of "violations" in turn create the possibility for extremely large penalties, which are likely to be well be out of proportion to any actual harm or economic benefit of noncompliance.

In PG&E's view, the proposed cap-and-trade program should include violation provisions and penalty guidelines that ensure that penalties are appropriate for the size and duration of any failure to submit compliance instruments, that ensure that penalty exposure is consistent with existing stationary source penalty assessments, and that ensure that total penalty amounts are not unreasonably large simply because GHG emission rates are large in comparison to emission rates for traditional air pollutants. This large difference in emission rates could result in a disproportionate GHG penalty.

To achieve these goals, PG&E recommends the following approach to enforcement for the cap-and-trade program. First, § 95857(b) should be revised to eliminate the 4x multiplier for excess emissions resulting from "untimely surrender," and instead require surrender of sufficient compliance instruments to make up the shortfall on a 1:1 basis, and impose a requirement for a cash payment of three times the quantity of excess emissions, multiplied by the most recent allowance market price. This approach would have the same economic impact on the source as the 4x surrender requirement, while avoiding potential adverse market effects resulting from artificially decreased supply of allowances. Second, § 96014(a) and (b) should be revised so that no violation occurs if a compliance shortfall is cured under § 95857 within the 30-day cure period, and that failure to cure a shortfall within the 30-day period is a single violation per day from the end of the 30 days until the shortfall is made up and the cash payment is made.

2. Authority to Suspend, Revoke, or Modify

As proposed, § 96011 would allow suspension, revocation or restriction of holding accounts and Executive Orders when an entity is "determined to be in violation of any provision" of the cap-and-trade rule. These provisions do not specify whether the Executive Officer makes that determination, the basis for the determination (i.e., issuance of Notice of Violation ("NOV"), settlement, court finding), or how and when a suspension, revocation or restriction is lifted.

PG&E suggests that this section would be improved by adding further clarity and specific criteria with regard to determining whether a violation occurred, and for the duration and removal of any suspension, revocation or restriction. For example, "determined to be in violation" should require that an NOV has been issued. Once an alleged violation is resolved (whether through a settlement, court action, or otherwise), any suspension, revocation or restriction should be lifted except where unusual circumstances justify continuing the suspension, revocation or restriction.

P. ARB Should Closely Monitor The Cap-And-Trade Program And Implementation Of The Scoping Plan To Ensure The State Meets AB 32 Emission Reduction Targets In A Cost-Effective Manner.

1. Cap-and-Trade Program Monitoring

In Section Q of the ISOR, Staff notes that "unanticipated effects and results could occur over the life of the [cap-and-trade] program" in light of its complexity, multiple objectives and the "cumulative actions of a large number of participants operating in a complex market system" (ISOR, Section Q, page II-56).

Staff notes further that ARB will "monitor whether, over time, the program is meeting all of its objectives set forth in AB 32," including ensuring "beneficial outcomes" as well as minimizing or avoiding certain "adverse consequences." Staff proposes that ARB use the "results of this monitoring" to do a regular evaluation of the program (at a minimum, once every compliance period).

PG&E supports Staff's call for regular program monitoring, and has the following additional recommendations to avoid or mitigate further any adverse and unforeseen consequences from the program:

a. <u>Formally review the cap-and-trade program at least once during each compliance period, and at other times as needed</u>. PG&E believes that the "adverse consequences" noted by Staff in the ISOR should include the potential for market failure or unsustainably high allowance prices. Although we expect ARB to immediately review the program under such circumstances and take immediate corrective action, we support Staff's suggestion that the program should be reviewed at least once each compliance period. Further, we believe this review must happen no later than the middle of each period to allow sufficient time for any necessary adjustments to the program. This would mean no later than the summer of 2013, for example, for the first formal review. This review and formal Board consideration should ideally be preceded by workshops and opportunity for public notice-and-comment.

We recommend that this process and these dates be written into the regulation, as they are in other ARB regulations, including the Low Carbon Fuel Standard ("LCFS"). Further, the regulation should provide a list of specific areas and issues that should be considered in such a review. This approach is also consistent with other ARB regulations (See LCFS § 95489 and RES § 97011). For the cap-and-trade regulation, this review should specifically address the elements listed in the ISOR's program monitoring section, including monitoring the price and bid for allowances in the quarterly auctions, the functioning of secondary markets, adequacy of the Allowance Price Containment Reserve, detection of market manipulation, the potential for leakage, offset supply, and evidence of contract shuffling.

b. Establish a formal and independent "Market Monitoring Board." In addition to the scheduled reviews recommended above, PG&E requests that ARB create a more formal and independent market monitoring function. ARB could, for example, develop a "Market Monitoring Board" whose role is to regularly assess the soundness of the cap-and-trade market and/or the functioning of the market. This Board could convene regularly, or at least quarterly after each auction. This committee could be made up, for example, of key representatives from ARB, the CPUC and CEC, and the California Independent System Operator, but might also include other designated market experts. This committee could also be authorized to make recommendations to the ARB for immediate corrective actions or to the Governor for temporary suspension of the program (as permitted under AB 32). PG&E believes that the complexity of the cap-and-trade market and its impact on consumer costs warrants this type of specified and structured process.

2. Scoping Plan Review and Cost-Effectiveness Assessment

a. PG&E believes that Scoping Plan updates are critical and should be performed every three years rather than the five-year cycle that the statute provides as a minimum. AB 32 provides that ARB must update the Scoping Plan at least once every five years. The suite of programs ARB and its sister agencies are adopting under AB 32 are complex, and in the case of the electric sector in particular, rely on continuously evolving advanced technologies and challenging and unpredictable transmission and permitting conditions, among other uncertainties. For these reasons, PG&E believes that Scoping Plan updates are critical, and moreover, should be more frequent than the five-year cycle that the statute provides as a minimum.

In particular, and as it relates to the cap-and-trade regulation, PG&E recommends that the relative cost-effectiveness of programs must remain a key consideration as California moves forward to achieve AB 32's goals. While PG&E appreciates ARB's diligent work on identifying abatement opportunities through the Compliance Pathways analysis, throughout Appendix F, Staff acknowledges instances where it was necessary to make assumptions about reduction potential and associated costs in order to fill data gaps. These assumptions highlight uncertainty around the relative cost-effectiveness of program measures and cap-and-trade as well as the actual emissions reductions that may be achieved through these program measures. The Scoping Plan notes that as ARB progresses "from proposed measures and estimated costs to actual regulations, the comparison of cost-effectiveness would move toward the well established practice of comparing the cost-effectiveness of *new regulations* to the cost effectiveness of previously enacted and/or *similar regulations*" (Scoping Plan, December 2008, page 85, emphasis added).

b. ARB should establish a clearer process for evaluating comparative cost-effectiveness as an integral part of Scoping Plan review. Since AB 32 calls for maximizing cost-effectiveness, ARB should establish a clearer process to assess each program measure to determine the cost per tonne of CO_2-equivalent reductions. Next, ARB should perform a comparative evaluation to determine the relative cost-effectiveness of each program measure vis-à-vis other programs and the cap-and-trade market. Finally, the ARB should make adjustments to the program measures to maximize the extent to which regulated parties are able to pursue the most cost-effective measures, and to either improve the cost-effectiveness of the more costly programs, delay their compliance targets if cost trajectories are trending downward, or suspend programs entirely in favor of other program measures or the cap-and-trade market. This cross-measure comparison could also be used to expand programs that prove to be more cost-effective than others.

PG&E proposes that these cross-measure assessments be performed at least every two years, and ARB would modify the programs as necessary in order to minimize higher program costs and to more accurately determine cost and emissions reduction trajectories. In the electric sector, existing reporting requirements should provide ample data to determine the reductions achieved by each of the program measures, while the cap-and-trade market provides a real-time allowance price by which to evaluate its comparative cost-effectiveness.

The ARB should employ a comparative approach to cost-effectiveness evaluation, adjust program requirements as required to improve their cost-effectiveness and allow reductions to be achieved through switching to more cost-effective program measures or rely on more reductions through the cap-and-trade system when necessary.

PG&E recommends that comparative cost-effectiveness analysis be a key component of Scoping Plan review, and that such review occur at least every two years rather than the statutory minimum of five years. Such review may, as noted, have the effect of greater reliance on reductions through cap-and-trade as AB 32 implementation through other programs evolves. Like the other recommendations we include in this letter, this would further ensure that ARB and California achieves the objectives of AB 32 at the least possible overall cost.

Thank you for the opportunity to present these comments. We look forward to continuing our work with the ARB and all concerned stakeholders to ensure the successful implementation of AB 32.

Very truly yours,

/s/

John W. Busterud

JWB:kp