Pacific Gas and Electric Company™

Mark C. Krausse
Senior Director
State Agency Relations

1415 L Street, Suite 280
Sacramento, CA 95814
(916) 386-5709
nxbz@pge.com

September 19, 2016

Mr. Richard Corey
Executive Officer
California Air Resources Board
1001 I Street
Sacramento, California 95812

Re: Pacific Gas and Electric Company's Comments on the Air Resources Board's Proposed Amendments to the Cap-and-Trade Regulation

Dear Mr. Corey:

Pacific Gas and Electric Company (PG&E) appreciates this opportunity to comment on the Air Resources Board's (ARB's) proposed amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-and-Trade) Regulation.

I. INTRODUCTION

PG&E supports ARB's continued efforts to develop and improve the Cap-and-Trade Regulation. These 2016 amendments are necessarily wide in scope as California prepares for a deeper post-2020 carbon reduction target of 40 percent below 1990 levels by 2030. By making prudent adjustments to Cap-and-Trade, ARB can help ensure that California meets its aggressive greenhouse gas (GHG) emissions reductions goals beyond 2020 while maintaining a vibrant economy.

Fundamentally, the Cap-and-Trade Program should be designed in a way that protects against unreasonable costs, recognizes the investments California utility customers are making in a low carbon energy system, encourages meaningful linkage with other jurisdictions to lower the overall cost of compliance, and provides regulatory certainty to guide investment.

With that thematic framework in mind, PG&E offers the following key comments on the proposed amendments, with more detailed recommendations in sections II-IX below:

- **Electric Allowance Allocation** – PG&E supports the principle of allocating allowances to electric distribution utilities (EDUs) on the basis of customer costs, or "cost burden." Along with many other California EDUs, PG&E has made significant and costly investments in renewable energy and other carbon reducing activities. As the cost of achieving the state's historic climate goals is reflected in more than just allowance prices, PG&E recommends that customer cost burden considerations be extended further than proposed in the amendments, and that investments in emissions-reducing measures continue to be encouraged.

  PG&E also applauds the sunsetting of allowance provisions for legacy contract generators. The removal of this provision appropriately incentivizes legacy contract generators to renegotiate their contracts with EDUs.

- **Gas Allowance Allocation** – PG&E supports continued allocation of allowances to natural gas suppliers with the current cap decline factor, but maintains that the consignment rate should not accelerate for a number of reasons elaborated in this section. Additionally, PG&E recommends that primary facilities that pass through gas to downstream facilities should be treated as intrastate pipelines.

- **Market Design and Linkage**

  Post-2020 Cap Setting – PG&E supports a well-designed market-based mechanism to help reach California's climate goals. Considerable uncertainty exists regarding the cost and feasibility of the 2030 target and targets in interim years. As long as adequate cost containment measures are maintained and the program is examined at regular intervals, PG&E supports the 2030 target. Beyond 2030, mechanisms to control costs and ensure the sustainability of Cap-and-Trade are even more crucial considering the large degree of uncertainty that exists over such an extended time horizon. PG&E does not support reducing the portion of the cap that is allocated or auctioned by placing allowances directly into the APCR to reflect anticipated lower emissions.

  Auction Price Containment Reserve – Cost containment and price stability have been laudable goals of the Cap-and-Trade Program since its inception, and should continue to be emphasized. PG&E is concerned that many of the APCR-related items included in the proposal will constrain the allowance market without providing cost containment or price stability benefits. Moreover, in some circumstances discussed below, PG&E believes ARB's proposal may have the opposite effect, and could lead to sustained higher prices.

  Holding Limits - Addressing modified holding limits in the third compliance period to allow participants to plan for a post-2020 program is necessary and may be one way to provide support for Cap-and-Trade market prices in the short-term without constraining allowance supply. Increasing holding limits is also consistent with the extension of the Program to 2030.

Linkage – Carbon market linkage can ensure that the environmental benefits of the Cap-and-Trade program exist in harmony with a vibrant economy. PG&E supports ARB's proposed linkage with Ontario, and notes that linkages must be well-designed to maintain an affordable and stable market.

Offsets – PG&E applauds ARB's investigation of additional offset protocols, specifically the consideration of REDD+, but notes proposed changes that could unnecessarily constrain or hamper the use of offsets.

- **Clean Power Plan Compliance** – PG&E applauds ARB for being the first state agency in the nation to release a Proposed Compliance Plan for the Federal Clean Power Plan (CPP), and generally supports the proposed amendments to allow the Cap-and-Trade Regulation to support "state measures"-based compliance with the CPP. PG&E also believes the Cap-and-Trade Program can do more to provide for greater "trading readiness" and linkage opportunities in conjunction with the CPP.

- **Voluntary Renewable Energy Program** – The Voluntary Renewable Energy Program (VREP) allowance set aside should be continued as customer programs that utilize VREP allowances are set to ramp up in the coming years, and customer investments in carbon-free energy should continue to be incented.

- **RPS Adjustment** –PG&E remains committed to finding a solution to the Renewables Procurement Standard (RPS) Adjustment that will satisfy the need for accounting accuracy while ensuring California utility customers receive the value of their renewable investments.

- **California Independent System Operator (CAISO) Energy Imbalance Market (EIM) Secondary Emissions Effect** –PG&E recognizes that in some cases it may be possible to determine that in-state demand for renewable resources leads to secondary dispatch of thermal resources outside of California to backfill imported renewable power. In addition to exploring options for capturing secondary emissions from EIM in the Cap-and-Trade Program, ARB should give EIM participants in California credit for overall emissions reductions resulting from the EIM. Any solution to secondary emissions or "leakage" must incorporate and price leakage obligations as part of the EIM optimization so that dispatch remains economic and costs are accurately assigned.

Additional Suggestions and Clarifications – PG&E offers additional comments regarding disclosure of corporate associations, auction cancellation, and auction participation and limitations.

II. ELECTRICAL ALLOWANCE ALLOCATION – CAPTURING THE FULL CUSTOMER COST BURDEN

PG&E strongly supports ARB's proposal to continue allocating allowances to EDUs to help offset costs to utility customers while achieving GHG reductions. PG&E also agrees that "cost burden," or the cost of complying with California's regulations that put a price on carbon emissions, is a sound basis for determining the allowance allocation for each EDU. As proposed, the amendments would allocate to each EDU based on the expected emissions from their GHG-emitting resources in the year 2020. While the direct cost of emissions from serving load is a critical cost element, there are additional costs incurred by California utility customers that must be recognized. This section addresses those costs and a number of other important allowance allocation considerations:

- Cost burden should consider voluntary investments in renewables, energy efficiency investments, and investments in residential behind-the-meter distributed generation.
- Allocation methodology should reflect the post-2020 replacement of Diablo Canyon with zero emission resources.
- Incorporating costs incurred from increased load due to electrification is critical.
- Direct allocation to industrial customers must leave all parties whole.
- The sunsetting of allowance provisions for legacy contract generators appropriately incentivizes legacy contract generators to renegotiate their contracts with EDUs.
- Clarifications on the use of allowance value are appreciated.

A. Section 95892 - Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers – Voluntary Renewables, Energy Efficiency Investments, and Behind-the-Meter Distributed Generation Investments

The current proposal allocates to EDUs based on their expected emissions to serve load. While this may be a reasonable starting point for calculating the carbon costs to which EDU customers will be exposed, it creates a perverse incentive by rewarding higher-emission portfolios a greater number of allowances. As Cap-and-Trade market prices are reflected in California power markets and California's electricity mix is the cleanest energy ever to fuel California's economic growth, PG&E recommends CARB continue its diligent efforts to send market signals to EDU customers that encourage emissions reductions while managing costs.

On June 21, 2016, PG&E joined with labor and environmental partners to announce a Joint Proposal for phasing out PG&E production of nuclear power in California by 2025. All parties are united in the commitment to helping California achieve its clean energy vision. As part of that vision, PG&E has committed to replacing the non-emitting Diablo Canyon resource with a mixture of energy efficiency and renewable generation starting in 2024, and has additionally committed to going beyond the 50-percent RPS mandate beginning in 2031 to a level of 55-percent RPS. [1] PG&E believes its customers should be recognized through additional allowance allocation for making these types of voluntary commitments to invest in renewable and other GHG-free resources.

While adjustments for major changes in EDU portfolios post-2020 is appropriate, PG&E recommends that plans for these adjustments be set in the current rulemaking. This will avoid the

[1] "Joint Proposal for the Orderly Replacement of Diablo Canyon Power Plant with Energy Efficiency and Renewables." Submitted to the California Public Utilities Commission by Pacific Gas and Electric Company. Aug. 11, 2016.

need for another round of amendments to the Cap-and-Trade Regulation to address allowance allocation issues in 2025, which has the benefit of reducing the administrative burden on the ARB and compliance entities, as well as creating increased certainty and encouraging rational market behavior by EDUs and all compliance entities.

Returning to the issue of cost burden, PG&E recommends continuing to recognize the cost burden associated with energy efficiency (EE) investments and the emissions reductions such investments create. These investments were recognized by the allocation methodology used by ARB in 2010 for the 2013-2020 time period, and should be continued post-2020. As the first resource in the State's loading order, continued investment in EE is among the most beneficial and cost-effective means of combating climate change. Moreover, increasing energy efficiency is the primary means of decoupling economic growth from emissions growth. To recognize and encourage these supply-side investments in clean energy, PG&E recommends that ARB provide allocation equivalent to 25 percent of committed energy efficiency load in 2020 at the California marginal natural gas emissions factor. This methodology is consistent with ARB's previous EE allocation methodology, and would result in an aggregate 2020 EDU allocation adjustment of 12.6 million allowances.

Furthermore, PG&E recommends that EDU allowance allocation recognize investments made by EDU customers in clean, behind-the-meter distributed generation (DG) resources, namely rooftop solar. The growth of DG in the state is an important part of gross electricity demand, and rooftop solar installations result in a direct cost to not only installers but to all EDU customers who subsidize DG installations through Net Energy Metering (NEM) rates. Just as ARB recognizes "investments in zero-emitting energy sources"[2] by industrial customers, ARB should recognize investments by residential customers. Using the distributed generation forecast from the California Energy Commission's 2015 Integrated Energy Policy Report (IEPR) Demand Forecast for 2020, recognizing DG investments by EDU customers results in an aggregate allocation adjustment of 11.9 million allowances.

PG&E also recommend that the allocation methodology continue to account for all other non-emitting generation priced-at-market. CARB's proposal to eliminate this portion of the allowance allocation based on size is not adequate justification to shift additional cost burden to EDU customers. This methodology aligns with ARB's previous allocation methodology for resources priced-at-market, and would result in an increase to PG&E's baseline 2020 emitting load by 250 GWh.

B. Increased Electrification Including Transportation Electrification

Increased end-use electrification is expected as California advances toward its climate goals. PG&E appreciates ARB's recognition that there will be increased load as a result of transportation electrification that will necessitate allocation of additional allowances. PG&E recommends this

[2] Air Resources Board. Cap-and-Trade Regulation 2016 Amendments: Setting Post-2020 Emissions Caps. March 29, 2016.

consideration be expanded to increased electrification generally, as all forms of electrification should be equally incented as a means of reducing emissions by using the cleanest possible fuel for the maximum number of end uses.

PG&E recognizes the difficulties associated with measuring, verifying, and reporting the quantity of electricity used to displace more emissions-intensive fuels. While work on this issue will likely need to continue beyond this Cap-and-Trade amendment rulemaking, PG&E suggests that reports and methodologies developed for the Low Carbon Fuel Standard (LCFS) program will be useful in the process. PG&E looks forward to continuing to work with ARB on this important topic.

C. Section 95891 - Direct Allocation to Industrial Covered Entities

PG&E does not object to the transfer of allowances from EDUs to industrial covered entities at this time. However, it is critical that the methodology used to calculate the allowance reduction from EDUs and allowance bestowal to the industrial covered entities leaves both entities whole with regard to allowance value. PG&E looks forward to providing input to staff as that methodology is developed.

D. Section 95870 – Allocation to Legacy Contract Generators for Transition Assistance

PG&E supports the sunsetting of provisions for allowances to legacy contract generators without an industrial counterparty. PG&E believes the sunset will provide incentives to legacy contract generators with non-industrial counterparties to renegotiate their contracts to address GHG matters. In addition, PG&E believes it has received clarification from the courts that its counterparty, Panoche Energy Center ("Panoche") is not a legacy contract generator. That PG&E's power purchase agreement (PPA) with Panoche addresses GHG compliance costs and assigns responsibility for those costs to Panoche was upheld in a published Appellate Court Opinion.[3] ARB's removal of the legacy contract allocation to contract generators without an industrial counterparty is the correct solution to avoid California's customers from compensating Panoche's investors twice for GHG costs as Panoche is already compensated for these costs through the PPA.

E. Sections 95892(d)(3) - Clarified Use of Allowance Values

The proposed amendment clarifies what is meant by the stipulation in the current Cap-and-Trade Regulation that auction proceeds must "benefit ratepayers" by adding that proceeds may be "used to reduce GHG emissions." PG&E appreciates this clarification, and interprets this to mean that auction proceed funds could be used for transportation electrification or any other projects that will provide long-term climate benefits to utility customers.

---

[3] Court of Appeal for the State of California, First Appellate District. Panoche Energy Center LLC v. Pacific Gas & Electric Co., case number A140000. July 1, 2016. Available at: http://www.courts.ca.gov/opinions/documents/A140000.PDF

III. GAS ALLOWANCE ALLOCATION – CONTINUING ALLOCATION AND MAINTAINING PLANNED CONSIGNMENT

A. Continuing Allocation to Natural Gas Suppliers

PG&E as a natural gas supplier utility has a compliance obligation for non-covered natural gas customers. These customers are mostly residential, small commercial and industrial customers. PG&E supports allocating free allowances to protect ratepayers from rising (GHG) costs and offer transition assistance that gradually introduces a price signal across all portions of California's economy in the coming years.

PG&E supports the current allocation methodology based on the 2011 emissions baseline.[4] ARB has not yet identified a post-2020 cap adjustment factor for natural gas; however PG&E recommends ARB use the existing cap adjustment factor declining at a rate of approximately two percent a year.

B. The Current Consignment Requirement for Natural Gas Allowances Should Be Maintained

In the Initial Statement of Reasons (ISOR) supporting the draft Cap-and-Trade amendments, ARB is proposing to expedite the post-2020 consignment requirement for natural gas suppliers.[5] California's natural gas utilities and other stakeholders worked extensively with ARB in the 2013 – 2014 timeframe to derive the current consignment requirement.[6] This consignment requirement is designed to provide an orderly transition to a full carbon price-signal, mitigate market risk, and manage costs for California's natural gas customers.[7] ARB's proposal to accelerate the rate of consignment does not address these documented reasons[8] for a gradual transition, which are still valid today. PG&E recommends that ARB continue with the current consignment rate that was developed three years ago as the most effective way to continue to reduce GHG emissions with minimal impact to California's customers and businesses.

GHG Regulation Should Consider Rate Affordability for Small Natural Gas Customers

PG&E's recommendation to continue the current consignment requirement is based on the core principle of maintaining affordable customer rates. The impact of an accelerated consignment requirement will impact small commercial and industrial customers the most. These customers

---

[4] Section § 95893 - Allocation to Natural Gas Suppliers for Protection of Natural Gas Ratepayers, Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

[5] See page 45 of the August 2016 Initial Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas emissions and Market-Based Compliance Mechanisms

[6] Natural gas suppliers are currently required to consign a minimum percentage of their allocated allowances to auction each year, and this percentage increases by five percent each year, reaching 50 percent in 2020.

[7] See page 66 of the May 2014 Final Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

[8] See page 16 of the September 2013 Initial Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas emissions and Market-Based Compliance Mechanisms

already face a higher cost burden in California. For example, the Public Purpose Program Surcharge rate was 41% of the end-use rates charged to PG&E industrial transmission customers as of January 1, 2016.[9] This is just one example of the many drivers for higher rates in California. Overall rate increase by customer class should be considered by the ARB before taking action that would add additional cost burden.[10]

Increased Carbon Price Signal Will Increase Uncertainty in Customer Rates and May Not Alter Consumption Behavior

ARB's reasoning for increasing the consignment requirement relies on the hypothesis that customers facing direct carbon prices will be incentivized to reduce consumption or move to alternatives to the use of natural gas. PG&E believes that changing consignment requirements is not an effective lever to increase conservation or energy efficiency. Historically, natural gas demand from residential, small commercial and small industrial customers has not been very responsive to retail price signals.[11] PG&E has observed this lack of a statistical relationship between changes in price and demand from smaller customers and reflects this in forward-looking demand forecasts, such as those used for the California Gas Report. Direct incentives for promoting efficiency or conservation may work more effectively.

The proposed change also introduces regulatory uncertainty by suggesting that ARB may suddenly make changes without allowing the time needed for both utilities and consumers to implement more carbon reduction activities. There is also no final decision from the California Public Utilities Commission (CPUC) on how and to which customers the revenue from the consigned allowances will be returned.[12] The delay in current climate credit return (and any potential future delay) creates additional uncertainty in natural gas customer rates.

Accelerated Consignment Will Not Lead to a Level Playing Field

The ISOR additionally cites parity between natural gas utilities and EDUs as a further reason to accelerate consignment for natural gas utilities. However, this fails to recognize the fundamental difference in the assessment of compliance obligations between natural gas utilities and EDUs; the compliance obligation is levied directly on the gas utility based on retail sales, compared to point of generation or import in the electric sector. Electric IOUs and other utilities that are members of CAISO are required to consign allowances in order to prevent market advantage over generators and others in the electricity market. However the same structure does not exist in the natural gas

---

[9] Public Utilities Code sections 890-900 mandate the Public Purpose Program Surcharge which funds state social programs such as the California Alternate Rates for Energy (CARE) program.
[10] PG&E plans to share with the ARB the impact of increased consignment requirement on customer rates.
[11] Bernstein, M.A., Griffin, J. "Regional Differences in the Price-Elasticity of Demand for Energy", National Renewable Energy Laboratory, February 2006 <http://www.nrel.gov/docs/fy06osti/39512.pdf>
[12] The CPUC has granted a limited rehearing of Decision 15-10-032 in the GHG Natural Gas OIR Rulemaking 14-03-003 to discuss California Manufacturers & Technology Association (CMTA)'s application for a rehearing. The Natural Gas IOUs are currently required to suspend any GHG Natural Gas Climate Credit activities.

market; natural gas utilities are the same entities that will be buying back the allowances they consign to the auctions. The market structure for natural gas utilities is more similar to that of the publically owned electric utilities. Additionally, publicly owned utilities in the electric sector are currently allowed to choose whether to consign or surrender their allowances[13]. These differences will persist regardless of the level of consignment for natural gas utilities and therefore reaching 100% consignment sooner will not lead to parity within the Cap-and-Trade Program.

The Transition to a More Sustainable Natural Gas Sector Needs to be Gradual

A third rationale alluded to in the ISOR[14] is transitioning the natural gas sector to a more sustainable future through increased deliveries of renewable natural gas, a goal that PG&E supports. While the state's natural gas suppliers are working to increase deliveries of renewable natural gas (RNG), supply is still too uncertain to replace conventional natural gas at any significant scale. The development of the RNG industry requires a longer transition period. In contrast to the broad availability of renewable electricity, the potential supply of RNG is still uncertain, with large estimated ranges of supply and which are further complicated by competition for feedstock sources with the transportation sector. Finally, the substantially higher cost of RNG will be an even bigger driver of rate increases than carbon costs, meaning that the existing phase-in of consignment will provide some of the "head room" for greater quantities of RNG, while full consignment will in part work against that objective. PG&E believes that greater incentives such as state funding and policies to remove barriers will be more effective to support the growth of RNG.

For these reasons, PG&E recommends continuing the existing consignment requirement for natural gas utilities and looks forward to working with ARB on this issue.

C. "Pass-through" Natural Gas Emissions

Following the February 24, 2016 workshop, PG&E commented that PG&E's customers should not bear the compliance obligation associated with "pass-through" natural gas emissions.[15] PG&E supplies natural gas to a small number of facilities ("primary facilities") that pass-through gas to facilities downstream of the PG&E customer meter ("downstream facilities"). PG&E reports details regarding the Primary Facilities to ARB annually since those facilities receive equal to or greater than 188,500 MMBtu of natural gas in a calendar year, pursuant to 17 CCR § 95122(d)(2)(E). However, the pass-through gas is not measured by a PG&E customer meter, and consequently PG&E cannot determine the accuracy of any reported volume. Regardless, ARB includes the volume of the gas delivered to downstream facilities as part of PG&E's compliance obligation. The compliance and associated costs for emissions associated with the pass-through gas for downstream

[13] Sec. 95892(b) Transfer to Utility Accounts, Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms
[14] See page 45 of the August 2016 Initial Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas emissions and Market-Based Compliance Mechanisms
[15] Pacific Gas and Electric Company. Re: February 24 Workshop on Amendments to the Mandatory Reporting and Cap-and-Trade Regulations. March 11, 2016.

facilities is then borne by PG&E natural gas customers not directly regulated by ARB, an inequitable and inaccurate result. Although the primary facilities receive natural gas from PG&E, they do not have a contractual arrangement with PG&E to pass-through a portion of the gas received to downstream facilities. To remedy this inequity, primary facilities that pass-through gas to the downstream facilities should be treated as intrastate pipelines.

To address this issue, ARB needs to resolve the current conflict between the regulatory definition and guidance regarding the definition of an intrastate pipeline. The MRR defines "Intrastate Pipelines" as, "…Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities that are not considered intrastate pipelines." However, Section 3.1.1 of ARB's February 26, 2016 MRR guidance states:

- *"…When gas is delivered to California end-users by an entity other than a natural gas utility, (e.g., a gas producer), the entity that operates the distribution pipeline delivering the gas is considered the supplier and must report under 95122 as an intrastate pipeline."*
- *"Intrastate Pipelines That Deliver Gas to End-Users: An intrastate pipeline is a distribution pipeline wholly contained within California that is operated by an entity other than a gas utility. Like the natural gas utilities, the operator of an intrastate pipeline that delivers gas to end-users must report pursuant to section 95122(a)(2) of MRR if the total quantity of gas delivered to all entities on their distribution system (i.e., end-users, gas utilities, and/or other pipelines) exceeds the reporting threshold of 10,000 MTCO2e per year. Entities that operate more than one intrastate pipeline must aggregate data from all pipelines in one GHG emissions data report for the entity."*

Primary facilities should report their facility emissions, the metered gas receipts, and the gas supplied to downstream facilities to ARB. Per 17 CCR § 95852(a)(1), ARB should assign a compliance obligation to primary facilities based on emissions associated with metered deliveries of natural gas.

IV. MARKET DESIGN AND LINKAGE – TOWARD AN AMBITIOUS AND SUSTAINABLE PROGRAM

California's goal to reduce emissions to 40 percent of 1990 levels is highly ambitious. As the de facto backstop of California's suite of emissions reduction regulations and policies, Cap-and-Trade plays a critical role in ensuring reductions are reached while providing compliance entities with a flexible means of doing so. A well designing Cap-and-Trade market becomes even more important as California seeks deep emissions reductions without dampening its standing as the world's sixth largest economy.

This section addresses the following proposed market design amendments to the Cap-and-Trade Regulation:

- Post-2020 and Post-2030 Cap Setting
- Modifications to the Auction Price Containment Reserve
- Linkage
- Holding Limits
- Offsets

A. Section 95841 - Post-2020 and Post-2030 Cap Setting

PG&E supports a well-designed Cap-and-Trade Program to help reach California's climate goals. Considerable uncertainty exists regarding the cost and feasibility of the 2030 target and targets in interim years. Assuming adequate cost containment measures are maintained and the program is examined at regular intervals, PG&E continues to support the 2030 target. Beyond 2030, mechanisms to control costs and monitor the feasibility of Cap-and-Trade are even more crucial considering the large degree of uncertainty that exists over such an extended time horizon.

In the near term, ARB should not reduce the annual GHG allowance budget from 2021-2030 by placing allowances in the APCR because 2020 statewide emissions are expected to be lower than the 2020 target. PG&E does not view the success to date in reducing GHG emissions as an over-allocation issue that needs to be addressed. In addition, the continued litigation of the current program and the rigor of the 2030 reduction goal program suggest that the program could become much more constrained in post-2020 years. Meeting the greenhouse gas reduction goals in 2030 and potentially beyond will tighten the program in a way that has not yet occurred.

The role of the APCR is not to address "concerns related to over-allocation of allowance budgets".[16] Rather, the APCR exists as a cost-containment mechanism to provide certainty for market participants. As stated by ARB, "the amount of allowances placed into the APCR for each budget year is set at a level that aims to be large enough to provide effective cost-containment and small enough to avoid constraining the availability of allowances in the market." This proposal would have the opposite effect: reducing the annual GHG allowance budget by transferring a portion of the allowances to the APCR would constrain the allowance market and expose ratepayers to higher costs and price volatility. This is particularly concerning in light of the other proposed market tightening measures discussed in subsection B below and the high APCR price tier proposed by ARB and discussed in subsection C below.

As an alternative approach to perceived over-allocation issues, ARB should raise the holding limit for compliance entities to reflect a 2030 program end date. This will increase demand in the market while allowing compliance entities to plan for compliance in the future program, or hedge their commodity exposure.

[16] Air Resources Board. Proposed Amendments to the California Cap on Greenhouse Gas emissions and Market-Based Compliance Mechanisms ISOR p. 12. August 2, 2016.

B. Section 95911 - Tightening Modifications to the Auction Price Containment Reserve Are Premature

PG&E does not support ARB's proposal to move allowances that remain unsold for 24 months from the auction account to the APCR. The APCR should provide assurances of cost containment and price stability, but this change would impede both of these goals, particularly given the high APCR price tier proposed by ARB.

There are numerous scenarios that could result in market tightening, including continued drought leading to unexpected increases in natural gas-fired generation, continued economic improvement, and future linkages to other carbon markets relying on California's program to defer investments in carbon reducing activities in the linked jurisdiction. If these scenarios occur individually or in combination, or if other regulatory or economic changes increase demand for allowances, utility customers would be exposed to higher costs and price volatility if allowances are not available in the market because they are removed to the APCR. Cost containment and price stability are important program goals because high costs and price volatility could trigger political backlash against the program, resulting in destabilizing intervention.

Additionally, PG&E does not view the soft market exhibited in the last two Cap-and-Trade Auctions to be primarily a result of low demand, but of continuing uncertainty about the future of the program due to legal challenges and the lack of legislation extending the program at the time of those auctions. Therefore, additional tightening measures such as those proposed might be warranted in the future under certain circumstances, but are currently premature.

C. Section 95913 – APCR Reserve Tier Recommendations

As noted above, PG&E opposes transferring unsold allowances to the APCR. However, if ARB decides to change the design to transfer allowances unsold for 24 months to the APCR, the allowances should be transferred to the lowest price tier instead of the highest price tier. Transferring the allowances to the lowest price tier would provide a marginally better measure of cost containment and price stability than ARB's proposal. Cost containment and price stability are important program goals because high costs and price volatility could trigger political backlash against the program, threatening achievement of the State's goals.

Regarding the operation of Reserve tiers post-2020, PG&E supports collapsing the APCR account tiers into a single tier and establishing a fixed price difference between the auction price floor and the APCR account price floor. However, the fixed price difference of $60 proposed by the ARB is too high. In order to provide meaningful cost containment, the price should be set incremental to the lowest APCR price tier. Including significant cost containment measures in the Cap-and-Trade program is fundamental to avoiding economic harm as well as long-term political risk as deeper reductions are sought and allowance prices rise. These circumstances are more likely to arise as emission cap levels drop in the later years of the program.

Another benefit of a smaller step between the auction floor price and the APCR price is that it reduces incentive to manipulate the market to raise prices. In this way, the floor and APCR prices function similarly to a price “collar” on allowances. Establishing a lower APCR price may also alleviate concerns about increasing holding limits, which we elaborate more on below.

D. Section 95920 – Increasing the Holding Limit to Strengthen the Market

The current compliance entity holding limit is based on an assumed program end date of 2020 and should be updated to reflect program continuation through 2030. The existing limit prevents entities with compliance obligations from buying sufficient allowances to plan for post-2020 and engage in legitimate hedging activities. Hedging is an important means to control costs. For entities with large obligations, the holding limit, particularly in the outer years, is too small to adequately hedge. Increasing the holding limit would also help to address perceived over-allocation issues.

PG&E understands that an overly large increase to the holding limit raises concerns about market manipulation to increase prices. However, as explained in our comment on the APCR price tier (Section § 95913), establishing a lower fixed difference between the auction price floor and the APCR price would reduce the incentive to manipulate the market to raise prices. In this way, increasing the holding limit in combination with reducing the step between the auction floor and APCR prices would address a softening allowance market while protecting against market manipulation.

E. Sections 95944 and 95945 – Strong Linkage is Critical to the Future of Cap-and-Trade

Carbon market linkage is crucial to ensuring that California can meet its long-term climate goals while maintaining a healthy economy. As with the market, linkages must be well designed to maintain an affordable and stable market.

PG&E supports ARB’s proposed linkage with Ontario, which will further expand the number of compliance entities that are able to trade allowances, reducing the overall cost of reducing emissions. California should aggressively pursue additional full linkage with other jurisdictions exploring mass-based carbon regulations, such as through the Clean Power Plan. Doing so will further improve the efficiency of the allowance market, and ensure emissions reductions occur not only in California but also more broadly. Full linkage is a very practical way that California’s climate leadership can lead to real and measurable benefits to the atmosphere.

While well-designed linkages are encouraged, ARB’s proposal to create retirement-only agreements could lead to higher allowance prices due to increased external demand. ARB should not engage in retirement-only agreements without measures to protect against potential higher compliance costs for Californians. The process for approving retirement-only agreements should include an assessment that demonstrates no negative impact on California, and require the same level of scrutiny from the Governor’s Office as full linkages.

F. Sections 95973 and 95976 – Amendments Should Facilitate the Offset Market, a Crucial Cost Containment Mechanism

Offsets have an important cost containment function in Californian's Cap-and-Trade Program. In light of an accelerating cap decline, ARB should reexamine the eight percent limit on the use of offsets for compliance. As Governor Brown works to encourage more jurisdictions around the world to reduce emissions through the Under 2 Memorandum of Understanding, it is both consistent with the modifications in the market and with State policy to increase the offset usage limit.

Changes to the regulations should facilitate the growth of an offset market rather than restricting the market. For example, there should be no geographic limit for offsets, and ARB should expand its protocols to allow it to issue out-of-country offsets, subject to proper oversight. Requiring that international offsets be authorized only through linkage is onerous and impedes the development of low cost, high impact offsets which would create large greenhouse gas reductions. As it stands, PG&E expects a shortfall in offset supply that would decrease the important cost containment function of the Regulation's offset provisions. Therefore, PG&E fully supports ARB's consideration of REDD+/sector-based offsets as an opportunity to address offset shortfall.

Additionally, there is an asymmetry between the start and end date of when a project would be considered out of compliance. Specifically, ARB proposes that this time would start when a project takes an action out of compliance but would end when the regulatory body deems it back in compliance. This asymmetry is problematic and may lead to disputes.

There should also be an opportunity to cure in the event of a gap in reporting after the Reporting Period commences to allow offset projects some flexibility as the market develops. PG&E suggests a cure period of one Reporting Period. This could be reassessed when the market is fully developed and as prices stabilize.

V. CPP COMPLIANCE PLAN – GROUNDWORK FOR A WIDER PROGRAM

A. The Proposed Compliance Plan Is Strong but Could Be Improved By Being Made Trading Ready

PG&E applauds the ARB for being the first state agency in the country to put forth a draft Clean Power Plan (CPP) Compliance Plan, and generally supports ARB's proposal to use a state measures plan supported by the existing multi-sector Cap-and-Trade Program. This approach complies with CPP requirements without interfering in the smooth operation of existing California climate programs. PG&E also appreciates ARB's interest in evaluating new market-based programs developed for CPP compliance and efforts to address mass-based trading issues including allocation, allowance tracking, leakage risk, and compliance.

However, ARB could do more to signal its openness to a broader carbon market that could develop through the CPP. In particular, PG&E encourages ARB to take the necessary steps to be designated as trading-ready. In a joint letter on this topic submitted March 28, 2016, PG&E and other stakeholders recommended that ARB incorporate changes to the Cap-and-Trade Program to enable the state to submit a state plan that would be considered trading-ready upon approval. Trading through well-designed linkages offers the potential for significant cost-savings while preserving environmental integrity. Over time, such cost-savings could also facilitate increased GHG reductions. To the extent that potential CPP linkage partners are also WECC states, linkage also creates opportunities to simplify the inclusion of GHG programs in a regional electric market and avoid distortions to least-cost (inclusive of GHG costs) siting and dispatch.

PG&E supports ARB's proposal to utilize the state's full CPP emission target (as recalculated by ARB) in establishing the CPP plan emission glide path. This approach reduces the likelihood of triggering the CPP backstop provisions without undermining environmental integrity; this is because California's existing climate programs already establish economy-wide mass-based emission limits. We also agree that California's many complementary policies are already accounted for by the Cap-and-Trade Program and should not be included as state measures in the CPP plan.

B. Backstop Proposal

PG&E agrees that triggering the CPP backstop is very unlikely given California's existing climate programs, and that nonetheless a backstop mechanism is a required element of a state measures plan. PG&E supports the use of an "affected-EGU-only" cap-and-trade program as the backstop mechanism. Such a program meets EPA backstop requirements, while preserving some flexibility for affected California EGUs in how to achieve California's CPP emission target.

While PG&E generally supports the structure of the backstop proposal, ARB could improve the backstop design in two ways.

First, to provide additional flexibility to affected EGUs in complying with a backstop program, affected EGUs should be allowed to purchase CPP compliance instruments from other mass-based states. The ability to purchase CPP compliance instruments from other states for backstop compliance could reduce costs significantly; this may be particularly important in a future where the backstop is triggered, as in-state emission reductions would clearly have been more difficult to achieve than expected. This additional flexibility for backstop compliance could be provided without affecting economy-wide emissions across the California and linked partner jurisdiction footprint, as affected EGUs would continue to have a separate GHG obligation associated with the multi-sector Cap-and-Trade Program.

Second, PG&E encourages ARB to consider alternative allowance allocation approaches for the backstop program that would use any value associated with backstop allowances for ratepayer, rather than EGU-owner, benefit. For example, similar to the multi-sector Cap-and-Trade Program, ARB could allocate backstop allowances to electric distribution utilities (EDUs) stipulating a 100 percent consignment-to-auction requirement. Recognizing the low likelihood of triggering the backstop, ARB could use a simple approach, such as EDU sales, to allocate these backstop allowances among the EDUs. Such an approach would better protect electric ratepayers and avoid the potential for windfalls associated with free allocations to EGUs that operate in a restructured electricity market.

C. Modeling

California's state agencies make a compelling modeling case that the State's plan is expected to produce CPP compliance under a range of expected futures. However, if additional analysis is conducted in the future before plan submittal to EPA, PG&E encourages the agencies to consider a few modifications aimed at making the analysis more robust and compelling. First, the modeling should use auction reserve prices for California in all years for both stress and reference cases. As the GHG price is the modeling representation of California's proposed measure to comply with the CPP (i.e., the multi-sector Cap-and-Trade Program), using the lowest plausible GHG price is appropriate and could make the results more compelling in the state plan review process. The model would likely still project CPP compliance using these lower California GHG prices. Second, the modeling should use lower GHG prices outside of California that are tied to possible CPP compliance programs rather than California's (higher) auction reserve price. Finally, the agencies should extend the modeling horizon to 2030, or supplement the Plexos analysis with other existing state agency modeling (such as E3 Pathways) that extends through 2030.

VI. VOLUNTARY RENEWABLE ENERGY PROGRAM – ALLOCATION SHOULD CONTINUE AS CUSTOMER PROGRAMS COME ONLINE

The current Cap-and-Trade Regulation sets aside 0.25 percent of the annual allowance budget each year through 2020 for the Voluntary Renewable Energy Program (VREP). A portion of these allowances are retired on behalf of voluntary renewable energy purchasers to ensure that their commitment to renewable energy is reflected under the Cap-and-Trade Program.

ARB proposes not to contribute post-2020 allowances to VREP, in part due to perceived undersubscription in the current program. However, utility Green Tariff Shared Renewables (GTSR) programs that rely on the VREP are just ramping up. As participation increases over the 20-year statutory duration of these programs, it is entirely possible that the full allowance-set aside of .25 percent could be utilized each year. Furthermore, there are other sources of demand for VREP beyond the GTSR program (e.g. POU voluntary renewables programs). The VREP set-aside should be maintained post-2020 by using unallocated post-2020 allowances in recognition of the significant and growing demand by customers to increase California's renewable energy output in a way that decreases the State's overall emissions, contingent upon lowering the default emissions factor from 0.428 $MTCO_2e/MWh$ to a value that more accurately represents avoided emissions from voluntary renewable electricity generation in the 2020-2030 time period.

VII. MAINTAINING THE RPS ADJUSTMENT ALIGNS LANDMARK CALIFORNIA GHG POLICIES AND PROTECTS UTILITY CUSTOMERS

PG&E urges ARB to maintain and strengthen the Renewables Procurement Standard (RPS) Adjustment sections of the Cap-and-Trade and MRR regulations.

The RPS Adjustment is a critical cost mitigation element of the Cap-and-Trade Program. By reducing the compliance obligation of emissions obligations resulting from renewable firmed and shaped electricity being brought from out of state to help meet California's RPS requirement, the program recognizes the above-market investment Californians have made in renewable energy and the associated GHG emissions reductions of the underlying renewable facilities the state's ratepayers helped to finance.

PG&E and a broad array of utility stakeholders who have discussed the RPS Adjustment with ARB staff agree that the RPS Adjustment is problematic as currently addressed in the regulation. Indeed, multiple entities claimed the renewable attributes from the same generation sources in their 2014 emissions reports. However, the utilities have submitted a clear and comprehensive solution to this accounting problem. By reporting Renewable Energy Credit (REC) serial numbers pursuant to the MRR and clarifying the requirements for claiming RPS Adjustment, similar accounting issues can be avoided in the future. The details of the utilities' January 2016 solution to the RPS Adjustment problem can be found in Appendix A of this document.

Removing the RPS Adjustment without providing alternative compensation would have an estimated cost impact of $25 to $70 million a year to California utility customers. The ISOR for the proposed amendments does include an alternative method of compensation to account for the cost of these renewable investments. ARB is to be commended for recognizing that utility customers should not pay an additional carbon cost for their renewable investments.

However, the proposal in its current form does not necessarily provide a level of compensation commensurate with the value lost from the termination of the RPS Adjustment. For one, the value of supplemental allocation will decline over time, while the RPS Adjustment, as a downward shift in compliance obligation, holds or increases its value over time as the cost of allowances increases. Finally, this compensation approach does not consider the lost opportunity for future out of state renewables procurement. ARB's proposed method of alternative compensation would require additional consideration to ensure that California ratepayers receive the full value of their renewable investments.

The RPS Adjustment is a fundamentally good policy in that it recognizes GHG emission reduction investments made by California utility customers and aligns the intent of two of California's landmark GHG programs – the Cap-and-Trade Program and the Renewables Procurement Standard. While implementation of the RPS Adjustment has been problematic, the utilities have provided a unified solution unopposed by any stakeholders that will preserve accounting accuracy and ease implementation. PG&E urges the ARB to reconsider and maintain a strengthened RPS Adjustment.

VIII. CAISO EIM SECONDARY EMISSIONS EFFECT – MORE TIME IS NEEDED TO FIND A SOLUTION THAT MAINTAINS EIM BENEFITS AND AVOIDS UNWARRANTED COSTS TO CUSTOMERS

A. Section 95852 – Compliance Obligation from Secondary Emissions

PG&E recognizes ARB's concern regarding the incomplete accounting of GHG emissions for energy generated in EIM jurisdictions to serve load in California. This is a complex issue that involves balancing efficient energy market design and market optimization benefits with accurate GHG accounting across disparate GHG regulatory regimes.

PG&E is one of many energy sector stakeholders still working to find a solution to resolve this issue and to better understand the overall impact of EIM on emissions. To this end, PG&E suggests that additional opportunities for public input and discussion on this issue should be held after the first Board hearing of the proposed amendments and before the release of 15-day language. For example, CAISO has demonstrated that, to date, the EIM dispatch has lowered overall emissions by increasing exports of in-state renewable generation to displace higher emitting out-of-state resources, such as coal fired plants.[17] EIM participants in California should receive credit for these emissions reductions. The current proposed amendments do not address credit for emissions reductions.

Regarding the issue of secondary emissions, EIM should seek to accurately account for secondary emissions, accurately assign the compliance obligation and cost burden for those emissions, and accurately include the added GHG cost in CAISO's optimization to preserve one of the chief benefits of the EIM, which is the economic dispatch of energy resources.

While this is easier said than done, clearly defining secondary emissions leakage is a good place to start, as a clear definition is necessary for accurately calculating leakage and appropriately assigning the resulting compliance obligation. The definition of leakage must also be defined such that EIM entities outside of California are not subject to California GHG requirements for generating energy to serve load in their jurisdiction. In essence, it must be very clear which emissions are secondary and which are not. The consequence of failing to make the distinction clear could result in the fear or reality of compliance obligations being assigned to out-of-state EIM entities inappropriately, a burden that would impede EIM expansion and likely raise questions about the viability of an expanded balancing area beyond the current CAISO footprint.

PG&E suggests the following definition for EIM leakage for inclusion in Section 95802 of the regulation:

> *EIM leakage refers to greenhouse gas emissions that result from changes to the dispatch of resources in out-of-state EIM jurisdictions to support imports into CAISO. This includes*

[17] California Independent Systems Operator. Energy Imbalance Market GHG Counter-Factual Comparison (Preliminary Results: January-June 2016). August 25, 2016.

> *dispatch changes made to provide energy to serve load in the EIM jurisdictions that could have been served economically by the energy imported into CAISO, as well as dispatch changes to make transmission capacity available to allow out-of-state entities to export energy into CAISO.*

PG&E does not support the current method proposed in the regulation for addressing the secondary emissions issue, as it would not incorporate costs from secondary emissions as part of the EIM optimization, disrupting economic EIM dispatch.

Additionally, it is unnecessary to remove the resource shuffling exemption for economic bids or self-schedules submitted to the EIM. [18] Removing this section could result in market participants being in violation of ARB rules for a market that was developed in consultation with ARB. It is possible to define and price secondary emissions leakage without removing this exemption.

Finally, PG&E notes that ARB will need to reassess EIM leakage obligations if the states where EIM entities are located adopt their own GHG regulations under CPP. This will be necessary to avoid exposing out-of-state generation to double penalties under two different state regimes.

B. Section 95802 – EIM-Related Definitions

A definition for secondary emissions leakage has been provided above. Additionally, PG&E suggests changes to the following EIM-related definitions in the regulation.

> *Electricity Importer* – The definition identifies both generation (in this case, the resource scheduling coordinator) and load (the "EIM purchaser") as Electricity Importers in the CAISO EIM. Defining the importer as both generation and load is confusing and may lead to redundancy or dispute in emissions accounting.
>
> *Imported Electricity* – The language defining electricity dispatched to support EIM transfers to California is vague. PG&E has provided a proposed definition of leakage in our comments on Section 95852.
>
> *EIM Purchaser* - PG&E does not support the EIM purchaser as the point of regulation for EIM dispatch-related leakage. As currently proposed, this method of assigning obligation for EIM dispatch related leakage is not incorporated into the EIM model and, therefore, may result in suboptimal results

IX. Additional Suggestions and Clarifications

A. Section 95833 – Disclosure of Corporate Associations

PG&E seeks clarification on the new provisions for direct corporate associations with individuals who have shared roles, and disclosure exemptions for voluntary registrants. As proposed the new

[18] Sec. 95802(b)(2)(A)(10)

language is not clear regarding whether and how to apply these provisions. As it stands, PG&E may comply with this position by identifying employees that have access to market positions and directing them to document if they have similar access at other entities.

Additionally, PG&E suggests that this section be amended, perhaps in § 95833(a)(6)(B), to indicate that the "direct corporate association" occurs between the entities that are affiliated with the "shared role" individual, and not with the individual himself.

Finally, sections § 95833(b)(1),(2),(3) should be amended to clarify that only disclosure of associations involving a "registered entity" are required; ARB could add the word "registered" to the beginning of each section. This would more clearly align these provisions with the objectives set forth in the ISOR.

B. Section 95911(h) – Auction Cancellation

This section outlines circumstances under which an auction bidding window could be cancelled, specifically if technical systems failures cannot be resolved to meet the requirements for rescheduling an action (e.g. if an auction cannot be rescheduled prior to the expiration of bid guarantees). PG&E suggests ARB provide additional detail on what will occur when an auction is cancelled. At a minimum, ARB will need to schedule another auction to make up for the lost opportunity.

C. Section 95914(c)(1)(B) – Auction Participation and Limitations

PG&E respects the need for auction confidentiality but believes the existing restrictions achieve this end. The new restrictions limiting sharing of the specification of an auction settlement price or range of potential auction settlement prices at which an entity is willing to buy or sell allowances should be removed from the proposed amendments. These additional restrictions may limit participants' ability to transact for allowances through brokers or through the secondary market.

The language could be modified as follows:

(B) Bidding strategy at past our future auctions~~*, including the specification of an auction settlement price or range of potential auction settlement prices at which an entity is willing to buy or sell allowances;*~~

X. CONCLUSION

In conclusion, PG&E continues to support Cap-and-Trade as a program that will help the State meet its aggressive environmental goals while maintaining a healthy economy. PG&E hopes that the ARB will seriously consider the suggestions made herein, and looks forward to continuing to collaborate as Cap-and-Trade extends toward 2030.

Sincerely,

/s/

Mark Krausse
Senior Director
Pacific Gas and Electric Company

Appendix A

January 15, 2016

Ms. Rajinder Sahota

Chief, Climate Change Program Planning & Management Branch

California Air Resources Board

1001 I Street

Sacramento, CA 95812-2828

Re: Potential 2016 Amendments to the Cap-and-Trade Program Concerning the Renewables Portfolio Standard Adjustment

Dear Ms. Sahota:

Los Angeles Department of Water and Power, Modesto Irrigation District, M-S-R Public Power

Agency[19], Pacific Gas and Electric Company, San Diego Gas and Electric Company, Southern California Edison, Southern California Public Power Authority, and Turlock Irrigation District (together, "Utilities") hereby provide input on the Air Resources Board (ARB) December 14, 2015 workshop to discuss potential 2016 amendments to the Cap-and-Trade Program (workshop). These comments are limited to recommended revisions to the Renewables Portfolio Standard (RPS) adjustment sections of the Cap-and-Trade Regulation and Mandatory Reporting Regulation (MRR).

Table of Contents

[19] The M-S-R Public Power Agency is a public agency formed by the Modesto Irrigation District, the City of Santa Clara, and the City of Redding, authorized to acquire, construct, maintain, and operate facilities for the generation and transmission of electric power and to enter into contractual agreements for the benefit of any of its members.

I. Summary of Recommendation

The Utilities urge ARB to maintain and strengthen the RPS Adjustment sections of the Cap-andTrade and MRR regulations. The Utilities propose two simple amendments to ensure the Regulations' existing terms are enforced:

(1) only entities that meet existing criteria for delivered electricity from a renewable specified source, including the Renewable Energy Credit (REC), may report the electricity as specified power; and
(2) no entity may make an RPS Adjustment claim for eligible renewable power properly reported as specified.

Adoption of the Utilities' proposal will better align the characterization and accounting of greenhouse gas (GHG) benefits under the Cap-and-Trade and the RPS Programs, two landmark programs adopted by the Legislature to reduce GHGs. To do so, ARB staff must recognize the role and value that a REC provides under state law, regulation, and commercial practice to accurately track, report, and account for the benefits of eligible renewable generation, including GHG benefits. Without aligning California's two key GHG-reducing programs in this manner the renewable market may face disruption and California ratepayers will be forced to pay tens of millions of dollars in unnecessary emission allowance costs for the same investment made on their behalf to achieve GHG goals.

At the Workshop, diverse stakeholders, including concerned citizens, public and investor-owned utilities, community choice aggregators, and renewable developers, were united in their support for aligning the MRR and Cap-and-Trade regulations with state law, as well as with the established commercial practices of entities engaged in transactions to help the state achieve its ambitious GHG goals through the RPS Program. The Utilities' proposal achieves this alignment. Finally, the use of the REC as a validation tool under the Cap-and-Trade and MRR programs, as it serves under the RPS Program, will simplify the onerous verification process encountered by the ARB in the 2014 reporting year and, critically, will ensure that the GHG benefit from eligible renewable generation is accounted for once, and only once, and by the entity the state Legislature intended to receive such benefit.

II. Because the Legislature Promulgated the RPS and AB 32 Laws to Meet GHG Reduction Goals, ARB Staff Should Align its Regulations to Reflect the Legislature's Intent

At the workshop, ARB Staff did not fully consider stakeholders' suggestions to better align the RPS and Cap-and-Trade programs, noting that the purpose of the RPS Program was to encourage renewable procurement, and not cost-effective GHG reductions.[20] The Utilities implore that Staff reconsider this position, which is inconsistent with both Legislative intent, as described below, but also historical ARB positions.[21] There is no question that the RPS Program and corresponding renewable energy investment by Californians play a critical role in helping California achieve its aggressive GHG reduction goals.

A. The Legislature Explicitly Recognizes that Renewables Reduce GHG Emissions

A key purpose of the RPS program is to reduce GHG emissions. Indeed, the Legislature considers the GHG reduction benefit of renewables alone as sufficient justification for the RPS program. Specifically, Section 399.11(b)[22] of the Public Utilities Code states that procurement of renewable electricity is intended to provide unique benefits to California and lists those benefits, stating "***each of which independently justifies the program***" (emphasis added). Among the benefits enumerated by the Legislature are ***two*** directly related to the GHG reductions.

First, Section 399.11 (b)(1) lists the benefit of "displacing fossil fuel consumption in the state." Clearly, this displacement, and the reduced combustion of those fuels, provides GHG benefits In contrast, renewables are generally non-emitting, and displace fossil emissions that otherwise would service load absent the renewable resource. A second, and more explicit benefit, is identified in Section 399.11 (b) (4): "meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation." Given this unambiguous language, it is clear that the Legislature considers the RPS Program as a mechanism to reduce GHG emissions. In the Legislature's own words, the fact that renewables meet GHG reductions independently justifies the [RPS] Program. Therefore, the ARB should look at this issue from the perspective that the Legislature intended the RPS Program to provide the same GHG reductions sought by AB 32. Where possible, the ARB should consider aligning the two programs. As the Utilities describe below, the ARB can align the two programs through simple changes to existing regulatory language.

[20] *See* RPS Adjustment: Past and Future (December 14, 2015) at p.5 *available at* http://www.arb.ca.gov/cc/capandtrade/meetings/20151214/rpssb350.pdf.

[21] *See* ARB, Climate Change Scoping Plan: A framework for change (2008) at ES-3, ES-13, 11, 16-17, 22, 44-46 (recognizing that the RPS program will reduce emissions of greenhouse gases from the Electricity sector and/or contribute to AB 32 goals). *See also* ARB, First Update to Climate Change Scoping Plan (2014) at 40-41 (recognizing the achievements of the RPS as contributing to climate change goals) and 89 (recognizing the RPS as among "notable groundbreaking climate change initiatives")

[22] This and all other references in these comments to the California Public Utilities Code are to the version of the code as of December 29, 2015.

i. ARB Should Recognize the Value that Firmed and Shaped Transactions Provide Utilities Because the Legislature Allows Firmed-and-Shaped Transactions to Meet GHG Goals

To achieve the RPS Program's GHG-reduction and other goals, the past and current state RPS laws allow utilities to procure renewable energy through out-of-state resources. This long established policy is at the core of the RPS adjustment issue. Among eligible procurement for the RPS are "firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority."[23]

In a typical firming and shaping transaction, a Utility purchases bundled power from an eligible outof-state generator. The underlying electricity associated with the renewable power is re-sold to a third party as "null" power, which is widely understood to be the energy remaining when the REC is stripped from the renewable generator. The Utility retains the REC, which, as described throughout this letter, reflects the renewable and environmental attributes of the generation. The purchaser of the "null" electricity does not own the REC, and therefore cannot claim that the associated renewable generation carries any environmental attribute, including the GHG attribute.

To effectuate a firmed and shaped transaction, the eligible renewable generator or the Utility also enters into a separate transaction to deliver a corresponding amount of electricity as that generated by the eligible out-of-state generator to a California balancing authority (CBA). Under a typical transaction, firmed and shaped power is scheduled to the Utility during an agreed-upon re-delivery period into a CBA. This transaction, combined with the purchased RECs, allows the firmed and shaped electricity to be utilized by the Utility for the purpose of the RPS program.

These transactions benefit Californians by providing utilities and their customers a cost-effective and predictable means to procure and receive zero-emissions energy. The Legislature supported such arrangements through current and past RPS laws as a means to achieve the RPS Program's benefits, including GHG benefits. ARB staff should recognize that these transactions are intended by the Legislature to provide GHG reducing benefits, and those benefits should inure to those that the Legislature intended to receive renewable and environmental attributes.

ii. The ARB Should Recognize the Usefulness of RECs in GHG Reporting Because State Law Recognizes RECs as Providing Renewable and Environmental Attributes

The California Legislature established the REC as the compliance instrument for the RPS program. Specifically, RPS law establishes that the REC is "a certificate of proof, issued through the accounting system established by the Energy Commission… that one unit of electricity was

[23] Public Utilities Code §399.16 (b)(2)

generated and delivered by an eligible renewable energy resource."[24] The Legislature further stated that the REC conveys:

> ***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.[25]

With limited exclusions not pertaining to GHG emissions, the Legislature established that renewable and environmental attributes associated with procured renewable generation is conveyed through the REC instrument. Moreover, the Legislature strengthened the importance of a REC by directing that the California Public Utilities Commission ("CPUC") adopt unmodifiable terms and conditions conveying the RECs to the purchaser of electricity generated by the eligible renewable resource:

> Standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators**. A contract for the purchase of electricity generated by an eligible renewable energy resource, at a minimum, shall include the renewable energy credits associated with all electricity generation specified under the contract**.[26]

As described below, the CPUC subsequently established that the GHG attributes of renewable generation are transferred to the buyer of the REC.

iii. The ARB Should Recognize that the Renewable Market Transacts Under Standard Terms and Conditions Recognizing that the Buyer of the REC Maintains Any Avoided Emissions of GHGs and the Reporting Rights Thereto

In 2008, the CPUC clarified that the GHG attributes of the renewable generation are conveyed to the *buyer* of the REC. The Decision ordered that the REC includes any avoided emissions of "carbon dioxide . . . or any other greenhouse gases that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of global climate change, and the reporting rights to these avoided emissions."[27]

[24] Public Utilities Code §399.12 (h)(1)
[25] Public Utilities Code §399.12(h)(2) (emphasis added)
[26] Public Utilities Code §399.13(a)(4)(C) (emphasis added)
[27] CPUC Decision ("D.") 08-08-028, at Ordering Paragraph 1, available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/86954.pdf. The Decision did not direct the ARB or other

D.08-08-028 did not address the ability to use RECs for the purposes of the Cap-and-Trade program nor did it address the complex reporting issue before the ARB here. However, the California renewables market developed and transacted in reliance on the understanding that GHG attributes associated with the underlying renewable resource, including reporting rights thereto, are transferred to the buyer of the REC.

Further, utilities regulated by the CPUC have transacted for RPS products under certain fixed terms and conditions, and these standard terms and conditions are generally accepted by the broader renewable market. Pursuant to such fixed and standard terms and conditions, the purchaser of the RPS product purchases RECs and the emission reporting rights described above. [28] As a result, many of those firming and shaping transactions of concern to the ARB contain specific commercial terms required by the CPUC providing purchaser the REC and all rights to the "renewable-ness" of the generation, including the right to report the underlying power as zero-emitting.

ARB staff should recognize that the CPUC provided the state's renewable electricity market with certainty and consistency through the establishment of standard terms and conditions concerning ownership of environmental attributes of renewable generation. More recently, the CPUC's Decision 08-08-028 clarified which attributes the RECs convey to the purchaser of RECs, and which attributes do not, and determined that GHG attributes generally transfer to the REC purchaser. [29] ARB regulations and interpretations of regulations that do not provide GHG reporting and other rights to the REC owner will lead to commercial disputes. To convey GHG benefits to entities that sold such benefits or have not purchased rights to such a claim is inconsistent with Legislative intent, CPUC precedent, and commercial practice.

Furthermore, ARB's disregard of the attributes provided by the REC will stymie the development of these transactions. Given the state's increased renewable targets and potential for more stringent GHG goals, ARB should not select a path that could in anyway further constrain efforts to decarbonize the electric sector.

---

regulatory agency to use the RECs for GHG compliance purposes, stating: "Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the definition of the REC, this definition does not create any right to use those avoided emissions to comply with any GHG regulatory program." Note that CPUC standard terms and conditions applicable to the RPS program have conveyed all environmental attributes, broadly defined, to the buyer of renewable power since the inception of the RPS Program. *See* CPUC D. 04-06-014 at Appendix A (defining Environmental Attributes to include any and all "credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Unit(s), and its displacement of conventional energy generation.").

[28] CPUC Decision 08-08-028, at Appendix A-2.

[29] The Legislature established two exceptions to the environmental and renewable attributes : (1) an emissions reduction credit issued pursuant to Section 40709 of the Cal. Health and Safety Code and; (2) any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels. Public Utilities Code § 399.12(h)(2). These exclusions are not relevant to the GHG reporting rights discussed here. [12] Cal. Health and Safety Code § 38562(b)(5).

III. The ARB Should Consider Proposals to Better Align the Cap-and-Trade and RPS Programs Because AB 32 Requires the Harmonization of Such Programs

AB 32 directs the ARB to consider activities such as the RPS Program when promulgating its regulations, among other things, in the Legislatures' direction that the Agency:

A. Consider cost-effectiveness of these regulations:[12] Staff should reconsider its position because any regulation that would require Californians to pay tens of millions of dollars' worth of emissions allowances for activities the Legislature directed and intended to reduce GHG emissions is not cost-effective.
B. Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health:[30] Staff should recognize that transactions subject to the RPS adjustment enable a broad, geographically diverse market for non-emitting resources by allowing out-of-state resources to participate in the RPS program. A broader, western-market for renewables provides broad environmental and economic benefits;
C. Minimize the administrative burden of implementing and complying with these regulations:[31] As described below, the Utilities' proposal to include RECs as a verification tool to justify an entities' right to the environmental attribute of the generation will minimize the administrative burden of importers' eligible renewable claims; and
D. Consult with the CPUC in the development of the regulations as they affect electricity and natural gas providers in order to minimize duplicative or inconsistent regulatory requirements:[32] At a minimum, the ARB should consult with the CPUC concerning its intent to administer the Cap-and-Trade program in a manner which is inconsistent with the RPS Program. As described above, the CPUC implemented the RPS program to standardize terms and conditions such that the purchaser of the REC generally receives GHG benefits associated with the underlying generation. In contrast, the ARB is administering the Cap-and-Trade Program in a manner that would ignore the rights and responsibilities associated with REC ownership.

Therefore, it is incumbent upon ARB staff to recognize that a key purpose of the RPS Program is to achieve the State's GHG goals. The ARB should make all reasonable efforts to harmonize the two programs with respect to the RPS adjustment and direct delivery claims.

[30] *Id.* at § 38562(b)(6).
[31] *Id*.
[32] *Id.* at §38562(f).

IV. The Utilities' Proposal Will Align the Cap and Trade Program with the Renewables Market

The ARB should avoid revising regulations in a manner inconsistent with standard practices concerning ownership of renewable and environmental attributes. As discussed above, the commercial market for compliance RPS products has developed such that ownership of RECs conveys the GHG benefits associated with the eligible renewable product. This right of ownership is established through fixed terms and conditions of power purchase agreements approved by the CPUC prior to their effectiveness. Under such transactions, the owner of the REC controls the right to claim such benefits. Staff's proposal fails to recognize the REC as proper evidence that an importer has the right to claim electricity as renewable not only defies Legislative intent, but all commercial expectations of parties transacting under the California RPS Program.

RECs were developed with the explicit purpose of ensuring ownership and accurate accounting of the renewable attributes of power. Indeed, the construct utilized by the California Legislature and the CPUC has been adopted nationally. According to the United States Environmental Protection Agency (US EPA), "If the physical electricity and the associated RECs are sold to separate buyers, the electricity is no longer considered 'renewable' or 'green.' The REC product is what conveys the attributes and benefits of the renewable electricity, not the electricity itself."[33] Thus, aligning the regulations with REC ownership is consistent with general practices intended to prevent double counting of the benefits of renewable generation.

V. The Utilities' Proposal Will Minimize the Administrative Burden of the ARB and Covered Entities

As discussed at the December workshop, ARB was challenged to accurately account for electricity sector emissions because of competing claims to the GHG benefit of renewable generation. Specifically, the ARB sought to avoid the case whereby one entity claimed null power generated by an eligible renewable resource as directly delivered and another entity claimed the corresponding RECs as an RPS Adjustment.

Adjusting the Cap-and-Trade and MRR to align the regulations with REC ownership will make the program simple to administer and accurate. REC accounting has been standardized in the Western Electricity Coordinating Council (WECC) region by the Western Renewable Energy Generation Information System (WREGIS).

ARB's administration of the RPS adjustment and specified source imports in the Cap-and-Trade and MRR programs, and compliance by reporting entities, could be simplified and streamlined by simply tracking volumes and ownership of RECs through the fully functional WREGIS REC

[33] http://www3.epa.gov/greenpower/gpmarket/rec.htm

accounting system. Verifiers may review whether the entity making the claim to the carbon attribute of the power through either a direct delivery claim or an RPS adjustment has the right to use the REC. This approach would lead to significant cost and resource savings to the ARB, covered entities, and verifiers relative to the onerous and time-consuming verification process encountered in 2014.

VI. The ARB Should Protect the Value of Californians' Investments in Renewable Energy

The Utilities' proposal will ensure Californian ratepayers investments in renewable electricity are not diminished or eviscerated. The Utilities urge the ARB to reconsider this proposal prior to taking any action to modify the Regulation and/or remove the RPS adjustment. At worst, removal of the RPS adjustment will force ratepayers to procure millions of dollars' worth of incremental Cap-andTrade allowances, despite their prior investments in renewable generation. This situation will cause the objectives of the both RPS and Cap-and-Trade Programs to be more costly and difficult to achieve.

Likewise, the continued administration of the RPS adjustment provisions to provide carbon benefits to those entities that have no right to such benefits under commercial contracts and RPS law will only harm utility customers and unjustifiably enrich entities that either sold or did not pay for such a claim. Either outcome is contrary to Legislative intent, commercial practices, and good public policy. Accordingly, the Utilities offer the following recommendations.

VII. Proposed Changes to the Cap-and-Trade Regulation

The Utilities propose revisions to Sections 95852(b)(3) and (b)(4) of the Cap-and-Trade regulation to ensure that the GHG benefits of renewable procurement are provided to those who purchased the environmental attribute of such generation. The Cap-and-Trade Regulation must clarify that only entities with ownership of or permission to use the RECs can claim directly delivered imported renewable energy as specified with a zero emission factor.

The Utilities' revision to Section 95852(b)(3) clarifies that an entity must meet all existing criteria for delivered electricity from a specified source, including REC serial numbers, to report the electricity as specified power. If the entity cannot meet all of the existing criteria, it must report the electricity as unspecified power. Only the entity that owns or has permission to use the REC can claim the carbon benefit under the Cap-and-Trade Program. Similarly, the Utilities propose revising Section 95852(b)(4) to clarify that an RPS adjustment cannot be claimed for electricity that meets the criteria of Section 95852(b)(3). Together, these revisions will ensure the environmental integrity of the Cap-and-Trade program is maintained while protecting the GHG benefits of significant investments made on behalf of California's ratepayers.

Revisions to Section 95852(b)(4) extend the deadline to finalize the RPS adjustment claim to August 1 to align with the CPUC's annual RPS Compliance Report deadline.

The Utilities' proposed revisions to Sections 95852(b)(3) and(b)(4), in strikeout/underline, are as follows:

> Section 95852(b)(3): The following criteria must be met for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emission factor or asset controlling supplier emission factor. If any of the following criteria are not met, then delivered electricity must be reported as unspecified.

(A) ~~Electricity deliveries~~ Delivered electricity must be reported to ARB and emissions must be calculated pursuant to MRR section 95111.

(B) The electricity importer must be the facility operator or have right of ownership or a written power contract, as defined in MRR section 95102(a), to the amount of electricity claimed and generated by the facility or unit claimed;

(C) The electricity must be directly delivered, as defined in MRR section 95102(a), to the California grid; and

(D) If RECs were created for the electricity generated and reported pursuant to MRR, then the REC serial numbers must be reported and verified pursuant to MRR and the electricity importer must report its rights to the RECs (i) as the facility operator with retained rights to the RECs or (ii) by having the right of ownership or contract rights.

Section 95852(b)(4) RPS adjustment. Electricity procured from or generated by an eligible renewable energy resource reported pursuant to MRR must meet the following conditions to be included in the calculation of the RPS adjustment: (A) The electricity importer must have:

1. Ownership of, or contract rights to procure, the electricity and the associated RECs generated by the eligible renewable energy resource; or
2. A contract with an entity subject to the California RPS that has ownership of, or contract rights to, the electricity and associated

RECs generated by the eligible renewable energy resource, as verified pursuant to MRR.

(B) The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity subject to the California RPS, and party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25, and designated as retired for the purpose of compliance with the California RPS program ~~within 45 days of the reporting deadline~~ prior to the annual RPS Compliance Report deadline of August 1 ~~specified in section 95111~~ ~~(g) of MRR for~~ following the year for which the RPS adjustment is claimed.

(C) The quantity of emissions included in the RPS adjustment is calculated as the product of the default emission factor for unspecified sources pursuant to MRR, and the reported electricity generated (MWh) that meets the requirements of this section, 95852(b)(4).

(D) No RPS adjustment may be claimed for ~~electricity generated by~~ the portion of electricity from an eligible renewable energy resource when ~~its~~ this electricity meets all the criteria of section 95852(b)(3) and is claimed as a specified source by an electricity importer ~~is directly delivered~~.

IX. VIII. Proposed Regulatory Changes to Mandatory Reporting Regulation

The Utilities propose revisions to Sections 95111(a)(4) and (g)(3) of the Mandatory Reporting Regulation. Specifically, the revisions to Sections 95111(a)(4) and 95111(g)(3) ensure the requirements for a specified source claim are consistent with the Cap-and-Trade regulation.

Revisions to Section 95111(g)(3) extend the deadline to finalize the RPS adjustment claim from July 15 to August 1 to align with the CPUC’s RPS Compliance Report deadline.

Finally, the Utilities propose moving section 95111(g)(1)(M) to its own Section 95111(g)(2) to reflect the fact that this section is not part of the February 1 registration report. The requirements in Section 95111(g)(1)(M) are related to the

June emission report, not the February registration report and so should be in a separate section.

The Utilities' proposed revisions to Section 95111(a)(4), in strikeout/underline, are as follows:

> Section 95111 (a)(4): *Imported Electricity from Specified Facilities or Units.* The electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity, and meet all of the requirements in section 95852(b)(3) of the cap-and-trade regulation for specified source claims. When reporting imported electricity from specified facilities or units, the electric power entity must disaggregate electricity deliveries and associated GHG emissions by facility or unit and by first point of receipt, as applicable. The reporting entity must also report total GHG emissions and MWh from specified sources and the sum of emissions from specified sources explicitly listed as not covered pursuant to section 95852.2 of the cap-and-trade regulation. The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity and, if applicable, RECs associated with the electricity if sourced from an eligible renewable energy resource from the source through the market path.
>
> (A) Claims of specified sources of imported electricity, defined pursuant to section 95102(a), are calculated pursuant to section 95111(b), must meet the requirements in section 95111(g) and in section 95852(b)(3) of the cap-and-trade regulation, and must include the following information…

…………………………………………………………………………………………

The Utilities' proposed revisions to Section 95111(g)(3), in strikeout/underline, are as follows:

(g) Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment.

Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with ARB pursuant to subsection 95111(g)(1) and by February 1 following each data year to obtain associated emission factors calculated by ARB for use in the emissions data report required to be submitted by June 1 of the same year. If an operator fails to register a specified source by the June 1 reporting deadline specified in section 95103(e), the operator must use the emission factor provided by ARB for a specified facility or unit in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to subsection 95111(g)(2)-(5) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)(5), pursuant to section 95852(b)(4) of the cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to subsection 95111(g)(1) in the emissions data report. Prior registration and subsection 95111(g)(2)-(5) do not apply to RPS adjustments. Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified ~~within 45 days following the emissions data report due date~~ prior to the annual CPUC RPS Compliance Report deadline of August 1.

…………………………………………………………………

The Utilities' proposed revisions to Section 95111(g)(1)(M), in strikeout/underline, are as follows:

~~(M)~~(2) *Requirements for Claims from Eligible Renewable Energy Resources*. Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

~~1~~A. RECs associated with electricity procured from or generated by an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.

~~2~~B. RECs associated with electricity procured from or generated by an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.

~~3~~C. For imported electricity from a specified source which is an eligible renewable energy resource, RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount. If RECs were created for electricity imported from an eligible renewable energy resource but not reported, the imported electricity cannot be claimed as specified.

(~~2~~3) *Emission Factors.* The emission factor published on the ARB Mandatory Reporting website, calculated by ARB according to the methods in section 95111(b), must be used when reporting GHG emissions for a specified source of electricity.

(~~3~~4) *Delivery Tracking Conditions Required for Specified Electricity Imports.* Electricity importers may claim a specified source when the electricity delivery meets any of the criteria for direct delivery of electricity defined in section 95102(a), and one of the following sets of conditions is satisfied:

(A) The electricity importer is a GPE. If the facility/unit is an eligible renewable energy resource then the GPE must have (1) retained rights to the electricity or generation; (2) retained rights to the associated RECs; and (3) report the REC serial numbers associated with the imported electricity pursuant to section 95111(g)(2); or

(B) The electricity importer has a written power contract for electricity generated by the facility or unit. <u>If the facility/unit is an eligible renewable energy resource then the electricity importer must have (1) a right of ownership or contract rights to the associated RECs; and (2) report the REC serial numbers associated with the imported electricity pursuant to section 95111(g)(2)</u>….

(~~5~~<u>6</u>) *Substitute electricity*. Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section.

X. IX. Conclusion

The Utilities are committed to working with ARB staff to more clearly align REC ownership with the ability to claim an RPS adjustment. Doing so will ensure California ratepayers are not forced to fund the procurement of millions of dollars' worth of incremental Cap-and-Trade allowances, despite their prior investments in renewable generation. The RPS adjustment is essential to provide California utility customers the GHG benefit of renewable procurement. We look forward to ongoing discussions about how to resolve this issue for future reporting years and to reduce the burden on both staff and reporting entities.

Sincerely,

/s/

Los Angeles Department of Water and Power

Modesto Irrigation District

M-S-R Public Power Agency

Pacific Gas and Electric Company

San Diego Gas and Electric

Southern California Edison

Southern California Public Power Authority

Turlock Irrigation District