

State of California
Environmental Protection Agency
AIR RESOURCES BOARD

**AMENDMENTS TO THE CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS
AND MARKET-BASED COMPLIANCE MECHANISMS**

FINAL STATEMENT OF REASONS

August 2017

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I. GENERAL

A. Action Taken in This Rulemaking

In this rulemaking, the Air Resources Board (ARB or the Board) is adopting amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (California Cap-and-Trade Regulation or Regulation) to extend the major provisions of the Regulation beyond 2020, to broaden the Program through linkage with Ontario, Canada, and to enhance ARB's ability to implement and oversee the Regulation. The amendments were developed pursuant to the requirements of the California Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB 32). ARB consulted with the Public Utilities Commission in developing the amendments pursuant to Health & Safety Code § 38562(f). The amendments are codified at Subchapter 10 Climate Change, Article 5, sections 95802, 95811, 95812, 95813, 95814, 95830, 95831, 95832, 95833, 95834, 95840, 95841, 95841.1, 95851, 95852, 95852.1, 95852.2, 95853, 95856, 95857, 95858, 95870, 95890, 95891, 95892, 95893, 95894, 95895, 95910, 95911, 95912, 95913, 95914, 95920, 95921, 95922, 95941, 95943, 95972, 95973, 95974, 95975, 95976, 95977, 95977.1, 95978, 95979, 95980, 95980.1, 95981, 95981.1, 95983, 95985, 95987, 95990, 96014, and Appendix C, title 17, California Code of Regulations (CCR) and as new sections 95803, 95835, 95859, 95871, 95944, 95945, new Appendix D, and new Appendix E, title 17, California Code of Regulations.

The Cap-and-Trade Program (Program) is a key element of California's strategy to reduce greenhouse gas (GHG) emissions; it complements other measures to ensure that California cost-effectively meets its established goals for GHG emissions reductions. The proposed amendments would modify existing provisions through the third compliance period of 2018 through 2020 and extend the major elements of the Program beyond 2020 to continue statewide GHG emissions reductions towards the State's 2030 target. With a cap decline of about three and a half percent per year from 2021 through 2030, the proposed Regulation is expected to reduce cumulative statewide GHG emissions between 100 and 200 million metric tons of carbon dioxide equivalent (MMTCO_{2e}) from 2021 through 2030, and the inherent flexibility in the Program will ensure that these reductions are cost-effective.

The regulatory amendments as adopted would:

- Ensure that quantifiable and verifiable GHG emissions reductions are achieved by the Program;
- Continue the allocation of allowances to utilities on behalf of rate-payers;
- Provide for California compliance with the federal Clean Power Plan;
- Clarify compliance obligations for certain sectors;
- Continue Program linkage with Québec, Canada beyond 2020;
- Link the Program with the new cap-and-trade program in Ontario, Canada beginning January 2018; and

- Extend the Program beyond 2020 by establishing new emissions caps, enabling future auction and allocation of allowances, and continuing all other provisions needed to implement the Program after 2020.

Staff and stakeholders have also identified instances where the compliance obligations, allowance allocation, and other Program elements could be applied more consistently and equitably among covered entities, or could be improved to better meet Program goals. Some proposed amendments would streamline Program registration, management of information, auction administration, and issuance of offset credits, and some would modify provisions to improve the consistency and equitability of the Regulation. These amendments would take effect in time for the third compliance period, which covers the 2018-2020 timeframe.

The amendments to the Regulation were initiated with the publication of a notice in the California Notice Register on August 2, 2016 and notice of public hearing scheduled for September 22, 2016.¹ A Staff Report: Initial Statement of Reasons, entitled “Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms” (Staff Report or ISOR), which is incorporated by reference herein, the full text of the proposed regulatory amendments, and other supporting documentation, including documents relied upon, were made available for public review and comment starting on August 5, 2016, running for 45 days through to September 19, 2016.

The Board heard public comment on the regulatory amendments at its September 22 public hearing. During the 45-day and the subsequent 15-day public comment periods, the public submitted comments on the proposed amendments.² The 45-day comment period commenced on August 5, 2016, and ended on September 19, 2016, with additional oral and written comments submitted at the September 22, 2016 Board hearing. The 15-day comment periods occurred from December 21, 2016 to January 20, 2017 and from April 13, 2017 to April 28, 2017.

On July 17, 2017, the Legislature passed, and on July 25, 2017, the Governor signed into law, AB 398 (Chapter 135, Statutes of 2017), which amends certain provisions of AB 32 through 2030, and expressly supports ARB’s authority to continue the Cap-and-Trade Program post-2020. AB 398 also requires certain future modifications to provisions of the Cap-and-Trade Regulation, including provisions related to the Allowance Price Containment Reserve, offsets crediting program, and the setting of a price ceiling. Consistent with legislative direction, following this Board hearing, ARB will

¹ California Air Resources Board. Notice of Public Hearing to Consider Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Posted August 2, 2016. Available online at: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>

² All public comments received on the proposed amendments can be found online at: <http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade13>

initiate a new rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

At a public hearing held on July 27, 2017 the Board approved Resolution 17-21, approving the written responses to environmental comments, making required CEQA and other findings, and adopting the final regulatory amendments. The Resolution also directed the Executive Officer to finalize the Final Statement of Reasons (FSOR) for the regulatory amendments and to submit the final rulemaking package to the Office of Administrative Law for review. The FSOR provides written responses to all comments received on the proposed amendments during the 45-day and 15-day comment periods, during the September 22, 2016 Board hearing, and during the final July 27, 2017 Board hearing.

B. Mandates and Fiscal Impacts to Local Governments and School Districts

The Board has determined that this regulatory action will not create costs or savings, as defined in Government Code sections 11346.5(a)(5) and 11346.5(a)(6), to State agencies or in federal funding to the State. The proposed regulatory action will not create costs and will not impose a mandate on State and local agencies, or school districts. Ten California public universities, several municipal utilities, and one county correctional facility would have a compliance obligation under the amended Regulation. These entities would be required to surrender allowances or offset credits equal to the amount of their GHG emissions during the compliance period as was already required under the current regulation.

Because the regulatory requirements apply equally to all covered entities and unique requirements are not imposed on local agencies, the Board has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies or school districts that is required to be reimbursed pursuant to section 6 of article XIII B of the California Constitution.

C. Consideration of Alternatives to the Proposed Amendments

Staff is required to consider alternatives to the proposed amendments for the Cap-and-Trade Regulation. As discussed in Chapter VII of the Staff Report, staff analyzed the following alternatives to the proposed amendments to the Cap-and-Trade Regulation:

Do not implement the Cap-and-Trade Program (No Project Alternative);
Implement facility specific requirements;
Implement a carbon fee.

For the reasons set forth in the Staff Report, in staff's comments and responses to comments at the Board hearings, and in this FSOR, the Board determined that no alternative considered by the agency would be more effective in carrying out the

purpose for which the regulatory action was proposed, or would be as effective and less burdensome to affected private persons, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provisions of law than the action taken by the Board. Further, none of the options that would have enabled California to meet the goals of reducing GHG emissions to 1990 levels by 2020 and to continue achieving reductions toward the 2030 target of 40 percent below the 1990 level were as cost effective as the proposed Regulation and substantially address the public problem stated in the notice. Staff provides a discussion of each alternative in Chapter VII of the Staff Report for the proposed amendments.

II. MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL

Modifications Provided for in the 15-Day Comment Periods

ARB released a Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (First 15-Day Notice) on December 21, 2016, which placed additional documents into the regulatory record and presented modifications to the regulatory text reflecting public comments made during the 45-day comment period and September 22, 2016 Board hearing as well as additional staff analysis.³

ARB released a second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (Second 15-Day Notice) on April 13, 2017, which placed additional documents into the regulatory record and presented further modifications to the regulatory text reflecting staff analysis and consideration of public comment on the amendments proposed in the First 15-Day Notice.⁴

Non-Substantive Corrections to the Regulation

After the close of the second 15-day comment period, the Executive Officer determined that no additional modifications should be made to the regulations, with the exception of the non-substantive changes listed below.

Section 95802(a): The definition of “Carbon Stock” is moved to be in proper alphabetical order.

³ California Air Resources Board. Notice of Public Availability of Modified Text and Availability of Additional Documents and Information. Posted December 21, 2016. Available online at: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>.

⁴ California Air Resources Board. Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information. Posted April 13, 2017. Available online at: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>.

- Section 95802(a): The text “publicly-owned” is changed to “publicly owned” in the definition of “Public Service Facility.”
- Section 95802(a): The spelling of the word “soluble” is corrected in the definition of “Raw TSS.”
- Section 95802(a): A closing quotation mark is added after “Renewable Portfolio Standard Eligibility” in the definition of “Renewable Energy Credit.”
- Section 95802(a): An extraneous comma is deleted from the definition of “Reporting Period.”
- Section 95812(d): The phrase “until any applicable requirement set forth in section 95812(e) is met” is changed to “until all applicable requirements set forth in section 95835 are met” because the requirements in section 95812(e), which was deleted, were moved to section 95835.
- Section 95830(c)(1)(B): The period at the end of the paragraph is changed to a semicolon.
- Section 95830(c)(1)(G): The period at the end of the paragraph is changed to a semicolon.
- Section 95830(c)(1)(H): The period at the end of the paragraph is changed to a semicolon.
- Section 95830(c)(1)(I): The period at the end of the paragraph is changed to a semicolon.
- Section 95830(c)(1)(J): The period at the end of the paragraph is changed to a semicolon.
- Section 95830(c)(1)(K): The period at the end of the paragraph is changed to a semicolon, and the word “and” is added after the semicolon.
- Section 95830(c)(1)(L): The words “under sections” are changed to “pursuant to section.”
- Section 95830(c)(8)(E): The semicolon at the end of the paragraph is changed to a period.
- Section 95830(d)(1): An extraneous comma is deleted, and the text “in which it” is replaced by “when it first.”
- Section 95830(g)(4)(B)4.: The text “in paragraphs 1. through 3.” is inserted for clarity, and the word “the” is inserted to improve the flow of the text.
- Section 95831(a)(6)(F): The extraneous word “sections” is removed.

Section 95832(d): A comma is inserted to properly offset the parenthetical text “pursuant to section 95803(a).”

Section 95833(a)(1): Unnecessary quotation marks around “corporate association” are removed.

Section 95833(a)(2): Unnecessary quotation marks around “direct corporate association” are removed.

Section 95833(a)(4): Unnecessary quotation marks around “indirect corporate association” are removed.

Section 95833(e)(4): The extraneous period at the end of the paragraph is deleted.

Section 95835(a)(1)(D): The words “either” and “for” are inserted for clarity, and a misplaced comma is deleted.

Section 95835(b)(7): The abbreviation “i.e.” is replaced by “e.g.”

Section 95835(c)(1)(B): The text “report and verify emissions, product, and any other data” is replaced by “report and verify emissions data, product data, and any other data.”

Section 95835(e)(2)(A): The reference to section 95911(d) is removed because it is not relevant.

Section 95841, Table 6-1: The word “Allowances” is replaced by “Allowance” in the title of Table 6-1.

Section 95841, Table 6-2: The word “Allowances” is replaced by “Allowance” in the title of Table 6-2.

Section 95841.1(b)(1)(A): The period at the end of the paragraph is changed to a semicolon.

Section 95841.1(b)(1)(B)3.: The period at the end of the paragraph is changed to a semicolon.

Section 95841.1(b)(1)(C): The period at the end of the paragraph is changed to a semicolon.

Section 95841.1(b)(1)(D): The period at the end of the paragraph is changed to a semicolon.

Section 95841.1(c): A comma is inserted in the definition of the variable “MWh_{VRE}.”

Section 95852(b)(1)(B): Incorrect references to “MRR section 95111(b)(1)” are corrected to “MRR section 95111(b)(2)” in the definitions of the variables “CO₂_{specified}” and “CO₂_{specified-not covered}.” Also, the spellings of the words

“Participating” and “Coordinators” are corrected in the definition of the variable “CO₂e_{specified}.”

Section 95852(b)(1)(D)3.: A period is inserted at the end of the paragraph.

Section 95852(g): A comma is inserted to properly offset the parenthetical text “covered under sections 95811(h) and 95812(c)(3).”

Section 95852(j): A comma is inserted to properly offset the introductory text “From 2013 through the year before which natural gas suppliers are required to consign 100% of allocated allowances to auction pursuant to Table 9-5 or 9-6.”

Section 95852.2(b)(11): The word “and” is deleted from the end of the paragraph.

Section 95852.2(b)(12): The period at the end of the paragraph is changed to a semicolon.

Section 95852.2(b)(13): The period at the end of the paragraph is changed to a semicolon, and the word “and” is added after the semicolon.

Section 95853(c): The spelling of the word “any” is corrected.

Section 95856(h)(1)(D): The word “sections” is changes to “section.”

Section 95856(h)(3): An extraneous comma is deleted.

Section 95859(e)(8): The acronym “CCP” is corrected to “CPP.”

Section 95870(d)(1): The reference to section “95892(b)(2)(A)” is corrected to section “95892(b).”

Section 95870(f): In three instances, the text “publicly-owned” is changed to “publicly owned.”

Section 95870(h): The reference to section “95893(b)(1)(B)” is corrected to section “95893(b).”

Section 95871(c)(1): The reference to section “95892(b)(2)(A)” is corrected to section “95892(b).”

Section 95871(e): In two instances, the text “publicly-owned” is changed to “publicly owned.”

Section 95871(g): The reference to section “95893(b)(1)(B)” is corrected to section “95893(b).”

Section 95890(k): The word “an” is changed to “a.” A comma is moved so that it precedes the text “or if a covered entity or opt-in covered entity previously eligible for allocation pursuant to section 95870(e) ceased to operate under an activity listed in Table 8-1” and properly offsets this parenthetical text. Also the redundant text “fulfill the requirement to” is deleted.

Section 95890(k)(A): The paragraph number is corrected from “(A)” to “(1).”

Section 95890(k)(B): The paragraph number is corrected from “(B)” to “(2).”

Section 95890(k)(2): The spelling of the word “Officer” is corrected.

Section 95890(k)(C): The paragraph number is corrected from “(C)” to “(3).”

Section 95890(k)(D): The paragraph number is corrected from “(D)” to “(4).”

Section 95891(a)(1): The word “section” is added.

Section 95891(b)(1): The text “pursuant to 95856(h)(1)(D) and 95856(h)(2)(D)” is changed to “pursuant to sections 95856(h)(1)(D) and (h)(2)(D)” in the definition of the variable “TrueUp_t.”

Section 95891(b)(1): A semicolon is inserted prior to the final word “and” in the definition of the variable “AF_{a,t-2}.”

Section 95891(b), Table 9-1: In the table entry for “Fluid Milk Product Processing (vintage 2019 allocation and beyond),” an extraneous comma is deleted from the “Benchmark Units” column.

Section 95891(b), Table 9-1: In the table entry for “Buttermilk Powder Processing (through vintage 2018 allocation),” a closing parenthesis is added in the “Activity (a)” column.

Section 95891(b), Table 9-1: In the table entry for “Dairy Product Solids for Animal Feed Processing (through vintage 2018 allocation),” a closing parenthesis is added in the “Activity (a)” column.

Section 95891(c): The text “MMBtus” is changed to “MMBtu” in the definition of the variable “F_{Consumed}.”

Section 95891(c): The text “MWhs” is changed to “MWh” in the definition of the variable “e_{Sold}.”

Section 95891(c)(2): The word “Energy-based” is changed to “Energy-Based,” and the text “under 95891(c)(2)” is replaced by “pursuant to section 95891(c)(2).”

Section 95891(c)(2)(A): In the equation for “A_{a,t},” the variable “e_{sold,est}” is changed to “e_{Sold,est}” (capitalizing the “s”).

Section 95891(c)(2)(B): The word “section” is inserted in the first sentence.

Section 95891(c)(2)(B): In the equation for “InitialAllocation_t,” the variable “e_{sold,t-2}” is changed to “e_{Sold,t-2}” (capitalizing the “s”).

Section 95891(c)(2)(B): The text “MMBtus” is changed to “MMBtu” in the definition of the variable “F_{t-2},” which appears in the equation for “InitialAllocation_t.”

Section 95891(c)(2)(B): In the equation for “ BE_{t-2} ,” the variable “ $e_{sold,t-2}$ ” is changed to “ $e_{Sold,t-2}$ ” (capitalizing the “s”).

Section 95891(c)(2)(B): The text “MMBtus” is changed to “MMBtu” in the definition of the variable “ F_{t-2} ,” which appears in the equation for “ BE_{t-2} .”

Section 95891(c)(2)(D): In the equation for “ BE_t ,” the variable “ $e_{sold,t}$ ” is changed to “ $e_{Sold,t}$ ” (capitalizing the “s”).

Section 95891(c)(2)(D): The text “MMBtus” is changed to “MMBtu” in the definition of the variable “ F_t ,” which appears in the equation for “ BE_t .”

Section 95891(c)(3): In the first sentence, the word “that” is replaced by “in which,” and the text “set forth in 95891(c)(3)(A) through 95891(c)(3)(C)” is replaced by “set forth in sections 95891(c)(3)(A) through (c)(3)(C).”

Section 95891(c)(4): In two instances, the text “under 95891(c)” is replaced by “pursuant to section 95891(c),” and in one instance, the text “under section 95891(c)” is replaced by “pursuant to section 95891(c),”

Section 95891(d)(1): An opening parenthesis is added before the paragraph number “1.”

Section 95891(d)(1): Section 95891(c)(2)(B): In the equation for “ A_t ,” the variable “ $F_{consumed}$ ” is changed to “ $F_{Consumed}$,” the variable “ $Q_{purchased}$ ” is changed to “ $Q_{Purchased}$,” the variable “ Q_{sold} ” is changed to “ Q_{Sold} ,” the variable “ e_{sold} ” is changed to “ e_{Sold} ,” and the variable “ $B_{electricity}$ ” is changed to “ $B_{Electricity}$.”

Section 95891(d)(1): In its definition, the variable “ $F_{consumed}$ ” is changed to “ $F_{Consumed}$ ” (capitalizing the “c”).

Section 95891(d)(1): The text “MMBtus” is changed to “MMBtu” in the definition of the variable “ $F_{Consumed}$ ” (capitalizing the “c”).

Section 95891(d)(1): In its definition, the variable “ $Q_{purchased}$ ” is changed to “ $Q_{Purchased}$ ” (capitalizing the “p”).

Section 95891(d)(1): In its definition, the variable “ Q_{sold} ” is changed to “ Q_{Sold} ” (capitalizing the “s”).

Section 95891(d)(1): In the definition of the variable “ e_{Sold} ,” the text “MWhs” is changed to “MWh” (capitalizing the “s”).

Section 95891(e): The text “opt-in entity” is changed to “opt-in covered entity.”

Section 95891(e)(2): A closing parenthesis is added after the paragraph number “2.”

Section 95892(a)(2): An extraneous dash is deleted.

Section 95892(b)(2)(A): The text “pursuant to 95931(d)” is corrected to “pursuant to section 95831(a)(6).”

Section 95892(d)(5): An extraneous comma is deleted.

Section 95892(d)(6): The text “natural gas supplier” is replaced by “EDU.”

Section 95892(e): The text “June 30 of” is inserted to clarify that the use of allowance value report must be submitted by June 30 of each calendar year after 2014.

Section 95892(e)(3): The extraneous word “to” is deleted.

Section 95893(b)(1)(B): The text “pursuant to 95931(d)” is corrected to “pursuant to section 95831(a)(6).” There is no section 95931, and the provisions referred to are contained in section 95831(a)(6).

Section 95893(d)(5): Two extraneous commas are deleted.

Section 95893(e): The text “June 30 of” is inserted to clarify that the use of allowance value report must be submitted by June 30 of each calendar year after 2014.

Section 95893(e)(3): The reference to “section 95892(e)” is corrected to “section 95893(e).”

Section 95894(c): The period at the end of the definition of “ $c_{a,t}$ ” is changed to a semicolon.

Section 95894(c): The word “years” is replaced by “year” in the definition of “ $AF_{lc,t}$.”

Section 95894(c): An extraneous comma is deleted from the variable “ $EEm_{lc,t-2}$ ” in the definition of that variable, which appears in the equation for “ $TrueUp_t$.”

Section 95894(c)(2): The text “For legacy contract generators with an industrial counterparty, subject to 95894(c) but not covered in 95894(c)(1), the following equations apply:” is changed to “For legacy contract generators with an industrial counterparty subject to section 95894(c), but not covered by section 95894(c)(1), the following equations apply:”

Section 95913(e): A period is inserted after the heading of this section.

Section 95913(i)(3)(C): The extraneous text “and return” is deleted.

Section 95921(d)(4): The acronym “ECHA” is replaced by “exchange clearing holding account.”

Section 95943(b): The text “Covered or opt-in entities” is replaced by “Covered or opt-in covered entities.”

Section 95973(b)(1)(A)3.: The word “of” is inserted.

Section 95979(b)(3): The spelling of the word “Secretariat’s” is corrected.

Section 95980(c): A period is added to the end of the section.

Section 95990(a): The duplicate section number “(a)” is deleted.

Section 95990(a)(1)(B): The extraneous word “section” is deleted, and the text “section 95990(i)” is replaced by “the Program for Recognition of Early Action Offset Credits.”

Section 95990(a)(3)(B): The extraneous word “section” is deleted.

Section 95990(a)(3)(B)2.: The extraneous word “section” is deleted.

Section 95990(a)(3)(B)3.: The extraneous word “section” is deleted.

Section 95990(a)(4)(B): The extraneous word “section” is deleted.

Section 95990(a)(4)(C): The extraneous word “section” is deleted.

Section 96014(c): The reference to “section 95835(f)(1)(D)(1)” is changed to “section 95890(k).”

Appendix D: In the heading of the “Annual CPP Glidepath Target” column, the “#” used to call out the footnote to the table is deleted because it is not relevant to that column.

Appendix D: The entry in the “CPP Backstop Trigger” column for the time period 2021 through 2022 is changed from “55” to “55.0.”

The above described modifications constitute non-substantial changes to the regulatory text because they more accurately reflect the numbering of sections, correct spelling and grammatical errors, and correct citations, but do not materially alter the requirements, rights, responsibilities, conditions, or prescriptions of the proposed rulemaking action.

Additional Non-Substantive Corrections to the Regulation

Section 95802(a): In the definition for “Tomato soluble solids,” the text “‘Processing Tomato Advisory Board (PTAB) Inspection Procedures – Soluble Solids: Using a Digital Refractometer’ (2014)” is replaced by the text “‘Inspection Procedures’ (2014) for Soluble Solids Testing – Digital Refractometer, as published by the Processing Tomato Advisory Board (PTAB).” Also in this definition, the text “‘Processing Tomato Advisory Board (PTAB) Inspection Procedures’ (2014)” is replaced by the text “‘Inspection Procedures’ (2014) for Soluble Solids Testing – Digital Refractometer, as published by the Processing Tomato Advisory Board (PTAB).” These changes make the citations to the PTAB 2014 inspection procedures document internally consistent and consistent with the definition in the Mandatory Reporting Regulation.

Section 95941: The text “after public notice and opportunity for public comment in accordance with the Administrative Procedure Act” is changed to “after complying with relevant provisions of the Administrative Procedure Act”.

Section 95945(a): The text “after public notice and opportunity for public comment in accordance with the Administrative Procedure Act” is changed to “after complying with relevant provisions of the Administrative Procedure Act”.

Section 95977.1(b)(3)(R)8.: The text “of the determination” is added to the end of the paragraph.

The above described modifications constitute non-substantial changes to the regulatory text because they more accurately reflect the only legally tenable interpretation of the text and correct citations, but do not materially alter the requirements, rights, responsibilities, conditions, or prescriptions of the proposed rulemaking action.

III. DOCUMENTS INCORPORATED BY REFERENCE

The Cap-and-Trade Regulation adopted by the Executive Officer incorporates by reference the following documents:

California Air Resources Board (2017). Method to Determine the Boric Oxide Equivalent in Borate Products.

Processing Tomato Advisory Board (2014). Processing Tomato Advisory Board Inspection Procedures.

U.S. Department of Agriculture (2005). Agriculture Shipping Point and Market Inspection Instructions for Pistachios in the Shell.

These documents were incorporated by reference because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in the California Code of Regulations. In addition, some of the documents are copyrighted, and cannot be reprinted or distributed without violating the licensing agreements. The documents are lengthy and highly technical test methods and engineering documents that would add unnecessary additional volume to the regulation. Distribution to all recipients of the California Code of Regulations is not needed because the interested audience for these documents is limited to the technical staff at a portion of reporting facilities, most of whom are already familiar with these methods and documents. Also, the incorporated documents were made available by ARB upon request during the rulemaking action and will continue to be available in the future.

IV. SUMMARY OF COMMENTS MADE DURING THE 45-DAY COMMENT PERIOD AND SEPTEMBER 22, 2016 BOARD HEARING AND AGENCY RESPONSES

Chapter IV of this FSOR contains all comments submitted during the 45-day comment period and the September 22, 2016 Board hearing that were directed at the proposed amendments or to the procedures followed by ARB in proposing the amendments, together with ARB's responses. The 45-day comment period commenced on August 5, 2016, and ended on September 19, 2016, with additional comments submitted at the September 22, 2016 Board hearing on the proposed amendments.

ARB received 95 letters on the proposed amendments (not including duplicates) during the 45-day comment period and 9 written comments at the Board hearing. In addition, 68 commenters gave oral testimony at the September 2016 Board hearing. To facilitate use of this document, comments are categorized into sections, and are grouped by response wherever possible.

Table IV-1 below lists commenters that submitted oral and written comments on the proposed amendments during the 45-day comment period and at the September 22, 2016 Board hearing, identifies the date and form of their comments, and shows the abbreviation assigned to each.

Note that some comments which follow were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>. Transcripts for any verbal testimony presented is available here: <https://www.arb.ca.gov/board/mt/2016/mt092216.pdf>.

A. LIST OF COMMENTERS

Table IV-1

Abbreviation	Commenter
3DEGREES	Syche Cai, 3Degrees Group, Inc. Written Testimony: 09/29/2016
AGCOUNCIL	Rachael O'Brien, Agricultural Council of California Written Testimony: 09/19/2016
AGCOUNCIL2	Rachael O'Brien, Agricultural Council of California Oral Testimony: 09/22/2016
AGMETHANE	Patrick Wood, Ag Methane Advisors Written Testimony: 09/19/2016
AHTNA	Michelle Anderson, Ahtna, Incorporated Written Testimony: 09/19/2016
AIRLIQUIDE	Dwayne Phillips, Air Liquide Large Industries US LP Written Testimony: 09/19/2016
AIRPRODUCTS	Keith Adams, Air Products and Chemicals Written Testimony: 09/19/2016

Abbreviation	Commenter
BLOOMENERGY	Alia Schoen, Bloom Energy Written Testimony: 09/19/2016
BLOOMENERGY2	Erin Grizard, Bloom Energy Oral Testimony: 09/22/2016
BLUESOURCE	Joshua Strauss, Blue Source Written Testimony: 09/19/2016
BPA	Alisa Kaseweter, Bonneville Power Administration Written Testimony: 09/19/2016
CAISO	Andrew Ulmer, California Independent System Operator Corporation Written Testimony: 09/19/2016
CALBIO	Neil Black, California Bioenergy Board Hearing Written Testimony: 09/28/2016
CALBIO2	Neil Black, California Bioenergy Oral Testimony: 09/22/2016
CALCHAMBERCOMMERCE	Amy Mmagu, California Chamber of Commerce Written Testimony: 09/16/2016
CALCHAMBERCOMMERCE2	Amy Mmagu, California Chamber of Commerce Oral Testimony: 09/22/2016
CALMUNIUTILASSOC	Dan Griffiths, California Municipal Utilities Association Oral Testimony: 09/22/2016
CALPINE	Barbara McBride, Calpine Corporation Written Testimony: 09/19/2016
CBD	Brian Nowicki, Center on Biological Diversity Written Testimony: 09/19/2016
CBE	Julia May, Communities for a Better Environment Oral Testimony: 09/22/2016
CBLMARKETS	Nathan Rockliff, CBL Markets Written Testimony: 09/19/2016
CCEEB	Mikhael Skvarla, California Council for Environmental and Economic Balance Board Hearing Written Testimony: 09/28/2016
CCEEB2	Mikhael Skvarla, California Council for Environmental and Economic Balance Oral Testimony: 09/22/2016
CCPC	Shelly Sullivan, Climate Change Policy Coalition Written Testimony: 09/19/2016
CCPC2	Shelly Sullivan, Climate Change Policy Coalition Oral Testimony: 09/22/2016
CEJA	Amy Vanderwarker, California Environmental Justice Alliance Written Testimony: 09/19/2016
CEJA2	Amy Vanderwarker, California Environmental Justice Alliance Oral Testimony: 09/22/2016

Abbreviation	Commenter
CENTRACEPOENV	Brent Newell, Center on Race, Poverty & the Environment Oral Testimony: 09/22/2016
CENTRACEPOENV2	Sofia Parino, Center on Race, Poverty & the Environment Oral Testimony: 09/22/2016
CENTRACEPOENV3	Juan Florez, Center on Race, Poverty & the Environment Oral Testimony: 09/22/2016
CENTRACEPOENV4	Madeline Stano, Center on Race, Poverty & the Environment Oral Testimony: 09/22/2016
CENTRACEPOENV5	Caroline Farrell, Center on Race, Poverty & the Environment Oral Testimony: 09/22/2016
CENTRACEPOENV6	Valerie Gorospe, Center on Race, Poverty & the Environment Oral Testimony: 09/22/2016
CGDEV	Jonah Busch, Center for Global Development Written Testimony: 09/14/2016
CHEVRON	Julia Bussey, Chevron USA Oral Testimony: 09/22/2016
CLEANEN	Harrison Clay and Todd Campbell, Clean Energy Fuels Corporation Written Testimony: 09/16/2016
CLIMACTRESERV	Rachel Tornek, Climate Action Reserve Written Testimony: 09/19/2016
CLIMATETRUST	Sheldon Zakreski, The Climate Trust Written Testimony: 09/19/2016
CMCA	Andre Templeman, Carbon Market Compliance Association Written Testimony: 09/15/2016
CMCA2	Andre Templeman, CMCA Oral Testimony: 09/22/2016
CMTA	Michael Shaw, California Manufacturers & Technology Association Written Testimony: 09/19/2016
CMTA2	Michael Shaw, California Manufacturers & Technology Association Oral Testimony: 09/22/2016
CODA	Charles Purshouse, Compliance Offset Developers Association Written Testimony: 09/19/2016
COMMBETTENV	Shana Lazerow, Communities for a Better Environment Oral Testimony: 09/22/2016
COMMBETTENV2	Laura Gracia, Communities for a Better Environment Oral Testimony: 09/22/2016
CONSERVANCY	Michelle Passero, The Nature Conservancy Written Testimony: 09/19/2016

Abbreviation	Commenter
CONSERVANCY2	Louis Blumberg, The Nature Conservancy Oral Testimony: 09/22/2016
COVANTA	Michael Van Brunt, Covanta Written Testimony: 09/19/2016
CRS	Todd Jones, Center for Resource Solutions (CRS) Written Testimony: 09/19/2016
CSCME	John Bloom, Coalition for Sustainable Cement Manufacturing & Environment Written Testimony: 09/19/2016
CULLENWARD	Danny Cullenward, Private Individual Written Testimony: 09/19/2016
EARTHINNOVATION	Daniel Nepstad, Earth Innovation Institute Written Testimony: 09/19/2016
EARTHINNOVATION2	Jack Horowitz, Earth Innovation Institute Oral Testimony: 09/22/2016
EDF	Erica Morehouse, Environmental Defense Fund Written Testimony: 09/19/2016
EDF2	Erica Morehouse, Environmental Defense Fund Oral Testimony: 09/22/2016
EIMENTITIES	Christine Kirsten, EIM Entities Written Testimony: 09/19/2016
EJAC	Environmental Justice Advisory Committee Written Testimony: 8/30/2016
EJAC2	Katie Valenzuela Garcia, Environmental Justice Advisory Committee Oral Testimony: 09/22/2016
EJAC3	Martha Dina Argüello, Environmental Justice Advisory Committee Oral Testimony: 09/22/2016
EPUC	Evelyn Kahl, Alcantar & Kahl LLP on behalf of Energy Producers and Users Coalition Written Testimony: 09/15/2016
ETHANOL	Jeffrey Adkins, Sierra Research Written Testimony: 09/19/2016
FINITECARBON	Sean Carney, Finite Carbon Written Testimony: 09/19/2016
FIRSTENV	James Wintergreen, First Environment, Inc Written Testimony: 09/19/2016
FOODPROCESSORS	John Larrea, California League of Food Processors Written Testimony: 09/19/2016
FOODPROCESSORS2	John Larrea, California League of Food Processors Oral Testimony: 09/22/2016

Abbreviation	Commenter
FOODWATER	Rebecca Claasen, Food and Water Watch Oral Testimony: 09/22/2016
FORESTTRENDS	Gus Silva-Chavez, Forest Trends Written Testimony: 09/19/2016
GAIA	Monica Wilson, Global Alliance for Incinerator Alternatives Written Testimony: 09/19/2016
GAIA2	Monica Wilson, Global Alliance for Incinerator Alternatives Oral Testimony: 09/22/2016
GAZMETRO	Vincent Pouliot, Gaz Metro Limited Partnership Written Testimony: 09/19/2016
GLASSPACKAGING	Lynn Bragg, Glass Packaging Institute Written Testimony: 09/19/2016
GLASSPACKAGING2	Jason Ikerd, Edelstein, Gilbert, Robson & Smith on behalf of the Glass Packaging Institute Oral Testimony: 09/22/2016
GRAPHICPACKAGING	Bill Buchan, Graphic Packaging International Written Testimony: 09/16/2016
GRAPHICPACKAGING 2	Bill Buchan, Graphic Packaging International Written Testimony: 09/16/2016
GRAPHICPACKAGING 3	Bill Buchan, Graphic Packaging International Written Testimony: 09/16/2016
GRAPHICPACKAGING 4	Bill Buchan, Graphic Packaging International Written Testimony: 09/16/2016
HERRERA	Gloria Herrera, Private Individual Oral Testimony: 09/22/2016
ICE	Stephen McComb, Intercontinental Exchange (ICE) Futures US and ICE Clear Europe Written Testimony: 09/19/2016
IEP	Amber Blixt, Independent Energy Producers Association Written Testimony: 09/14/2016
IETA	Katie Sullivan, International Emissions Trading Association Written Testimony: 09/19/2016
IETA2	Lenny Hochschild, IETA / Evolution Markets Oral Testimony: 09/22/2016
JOHNSMANV	Bruce Ray, Johns Manville Oral Testimony: 09/22/2016
JOINTCCAS	C.C. Song, Community Choice Aggregators Written Testimony: 09/19/2016
JOINTENVJUSTICE	Brent Newell, Joint Environmental Justice and Environmental Organizations Written Testimony: 09/19/2016
JOINTGASUTILS	Mark Krausse, Gas Utility Group Written Testimony: 09/19/2016

Abbreviation	Commenter
JOINTUTILITIES	Adam Smith, Joint Utilities Group Written Testimony: 09/19/2016
JOSEPHFARMS	Mike Gallo, Joseph Gallo Farms Written Testimony: 09/16/2016
KIMBERLY-CLARK	Dell Majure, Kimberly-Clark Written Testimony: 09/19/2016
LADWP	Jodean Giese, Los Angeles Department of Water & Power Written Testimony: 09/19/2016
LADWP2	Nancy Sutley, LA Department of Water and Power Oral Testimony: 09/22/2016
LADWP3	Cindy Parsons, LA Department of Water and Power Oral Testimony: 09/22/2016
LEADERCOUNSEL	Sandra Vasquez, Leadership Counsel for Justice and Accountability Oral Testimony: 09/22/2016
LEADERCOUNSEL2LEADERCOUNSEL2	Phoebe Seaton, Leadership Counsel for Justice and Accountability Oral Testimony: 09/22/2016
LIMACOSTA	Francisca Oliveira de Lima Costa, Private Individual Oral Testimony: 09/22/2016
LOCKHEED	Kraig Kurucz, Lockheed Martin Space Systems Company Written Testimony: 09/19/2016
LOPES	Ludovino Lopes, Private Individual Oral Testimony: 09/22/2016
LOSSY	Frank Lossy, Private Individual Written Testimony: 09/16/2016
MARQUEZ	Anabel Marquez, Private Individual Oral Testimony: 09/22/2016
MEINZEN	Stacey Meinzen, Private Individual Written Testimony: 09/18/2016
MENDEZ	Francisco Mendez, Private Individual Oral Testimony: 09/22/2016
MODESTOID	Gary Soiseth, Modesto Irrigation District Written Testimony: 09/19/2016
MODESTOID2	Sean Neal, Modesto Irrigation District Oral Testimony: 09/22/2016
M-S-R	Martin R. Hopper, M-S-R Public Power Agency Written Testimony: 09/19/2016
MWD	Janet Bell, Metropolitan Water District Written Testimony: 09/19/2016
NAIMA	Angus Crane, North American Insulation Manufacturers Association Written Testimony: 09/19/2016

Abbreviation	Commenter
NCPA	Susie Berlin, Northern California Power Agency Written Testimony: 09/19/2016
NCPA2	Susie Berlin, Northern California Power Agency and MSR Public Power Oral Testimony: 09/22/2016
NFCRC	Erin Grizard, National Fuel Cell Research Center Board Hearing Written Testimony: 09/28/2016
NRDC	Alex Jackson, Natural Resources Defense Council Written Testimony: 09/19/2016
NRDC2	Alex Jackson, Natural Resources Defense Council Oral Testimony: 09/22/2016
NWF	Barbara Bramble, National Wildlife Federation Written Testimony: 09/02/2016
OFFICERATEPAYERA DVCT	Diana Lee, Office of Ratepayer Advocates Written Testimony: 09/19/2016
ORIGINCLIMATE	Nick Facciola, Origin Climate Inc Oral Testimony: 09/22/2016
PACBEAUTIFUL	Yvette Lopez-Ledesma, Pacoima Beautiful Oral Testimony: 09/22/2016
PACIFICORP	Mary Wiencke, PacifiCorp Written Testimony: 09/19/2016
PANOCHE	Jon Costantino, Manatt, Phelps & Phillips, LLP Written Testimony: 09/13/2016
PANOCHE2	Robin Shropshire, Panoche Energy Center Board Hearing Written Testimony: 09/28/2016
PANOCHE3	Robin Shropshire, Panoche Energy Center Oral Testimony: 09/22/2016
PEREZ	Gema Perez, Private Individual Oral Testimony: 09/22/2016
PG&E	Nathan Bengtsson, Pacific Gas & Electric Written Testimony: 09/19/2016
PG&E2	Fariya Ali, Pacific Gas & Electric Oral Testimony: 09/22/2016
PG&E3	Nathan Bengtsson, Pacific Gas & Electric Oral Testimony: 09/22/2016
PGP	Therese Hampton, Public Generating Pool Written Testimony: 09/19/2016
PORTLANDGENELEC	Elysia Treanor, Portland General Electric Company Written Testimony: 09/19/2016
POWEREX	Nico van Aelstyn, Beveridge & Diamond PC on behalf of Powerex Written Testimony: 09/09/2016

Abbreviation	Commenter
PROCTER&GAMBLE	Simon Martin, Procter & Gamble Manufacturing Company Written Testimony: 09/13/2016
QUALCOMM	Gail Welch, Qualcomm, Inc Written Testimony: 09/19/2016
REDDING	Leslie Bryan, Redding Electric Utility Written Testimony: 09/19/2016
REDDING2	Leslie Bryan, Redding Electric Utility Oral Testimony: 09/22/2016
RINCON-VITOVA	Jan Dietrick, Rincon Vitova Board Hearing Written Testimony: 09/28/2016
RINCON-VITOVA2	Jan Dietrick, Rincon Vitova Oral Testimony: 09/22/2016
RUBYCANYON	Zach Eyler, Ruby Canyon Engineering, Inc Written Testimony: 09/19/2016
RUIZ	Rosalva Ruiz, Private Individual Oral Testimony: 09/22/2016
SANDLER	Mike Sandler, Carbon Share Written Testimony: 09/17/2016
SCCPA2	Sarah Taheri, Southern California Public Power Authority Oral Testimony: 09/22/2016
SCPPA	Tanya DeRivi, Southern California Public Power Authority Written Testimony: 09/19/2016
SDG&E	Adrianna Kripke, San Diego Gas and Electric Company Written Testimony: 09/19/2016
SDG&E2	Adrianna Kripke, San Diego Gas and Electric Company Oral Testimony: 09/22/2016
SEALASKA	Josie Hickel, SVP Energy & Resources Chugach Alaska Corporation Written Testimony: 09/19/2016
SEALASKA2	Nicholas van Aelstyn, Beveridge & Diamond PC on behalf of Sealaska Corp Board Hearing Written Testimony: 09/28/2016
SEALASKA3	Nico van Aelstyn, Alaska Native Regional Corporation for Southeast Alaska Oral Testimony: 09/22/2016
SHELL	John Leslie, Shell Energy Written Testimony: 09/19/2016
SILICONVALLEYPOWER	Kathleen Hughes, Silicon Valley Power, City of Santa Clara Oral Testimony: 09/22/2016
SIMPLOT	David Huck, JR Simplot Company Written Testimony: 09/19/2016

Abbreviation	Commenter
SMUD	Timothy Tutt and William Westerfield, Sacramento Municipal Utility District Written Testimony: 09/19/2016
SMUD2	Tim Tutt, Sacramento Municipal Utility District Oral Testimony: 09/22/2016
SOCAL Edison	Adam Smith, Southern California Edison Written Testimony: 09/19/2016
SOCAL Edison2	Adam Smith, Southern California Edison Oral Testimony: 09/22/2016
SOCAL GAS	Tim Carmichael, SoCalGas Board Hearing Written Testimony: 09/28/2016
SOCAL GAS2	Tim Carmichael, Southern California Gas Oral Testimony: 09/22/2016
SOLAR TURBINES	Craig Anderson, Solar Turbines Board Hearing Written Testimony: 09/28/2016
SONOMA CLEAN	Deb Emerson, Sonoma Clean Power Oral Testimony: 09/22/2016
STATE WATER	Tim Haines, State Water Contractors Written Testimony: 09/19/2016
STROMBERG	Janet Stromberg, Private Individual Oral Testimony: 09/22/2016
SURETY	Eli Gilbert, Surety & Fidelity Association of America Written Testimony: 8/30/2016
TRUJILLO	Felipa Trujillo, Private Individual Oral Testimony: 09/22/2016
TURLOCK ID	Ken Nold, Turlock Irrigation District Written Testimony: 09/19/2016
TURLOCK ID2	Brian Biering, Turlock Irrigation District Oral Testimony: 09/22/2016
TURLOCK ID3	Ken Nold, Turlock Irrigation District Oral Testimony: 09/22/2016
VALLEY ELECTRIC	Daniel J Tillman, Valley Electric Association, Inc Written Testimony: 09/19/2016
WARA	Michael Wara, Private Individual Written Testimony: 09/19/2016
WHITEHURST	Ron Whitehurst, Private Individual Oral Testimony: 09/22/2016
WONDERFUL	Melissa Poole, The Wonderful Company Written Testimony: 09/19/2016
WPTF	Clare Breidenich, Western Power Trading Forum Written Testimony: 09/19/2016
WSPA	Western States Petroleum Association Board Hearing Written Testimony: 09/28/2016

Abbreviation	Commenter
WSPA2	Tiffany Roberts, Western States Petroleum Association Oral Testimony: 09/22/2016
WURU	Todd Shuman, Wasteful Unreasonable Methane Uprising Oral Testimony: 09/22/2016

B. ALLOWANCE ALLOCATION

B-1. Electrical Distribution Utilities

Period Addressed by EDU Allocation

B-1.1. Multiple Comments:

LADWP supports ARB's continued efforts to prioritize the benefits gained from longer term certainty of allowance allocations. Such benefits would be further enhanced by specifying allocations through 2030. Doing so will enable utilities such as LADWP to make more informed long-term decisions when developing their Integrated Resource Plans. For example, longer-term certainty regarding the availability of allowances will provide utilities with stronger justifications that long-term investments in higher cost, lower carbon resources will not result in unexpectedly higher costs for ratepayers.⁵ Furthermore, utilities will better be able to justify near-term plans for further decarbonization in 2027-2030 if they know upfront that doing so will not reduce the number of allowances they will ultimately receive in those years. Finally, establishing allowance allocations through 2030 in a single rulemaking, rather than in a series of rulemakings, will reduce the administrative burden on ARB and the public. (LADWP)

Comment:

The Proposed Amendments to Section 95892(a) add two new allowance allocation periods for allocation of allowances to EDUs for the protection of their electricity ratepayers.

Those new sections would establish allowances for the period 2021 to 2026 (section 95892(a)(2)) and for 2027 and beyond (95892(a)(3)). The Staff Report and Proposed Amendments also note that a methodology for this allowance allocation may be proposed in the rulemaking process, and would be part of 15-day changes. As noted above, it is important that the post-2020 allowance allocation be established during this rulemaking for the entire 2021 to 2031 period. Affected stakeholders and compliance entities need this regulatory certainty. NCPA does not recommend bifurcating or delaying the allowance allocation determination for years 2027 and beyond. To the

⁵ Long-term certainty is particularly important for publicly-owned utilities, which require extra lead time in order to obtain approvals from politically accountable governance bodies such as city councils, and which operate under longer procurement time frames.

extent that the GHG budget in the Proposed Amendments is firmly established through to 2031, so too should be the allowance allocation to EDUs...

NCPA also believes that allowance allocations should be established during this Rulemaking for the entire period from 2021 to 2031. Regulatory certainty is critically important to compliance entities, and allocation of allowances should be clearly set in this rulemaking and should address the entire period covered by the current GHG Allowance budget. (NCPA)

Response: The commenters request that these regulatory amendments establish allowance allocation for electrical distribution utilities (EDU) during 2021-2030 or 2021-2031. Staff agrees that allocation to EDUs is appropriate through 2030, and proposed in the final regulatory amendments to establish allowance allocation for EDUs for the 2021-2030 period.

Thank you for the support.

B-1.2. Comment:

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 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. (PG&E)

Response: The commenter requests that the current rulemaking establish any plans for major changes to EDU allocation and that a 2025 rulemaking on these issues be avoided. The current rulemaking establishes EDU allowance allocation for 2021-2030.

Allocation for Costs Beyond those of the Cap-and-Trade Program

B-1.3. Multiple Comments:

Key Theme: Relieving customer 'cost burden' is the right approach to continuing utility allowance allocations past 2020, but the application of this principle should be broadened beyond this current regulatory proposal. JUG members believe a wider application of the 'cost burden' principle is necessary to assure customer costs for early actions, achievement of state policies designed to reduce GHG emissions (e.g., the RPS), and the role of the electricity sector in achieving emissions reductions in other sectors (e.g., vehicle electrification) are considered. The customer costs of achieving California's climate policy objectives for the electric sector in advance of required deadlines should be considered just as it is for utilities that exceeded RPS requirements. The cost burden principle should include:...

- Continued recognition of Qualifying Facilities and similar “priced at market” contracts
- Recognition of RPS contracts that have been accorded no GHG reduction value to the utility by ARB...
- [other bullet points included elsewhere in this document]

(JOINTUTILITIES)

Comment:

SMUD also supports the comments filed by the Joint Utility Group, covering the following key themes:

- Continuing consideration of the customer ‘cost burden’ principle is the right approach to determining utility allowance allocations, but the application of that principle should not be narrowed from the current application up through 2020...

(SMUD)

Comment:

SCE agrees with ARB staff that alleviating customer cost burden is the right guiding principle for post-2020 allocation. However, SCE also agrees with JUG comments that seek to expand the definition of what should count as ‘cost burden’. Please refer to JUG comments for a fuller treatment of the utilities’ list of reasonable costs that should be covered through ARB’s allowance allocation methodology. But in summary, the SCE and the JUG recommend that ARB’s cost burden principle should be expanded to include:...

- Continued recognition of Qualifying Facilities contracts
- [other bullet points included elsewhere in this document]

(SOCALEDISON)

Comment:

The Cost Burden to EDUs Associated with Meeting the State’s Climate Policies Must be Clearly Recognized in the Allowance Allocation Methodology to EDUs.

The Proposed Amendments only discuss allocation of allowances to the electrical distribution utilities at a high level, and note that details regarding allowance allocation proposals will be forthcoming in 15-day revisions. NCPA appreciates and fully understands the complexities of determining the appropriate allocation methodology to help ensure that the cost burden of meeting California’s aggressive GHG reduction objectives is not unduly borne by the residents and businesses of California’s electric distribution utilities. The electric sector and EDUs in particular, bear a disproportionate share of the cost burden of meeting California’s climate objectives. The allocation of

allowances to EDUs has been a key part of the successful implementation of the Cap-and-Trade Program and the extent to which the state's EDUs were able to meet their compliance obligations while providing direct benefits to their electricity customers and communities, while simultaneously reducing GHG emissions.

The Staff Report does not include proposed allocations for EDUs post-2020. Rather, the Staff Report notes that “staff proposes to continue allowance allocation to EDUs after 2020 using an approach based in part on the methodology used for 2013-2020 EDU allocations. Under such a proposal, the 2020 expected cost burden for each EDU would be the starting point for calculating post-2020 allowance allocations.” (Staff Report, p. 41)

NCPA supports the continuation of the allowance allocation policies used to determine the number of allowances allocated to the EDUs prior to the first compliance period. The value derived from the allowances allocated to the EDUs directly benefits the state's electricity ratepayers by protecting them from what would otherwise be significant rate impacts. In adopting the Cap-and-Trade Program regulation in 2011, CARB stated that:

“The electrical utility allocation is designed to protect electricity customers and reward these customers for utility investment in renewable energy and energy efficiency. Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than ratepayers.”⁶

The reasons and basis for freely allocating allowances to the electrical distribution utilities are just as true and relevant today as they were in 2011. Indeed, in the face of a tightening cap and increased compliance costs, free allocation of allowances to electrical distribution utilities, the value of which is used to directly benefit electric customers, is *even more important today* than it was in 2011. To date, many of the EDUs that received free allowances have used the value of those allowances to invest in GHG reducing measures and compliance cost mitigation that directly benefits their electric customers. These investments provide not only near term benefits in the form of reduced electric bills, but also provides the basis for long term reduction strategies that will be even more important as the cap tightens.

The allocation methodology ultimately adopted by CARB in 2011 was subject to months of stakeholder discussions and meetings, and multiple rounds of comments. It was non-updating and based on cost burden, energy efficiency, and early action—as defined by investment in renewables during the period 2007-2011. In the end, CARB concluded that the adopted approach

⁶ California's Cap-and-Trade Program, Final Statement of Reasons, October 2011 (2011 FSOR), p. 215.
4 2011 FSOR, p. 573-575.

“...fairly apportions value to the electric distribution utilities in a way that compensates retail customers for their cost, providing transition assistance, while maintaining a strong incentive for distribution utilities to make investments toward lowering their emissions profile. We believe that this approach is replicable for the beyond 2020 horizon and at the regional or national level.”⁴

The key principles upon which the preliminary EDU allowance allocation was based included covering the distribution utilities’ compliance cost burden, energy efficiency, and recognition of early investments.⁷ The “purpose of allowance allocation to the electric utilities is not for price mitigation, but to provide ratepayer relief while maintaining the price signal.”⁸ Allocation of allowances to EDUs for the benefit of their ratepayers has been demonstrated to be the best means by which to ensure that the value of the allowance continues to directly benefit electricity customers and the approach used in 2011 should be replicated moving forward.

Allocation of allowances to EDUs provides for the most direct means by which to help mitigate the cost impacts of GHG reduction policies on California residents and businesses. The electric sector, and in particular the EDUs, has already demonstrated significant emissions reductions, but those reductions came at increased electricity procurement and operational costs. The EDUs’ cost burden for transitioning to lower or non-GHG emitting resources and engaging in load reduction measures should be properly recognized in the context of the Program. Lower GHG portfolios and energy savings measures *directly* meet the objectives of the state climate policies. Procurement practices that move away from higher GHG resources should be recognized within the EDU cost burden because these actions taken to reduce GHG from the portfolio may ultimately result in compliance costs that exceed the cost of allowances. As such, defining the cost-burden properly is essential to determining the appropriate allocation of allowances to the EDUs. As noted by the California Joint-Utility Group, cost burden consideration should include:...

- Continued recognition of Qualifying Facilities contracts and similar “priced at market” contracts
- Recognition of RPS contracts that have been accorded no GHG reduction value to the utility by CARB...
- [other bullet points included elsewhere in this document]

(NCPA)

Comment:

Another basic tenet of the potential staff methodology is to base post-2020 allocations on a utility’s potential ‘cost burden’. SCPPA is supportive that this is the right guiding

⁷ 2011 FSOR, p. 575

⁸ 2011 FSOR, p. 2175

principle, but, as noted previously, this is a very data specific endeavor where the details really matter. SCPPA believes a wider application of that principle is needed to cover additional costs not currently included within ARB's definition of cost burden (e.g., the costs of utility GHG reduction measures adopted independent of the Cap and Trade Program). (SCPPA)

Comment:

The Cap-and-Trade Program, while a critically important tool in meeting California's GHG reduction and clean-energy goals, is not the only mandate on electric utilities associated with meeting those statewide policy objectives. Indeed, as but one of the many measures addressed in the Scoping Plan, the Cap-and-Trade Program is intended to complement other programs and measures addressed therein. Allocation of allowances to the EDUs is an important element of the Cap-and-Trade Program. As CARB has noted, the "purpose of allowance allocation to the electric utilities is not for price mitigation, but to provide ratepayer relief while maintaining the price signal."⁹ The need for ratepayer relief extends to cost associated with meeting the state's far-reaching climate objectives. The Staff Report and 45-day proposed amendments do not include a specific proposal for the post-2020 EDU allocation, but discusses a proposal for establishing the allocation "based in part on the methodology used for 2013-2020 EDU allocations." (Staff Report, pp. 41-43)

M-S-R appreciates the recognition that EDUs should continue to receive allowances and in collaboration with other stakeholders, is working with CARB staff on the appropriate methodology. Part of that evolving process includes determining the EDUs' cost burden. When assessing the cost burden on electrical distribution utilities of meeting clean energy goals, CARB must look at the totality of the measures EDUs are required to implement to reduce statewide emissions, and not consider the Cap-and-Trade program in a vacuum. Rather, the cost burden should be considered in the context of the Scoping Plan itself. This is critically important because EDU costs associated with these other programs have a direct impact on their compliance obligation under the Program. Reduced compliance costs associated with the Cap-and-Trade Program do not necessarily translate to a reduced cost burden for EDUs; California's electric utilities must meet renewable energy, energy efficiency, and energy storage mandates, for example, all of which should reduce GHG emissions but not necessarily at lower costs than Cap-and-Trade Program allowances. Furthermore, the electric sector alone will be responsible for ensuring California's compliance with the Environmental Protection Agency's (EPA) Clean Power Plan (CPP) should it become law, adding another level of compliance responsibilities on the sector.

For these reasons, M-S-R urges the Board to direct staff to continue to work with stakeholders on the important issue of determining the appropriate methodology for allocating allowances to the EDUs. M-S-R asks that the Board further direct staff to

⁹ California's Cap-and-Trade Program, Final Statement of Reasons, October 2011 (2011 FSOR), p. 2175.

address cost burden consistent with the principles for defining cost burden set forth in the comments of the Joint Utility Group in furtherance of developing that methodology. (M-S-R)

Comment:

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)

Comment:

And we support the comments made by the earlier utilities on the definition of that cost burden, which includes compliance with myriad other greenhouse gas emissions reductions programs that directly fall on the utilities and the electric customers of those utilities. (NCPA2)

Comment:

We agree with the Joint Utility Group's proposal that the cost burden principle is the right one to be focused on. However, we do agree that we think it should be broadened, point 2. (SOCALEDISON2)

Response: The commenters request that the costs included in the “cost burden” concept be expanded to include various other costs faced by EDUs. 2021-2030 allowance allocation to EDUs is based on the costs that utilities are likely to face due to Cap-and-Trade Program costs associated with their loads. This is the “cost burden” to which staff refers in EDU allowance allocation discussions. “Cost burden” is also defined in Attachment C to the First Notice of Public Availability of 15-Day Amendment Text in this rulemaking.

The purpose of EDU allocation is to protect EDU ratepayers from the costs that the Cap-and-Trade Regulation imposes on these ratepayers as a whole. Staff is aware that EDUs are subject to a variety of other regulatory requirements and that those requirements may result in costs to EDUs and their ratepayers. Allowance allocations are not designed to prevent EDUs and their ratepayers from facing costs due to all other State programs. When allocating allowances, staff weighs the benefits of the proposed allocation against the benefits of making those allowances available to other market participants. One consideration in this assessment is equity with other covered entities. Staff notes that non-utility covered entities do not receive allocations for the costs of compliance with other programs and finds that an EDU facing costs due to other

regulations is not a sufficient reason to remove allowances from the pool of allowances to be auctioned by the State and allocate them to EDUs.

Several commenters emphasize costs due to the Renewables Portfolio Standard (RPS) in particular, which is a State program that seeks to increase the amount of renewable electricity sold in California. EDUs express concern about the costs of complying with that requirement and the Cap-and-Trade Program given that they share the goal of reducing GHG emissions. ARB has addressed this issue by focusing on the RPS requirement as the driver of GHG reductions when calculating EDU allowance allocations. EDUs are unique among sectors in that RPS requires them to reduce significantly the GHG emissions intensity of their product over time. As the required percentage of RPS-eligible electricity increases over time, that increase is reflected in EDU allowance allocation calculations for 2021-2030. Other regulatory requirements such as coal divestiture have also reduced electricity sector GHG emissions.

The RPS-eligible zero-emissions electricity assumed in allocation calculations was also reduced in the second 15-day amendment package by five percent below RPS requirements to represent GHG-emitting electricity that is RPS-eligible because it “firms and shapes” zero-emission electricity or otherwise reflects differences between the RPS and Cap-and-Trade Programs. Given that EDU allocations are used to benefit retail ratepayers, these changes were deemed appropriate in order to continue to protect ratepayers as the cap becomes more stringent over time.

Several of the commenters specifically requested allocation for the costs of purchasing electricity from “qualifying facilities.” Federal law requires investor-owned electric utilities to purchase electricity from facilities deemed to be qualifying facilities at rates overseen by the California Public Utilities Commission. 2013-2020 EDU allowance allocation included allocations for *renewable* electricity which California EDUs buy from qualifying facilities. However, as staff has previously noted in Appendix C to the First 15-Day Notice, the emissions attributable to renewable electricity from qualifying facilities is predicted to be 251 GWh in 2020 and 101 GWh in 2024, representing a very small percentage of California electricity.¹⁰ Also, 2013-2020 allocations included a top-down component based on electricity sector-wide information and a bottom-up component based on utility-specific information, with the difference in emissions allocated among EDUs to reward utilities for early GHG-reducing activities and energy efficiency. In contrast, 2021-2030 EDU allocations are based on bottom-up calculations, leaving no “extra” allowances to allocate for early action. For these reasons, staff does not consider it necessary to allocate for renewable QF electricity in calculating EDU allowance allocation. Non-

¹⁰ See Appendix C to the 1st 15-day Notice, footnote 7, citing CEC 2015. Renewable QF power, not all QF power, was allocated for in 2013-2020 EDU allocations.

renewable QF electricity is included in allocation calculations like all other non-renewable electricity.

The discussion above addresses EDU costs due to compliance with other State regulations or programs. Further specific costs that some commenters requested be included in “cost burden” are discussed below.

B-1.4. Comment:

PG&E also recommend that the allocation methodology continue to account for all other nonemitting 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. (PG&E)

Response: Staff does not believe it is appropriate to allocate for zero-GHG emitting electricity, such as electricity from the renewable qualifying facilities, because that electricity has no GHG cost associated with it. In response to discussions with EDUs regarding how not all zero-emissions electricity has no compliance obligation under the Cap-and-Trade Regulation, staff proposed that EDU allocation increase by changing assumptions about the amount of RPS-eligible electricity that has zero GHG emissions. Further details on this change are outlined above in response to comments B-1.3.

B-1.5. Multiple Comments:

The cost burden principle should include:...

- Recognition of carbon reduction actions taken by utilities between 2009 and 2015 above and beyond what was required under various state programs
- Early GHG reductions due to distributed renewable generation...
- Allocation which recognizes other voluntary commitments (Examples include the Diablo Canyon plan for GHG-free replacement power, and JUG members exiting Intermountain Power Plant contract early)

(JOINTUTILITIES)

Comment:

Cost burden should consider voluntary investments in renewables, energy efficiency investments, and investments in residential behind-the-meter distributed generation...

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. 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...

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"¹¹ 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)

Comment:

Related to allowance allocation methodology, CMUA does agree that relieving cost burden is the correct approach for post-2020 allowance allocations. CMUA does, however, believe that the cost burden principle should be applied more widely to assure customer costs for early actions and better achieve California's climate policy objectives.

For example, cost burden considerations should include recognition of early GHG reductions from increased investment in energy efficiency programs in GHG reductions due to distributed renewable generation. (CALMUNIUTILASSOC)

Comment:

But we would like to see that cost burden umbrella expanded to more completely recognize the carbon reduction costs that are borne by utility customers. These include energy efficiency investments, renewable distributed generation investments, like

¹¹ Air Resources Board. Cap-and-Trade Regulation 2016 Amendments: Setting Post-2020 Emissions Caps. March 29, 2016.

rooftop solar, increased electrification, and most significantly voluntary investments in renewables beyond RPS mandates.

This last point is important, and it's especially important for utilities that are moving away from coal or nuclear generation and replacing those generation assets with renewables beyond the RPS mandate. This should be encouraged through allocation to make those environmental commitments.

So PG&E submitted detailed comments on how these investments in GHG reductions should be recognized through allocation. And we ask the Board direct staff to work with the joint utilities to find a way to make that happen. (PG&E3)

Comment:

Recognition of Energy Efficiency and Distributed Generation Investments: SMUD understands that one reason ARB staff is considering a “true-up” of the cost-burden allocation approach in 2021 is that statewide retail sales are now forecast in 2020 to be significantly less than the retail sales forecasts underlying the 2013-2020 allocations. Two of the main reasons for these lower forecasts are the significant investments in energy efficiency programs and distributed generation resources made by the EDUs and their customers.

SMUD suggests that cutting the allocation of 2021 allowances significantly below 2020 allowances represents a disincentive for continued energy efficiency and distributed generation investments. One of the reasons utilities invest in measures that will lower sales is to lower their carbon obligations, and cutting allowance allocations dramatically to reflect lower sales challenges the incentive to invest. Prior to 2020, EDU investment in these measures reduces their obligation in relation to their allocated allowances, but that benefit is not preserved by cutting allowances in 2021.

SMUD suggests that if allowance allocation to EDUs is “adjusted” in 2021 to reflect lower expected retail sales, a component should be added back to preserve the incentive for investment in energy efficiency and distributed generation. (SMUD)

Comment:

Related to allowance allocation methodology, CMUA does agree that relieving cost burden is the correct approach for post-2020 allowance allocations. CMUA does, however, believe that the cost burden principle should be applied more widely to assure customer costs for early actions and better achieve California's climate policy objectives.

For example, cost burden considerations should include recognition of early GHG reductions from increased investment in energy efficiency programs in GHG reductions due to distributed renewable generation. (CALMUNIUTILASSOC)

Comment:

As noted by the California Joint-Utility Group, cost burden consideration should include:...

- Recognition of carbon reduction activities undertaken by utilities between 2009 and 2015 above and beyond what was required under various state programs
- Early GHG reductions due to distributed renewable generation...
- Allocation which recognizes other voluntary commitments (Examples include the Diablo Canyon plan for GHG-free replacement power, and JUG members exiting Intermountain Power Plant contract early)

(NCPA)

Response: The commenters request allocation to EDUs for EDUs' voluntary GHG-reducing activities. These activities include utilities' own voluntary GHG-reducing activities and their customers' voluntary installation of distributed generation.

Staff supports utilities' taking voluntary action to reduce GHG emissions from electricity generation. Given that EDU allowance allocation is based on cost burden, this is one of the reasons that ARB has opted to set fixed EDU allowance allocations for 2021-2030. Any changes that utilities make to reduce GHG emissions will reduce their GHG costs while not changing their allocations, thus resulting in a net benefit. This incentive is inherent to the Cap-and-Trade Program and applies in all sectors that see costs from the Program.

Staff did include allocation for voluntary GHG reductions in EDU allowance allocation calculations for 2013-2020. 2013-2020 EDU allocations included a top-down component based on electricity sector-wide information with a percentage of the sector allocation amount designated for each EDU based on bottom-up, utility-specific information, and the difference between the top-down and bottom-up cost burdens was distributed as allocated allowances to recognize energy efficiency and early action to reduce GHG emissions. "Early action" refers to GHG-reducing actions which were taken before the Cap-and-Trade Program was implemented. This approach recognized utilities' early commitments to GHG reductions and was consistent with the overall 2013-2020 EDU allocation approach.

For 2021 and later allocations, staff does not find it necessary to allocate specifically for voluntary GHG reductions undertaken by utilities during 2015 and earlier. Utilities will benefit from these reductions in the years up through 2020. It is infeasible for the Cap-and-Trade Program to allocate benefits for early actions indefinitely. As discussed in response to 45-day comment B-1.4, EDUs will benefit from these activities, given that allocations are fixed. Staff finds it

reasonable to allow EDUs to benefit from these actions until the new allocation calculations are used starting in 2021.

The commenters identify “other voluntary commitments” as a category which includes PG&E’s plans for replacing nuclear Diablo Canyon Power Plant power, planned changes to the coal-using Intermountain Power Plant which serves several California EDUs, and other unspecified commitments. Staff views these items in different ways. In general, staff has used the cost burden principle for 2021-2030 EDU allocation to protect ratepayers rather than allocating based on avoided GHG reductions. ARB does not allocate for zero-emissions power, including distributed generation, for reasons discussed above. Further, distributed generation often refers to power which customers choose to install, which is therefore not subject to incentives applied to utilities.

To reward early conversion away from coal and provide the incentive effect several commenters mentioned, ARB has allocated for the Intermountain Power Plant power as if it were to continue providing coal power through June 2027, when its contract ends. Similarly, power from the Diablo Canyon Power Plant is included until its operating licenses expire. Treatment of the Intermountain Power Plant is discussed further in the response to 45-day comment B-1.7 and treatment of the Diablo Canyon Power Plant is discussed further in the response to first 15-day comment B-1.10.

The CMUA comment mentions both distributed renewable generation and energy efficiency. Energy efficiency programs are discussed below in response to 45-day comment B-1.6.

B-1.6. Multiple Comments:

The cost burden principle should include:

- Recognition of early GHG reductions from increased investment in energy efficiency programs...

(JOINTUTILITIES)

Comment:

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. (PG&E)

Comment:

But in summary, the SCE and the JUG recommend that ARB's cost burden principle should be expanded to include:

- Recognition of continued investment in EE programs, as in the previous allocation

(SOCALEDISON)

Comment:

As noted by the California Joint-Utility Group, cost burden consideration should include:

- Recognition of early GHG reductions from increased investment in energy efficiency programs... (NCPA)

Comment:

Distributed Generation and Energy Efficiency: ARB Staff have recommended that allocations "recognize investments in zero-emitting energy sources" for industrial compliance entities. SCPPA recommends similar treatment for smaller energy users. Continued investment in energy efficiency is among the most beneficial and cost-effective means of combating climate change and should be encouraged through every available means, as increased energy efficiency is the primary means of decoupling economic growth from GHG emissions growth. In 2010, ARB included investments in energy efficiency programs in its cost basis methodology; SCPPA supports a continuation of that precedent. (SCPPA)

Response: The commenters request that EDU allowance allocation take energy efficiency investments into account. The calculation of 2021-2030 EDU allowance allocation considers energy efficiency as part of load (as reported in S-2 forms, Form 1.5a or PacifiCorp's revised IRP projections), thereby allocating allowances for it. Staff deems this an appropriate means of encouraging measurable energy efficiency. See also response to 45-day comment B-1.5 and Attachment C to the First Notice of Public Availability of 15-Day Amendment Text in this rulemaking.¹²

¹² <https://www.arb.ca.gov/regact/2016/capandtrade16/attachc.pdf>.

Utility-Specific Details of Allocation Calculations

B-1.7. Multiple Comments:

Planned retirements: Between now and 2030 there will be retirements of large coal-fired generating facilities. Any early retirement prior to contract expiration is a benefit to the environment at a cost to participating utility ratepayers. ARB should not penalize (by way of a lower allowance allocation) any utility that voluntarily exits these types of contracts early. Allocations should be based on contractual dates, not on potential early exits. Specifically, some SPPA Members are under contract to procure power from the Intermountain Power Project through June 15, 2027; however, there have been aspirational discussions of repowering to use natural gas in 2025. As noted above, SPPA strongly suggests that ARB base allowance allocations on the current contractual obligations in place and not on aspirational planning targets. (SPPA)

Comment:

ARB Should Accurately Reflect the Planned Retirement Date of Intermountain Power Plant in Cost-Based Allocation Methodology

As part of the cost-based allocation methodology, ARB has assumed that the two existing coal units at the Intermountain Power Plant (IPP) will retire in 2025 and repower as a natural gas combined cycle facility.¹³ However, existing power purchase contracts do not expire until 2027.¹⁴ Such contracts include the Power Sales Contract between Intermountain Power Agency (IPA), the entity that holds legal title to IPP, and LADWP and the Excess Power Sales Agreement, which requires LADWP to purchase 88.281% of the available excess power through the end of June 15, 2027 expiration date.

LADWP has set an ambitious goal to replace these two existing coal units several years early. This goal, however, is not a binding obligation to do so. LADWP's ability to meet this earlier date is contingent upon several factors, including the completion of a lengthy permitting process to build the new gas-fired replacement units, material procurement of the components and construction of those replacement units, and final concurrence of all 35 participants of the power sales contracts to terminate those contracts early.

Given the considerable uncertainty regarding the actual retirement date of the IPP units, ARB should incorporate a 2027 retirement date, rather than the aspirational target date of 2025, into its cost-based allocation.

¹³ See 2016 ISOR, Appendix F at 2574, ("Adjust allocation after IPP retirement in 2025 for those EDUs with IPP contracts").

¹⁴ See Intermountain Power Agency, About Intermountain Power Agency <http://www.ipautah.com/about/index.asp> ("All Purchasers have executed Power Sales Contracts with IPA that provide the basic security for the debt service on all bonds issued by IPA for construction and acquisition of the Project, exclusive of the STS. Additionally, the Purchasers have agreed to pay all Project costs of Operation and Maintenance for Project facilities. The Power Sales Contracts expire on June 15, 2027.").

Additional reasons why the allocation of allowances through 2027 would be a more equitable approach include the following:

- The process of replacing the two years of IPP generation carries substantial costs. The cost of IPP repowering to natural gas is substantial, and expediting the completion of the repowering early would most likely add to those incremental costs. In the alternative, LADWP would have to replace the coal-fired generation from IPP by purchasing more expensive replacement power (from low- and zero-emitting power resources) on the market. Therefore, even if LADWP is able to exit its contract with IPP two years early, doing so will entail substantial costs, which will have direct and substantial cost impacts on California ratepayers. The purpose of the cost-based allocation is to mitigate this type of cost burden through the allocation of allowances.¹⁵
- Providing an allocation assuming IPP will be in operation through 2027 also provides EDUs with the proper incentives to exit from high-emitting contracts early. In fact, in 2011, the ARB adopted a resolution directing the Executive Officer to consider amending the Cap-and-Trade Regulation to "provide appropriate incentives for accelerated divestiture of high emitting resources by recognizing that these divestitures can further the goals of AB 32."¹⁶

(LADWP)

Response: The commenters request that EDU allowance allocation assume that the Intermountain Power Plant will be in operation through 2027 because its contract ends in 2027 and this assumption will reward utilities if the plant closes early. Staff agrees, and in the second 15-day proposal to change the Regulation, staff proposed 2021-2030 EDU allowance allocations that assume that coal power from the Intermountain Power Plant will be purchased through June 2027, when utilities' contracts with the plant end. This change incentivizes the early plant closure that the commenters have requested.

B-1.8. Comment:

PacifiCorp supports ARB's "cost burden" approach to post-2020 utility allowance allocations. PacifiCorp also generally supports comments submitted by the Joint Utility Group regarding the application of this principle.

¹⁵ ARB, Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector at (July 27, 2011), <https://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf> [hereafter "Appendix A"] ("Cost burden is expected to result from emissions costs associated with fossil, QF, and non-emitting resources priced at market being passed from generators and marketers to utility customers") (emphasis added).

¹⁶ ARB, Resolution 11-32 at 11 (Oct. 20, 2011), <https://www.arb.ca.gov/regact/2010/capandtrade10/res132.pdf>

ARB proposes to use load data from the California Energy Commission 2015 Energy Demand Forecast and resource data from 2015 S-2 forms, supplemented by additional data as needed.

Due to its small service territory in California and its status as a multi-state utility, PacifiCorp is not currently required to submit the S-2 form. In addition, as a multi-jurisdictional retail provider (MJRP), PacifiCorp's compliance obligation under the Cap-and-Trade Program is developed uniquely through the establishment of a system emission factor. PacifiCorp develops its load forecasts and resource plans through its integrated resource plan ("IRP"), which is filed with the California Public Utilities Commission as well as PacifiCorp's five other state utility commissions. Through informal conversations with ARB staff, PacifiCorp understands that flexibility is available to utilize a methodology for calculating PacifiCorp's allocation that takes the IRP and system emission factor approach into account. PacifiCorp looks forward to working with ARB to develop this methodology. (PACIFICORP)

Response: PacifiCorp expresses interest in working with ARB staff to determine the appropriate load and resource projections to use for their utility when calculating 2021-2030 allowance allocations, given that it does not submit the same forms that are submitted by most California-based utilities. ARB agrees that PacifiCorp is in an unusual position compared to other utilities because it does not submit an S-2 form and it delivers most of its electricity outside of California. Staff worked with PacifiCorp and used PacifiCorp's projected resource mix, based on an update to its Integrated Resource Plan, as the basis for PacifiCorp's 2021-2030 allowance allocation. This information was included as part of the first and second 15-day proposed changes to the Regulation.¹⁷ The assumptions used in PacifiCorp's allocation, including those about meeting RPS requirements, are the same as those used for other utilities.

B-1.9. Multiple Comments:

In Calculating Allowance Allocations to EDUs, The ARB Should Account for the Individual Utility Load Growth Assumptions.

Allowance allocation is perhaps the most important issue in the development of a post 2020 Cap-and-Trade program. The current methodology addresses the diversity in California's electricity sector. Since utilities are complex and affected differently by Cap-and-Trade, it is important to recognize that diversity in the allocation methodologies. The use of the S-2 forms takes an important step in fulfilling this objective. However, an assumption of flat load growth across the entire electricity sector does not address the variability among utilities. Utilities like TID that have territories with more affordable

¹⁷www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015%20IRP%20Update/2015_IRP_Update_Load_Forecast.pdf,
www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015%20IRP%20Update/2015_IRP_Update_Projected_Energy_Mix.pdf.

costs of living can reasonably expect to see load growth. Furthermore, by virtue of POU's smaller size, even a single new large customer can swing load growth more than 1%. The ARB should recognize some load growth variation in their allocation methodology. (TURLOCKID)

Comment:

I'd also like to note that a lot of the regulation we're looking at -- staff is looking at paints all of the utilities with the same brush. Our area has low growth.

And I know that hasn't been spoken of yet today, but we're going to -- our load is going to keep growing.

And in part of the allocation process, the staff is proposing that everyone has a flat load growth. Well, that has an effect on us, along with RPS adjustment, along with switching of the EITE.

And I'd just like to be in that allocation process. It is a bottoms-up process this time around, and I'd like to be -- have you guys aware that, of course, you should look at all of us individually, not as one big same group. (TURLOCKID3)

Response: Turlock Irrigation District requests that ARB consider load growth variation among utilities. Staff agrees that it is appropriate to consider load growth in calculating 2021-2030 EDU allowance allocations, and in the first 15-day regulatory change proposal used regional and utility specific load growth factors. These growth factors are from the California Energy Commission's Form 1.5a, or from Form 1.1c for EDUs not listed or mapped to regions listed in Form 1.5a. This approach is applied consistently across all utilities and relies on the Energy Commission's load growth forecasts.

Allocation for Transportation Electrification

B-1.10. Multiple Comments:

Incorporating costs incurred from increased load due to electrification is critical...

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 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.(PG&E)

Comment:

The cost burden principle should include:...

- Recognition of GHG reductions associated with electrification that result in load growth due to fuel switching...

Finally, on the potential increase of electric sector emissions due to increased electrification, JUG members support developing a methodology to allocate allowances to the electric sector for electrification activities that reduce greenhouse gases from other sectors. This effort is consistent with the legislative intent of SB 350, which was to help offset the ratepayer impacts of vehicle electrification through cap-and-trade allowance allocations. JUG members agree that more time would be beneficial to consult widely with stakeholders and get these methodologies right. (JOINTUTILITIES)

Comment:

ARB should continue to remove disincentives for increased electrification in Transportation and other end-uses. SCE would like to highlight the need for ARB staff to continue its work with stakeholders to understand a methodology for allocating allowances due to increased electrification in order to implement Section 3 of SB 350.¹⁸ As the state continues towards its long-term climate targets, the emissions intensity of delivered electricity will continue to fall, making it an ever more attractive option as an end-use fuel. Electricity's role in powering transportation systems, industrial boilers, and building heating are just a few examples of the applications that may increase the emissions attributable to SCE (due to the nature of ARB's current accounting system) but would result in clear emission reductions from a societal perspective. SCE looks forward to discussing options to quantify these cross-sectoral effects and determine a reasonable method for delivering allowances to utilities where they are warranted. (SOCALEDISON)

Comment:

But in summary, the SCE and the JUG recommend that ARB's cost burden principle should be expanded to include:...

- Recognition of load growth due to fuel switching and increased electrification

(SOCALEDISON)

Comment:

Point 3, we think it should be broadened specifically, and it's been kind of discussed lightly in the work that staff has done so far, but we don't really have a firm methodology

¹⁸ Which added Health and Safety Code Section 44258.5

for how to do it, and that's to account for increased emissions due to transportation electrification, and other forms of electrification.

As you saw in the -- kind of -- I think it was the first presentation to kick us off today, South Coast has a significant amount of work ahead of it.

Electrification will play a key part in attaining, not just attainment, but also some of our GHG goals. And I think that, you know, ensuring that utilities and utility customers specifically are insulated from any kind of increased cost of compliance with the Cap-and-Trade Program is crucial to ensure that there's no disincentive to allow that transition to electrification as an end-use -- you know, electricity as an end-use fuel to occur. (SOCALEDISON2)

Comment:

We urge that transportation electrification be considered at this time during this rule-making, as part of an allowance allocation to the EDUs. We support the continuation of cost containment measures as long as those linkages as part of the cost containment measure are meaningful and optimize the benefits to California entities, and don't compromise the availability of compliance instruments for California compliance entities. (NCPA2)

Comment:

Lastly, widespread electrification, including the growth of electric vehicles, will play an important role in meeting the State's greenhouse gas targets. The ARB should enable allowances for increased electrification, which is consistent with SB 350's call for widespread vehicle electrification and acknowledgement of the corresponding impact on POUs from such electrification. (CALMUNIUTILASSOC)

Comment:

In Calculating Allowance Allocations to EDUs, The ARB Should Allocate Allowances for Electric Vehicle Charging.

The ARB should acknowledge the disproportionate burden borne by the energy sector as it leads the way to a cleaner more renewable future. There is no question that vehicle electrification and electrification of certain residential, commercial and industrial processes will play a critical role in the achievement of the State's ambitious climate targets. The 2015 IEPR recognizes the increasing role the electricity sector will play in achieving state-wide GHG emissions reductions:

The electricity sector accounts for about 20 percent of statewide GHG emissions, with about half from electricity imported from out-of-state, whereas the transportation sector is the largest source of GHG emissions, accounting for about 37 percent.³

Consequently, decarbonizing the transportation sector should be a primary focus of the state's climate goals, and policies in the electricity sector must build on policies to reduce emissions from the transportation sector. For example, new renewable

procurement should go hand-in-hand with increased electric loads from electrification of the transportation sector. If they are not in lock-step, then California will not realize the full potential of the GHG reductions from decarbonizing the electricity sector.

“Another way to reach ZNE is to replace natural gas appliances, such as gas stoves, water heaters, and space conditioning units, with electric appliances; such fuel-switching is called “electrification.”¹⁹

Similarly, SB 350 recognizes this trend and directs the ARB to “identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered should include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification.”²⁰

The ARB should work with the CEC to build on the load growth estimates developed in the 2015 IEPR. The agencies should develop load growth estimates to 2030 that account for the trends in electrification of vehicles and other processes. Since the installation of new meters at every customer site with EV charging is infeasible (i.e., the only way to verify actual EV load growth), we believe that working with the CEC to develop load growth estimates is the only way to meet the statutory intent of Cal. Health and Safety Code Sec. 44258.5. (TURLOCKID)

Comment:

I'd also like to mention that we think it's really important as the utility sector is going to replace much of the transportation sector, that we're also given allowances for, or at least an allocation process. (TURLOCKID3)

Comment:

As noted by the California Joint-Utility Group, cost burden consideration should include:...

- Recognition of GHG reductions associated with electrification that result in load growth due to fuel switching...

The Impacts of Transportation Electrification on EDUs Must be Recognized within the Program

¹⁹ See 2015 IEPR at pp. 43 and 50, available at: <https://efiling.energy.ca.gov/getdocument.aspx?tn=210527>

²⁰ Cal. Health and Safety Code Sec. 44258.5

California has a clearly defined goal of increasing electrification of all aspects of the transportation sector. Added to this, the state is increasingly moving towards electrification of other sectors of the economy. Both of these objectives will have the benefit of reducing the state's overall GHG emissions and improving air quality. However, a consequence of meeting these objectives is an increase in the use of electricity throughout the state. While ideally increases in electric load would be met with zero and low-emitting generation resources, doing so will not always be feasible. As a result, the state's EDUs, such as NCPA's member utilities, could see increases in their emissions. However, the Proposed Amendments do not include changes to address the impacts of transportation electrification on the EDUs. This is despite the fact that the potential impact was recognized by the legislature in Senate Bill (SB) 350. In the Legislature's clear direction to encourage greater transportation electrification, there was also acknowledgment of the corresponding impact on electric retail sellers and publicly owned utilities (POUs) from such electrification.²¹ Since the first allowance allocation was made, the State has continued to enact greater emissions reductions measures, many of which are aimed at reducing petroleum usage in transportation fuels. Recognizing the potential impacts on the electricity sector of transportation electrification,²² the Legislature directed CARB to identify and adopt policies, rules, or regulations that would remove barriers to electrification, including "an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification."²³ The significance of this direction, as well as the overall implications of transportation electrification must also be factored into CARB's final allowance allocation analysis at this time, and not be deferred to a future rulemaking. Allocation of allowances to EDUs will be a critical tool in helping to ensure that efforts and measures that increase electrification will continue without adversely impacting electric utility ratepayers.

During the March 29, 2016 Workshop, staff proposed that allowances can be allocated to EDUs to recognize the impacts of electrification through "evidence-based allocation." (3/29/16 Workshop p. 24) Staff expressed a desire to ensure that there is a verifiable basis upon which to base an allocation of allowances to the EDUs for increased

²¹ Health & Safety Code § 44258.5(b) The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification.

²² Senate Bill 350 adds Section 237.5 to the Public Utilities Code, which provides that: "Transportation electrification' means the use of electricity from external sources of electrical power, including the electrical grid, for all or part of vehicles, vessels, trains, boats, or other equipment that are mobile sources of air pollution and greenhouse gases and the related programs and charging and propulsion infrastructure investments to enable and encourage this use of electricity."

²³ Senate Bill 350; Health and Safety Code Section 44258.5(b).

emissions associated with transportation electrification. Since that time, it appears that the complexities of designing a metric that can be used to “quantify and verify increased load due to electrification”²⁴ have caused Staff to recommend that the issue not be addressed at all during this Rulemaking. NCPA does not agree with this conclusion and believes that CARB must be front facing and take on the issue of impacts associated with transportation electrification on the electric sector during this rulemaking and in the context of determining the appropriate allocation of allowances to the EDUs.

NCPA appreciates the importance of establishing the appropriate metric for measuring the impacts of this transition. However, that metric need not – and should not – be so cumbersome as to restrict practical acknowledgement of the impacts of transportation electrification. Accurate accounting must be ensured to the greatest extent feasible, yet should not include reporting or tracking requirements that are so burdensome that they result in significant additional costs for EDUs. NCPA notes that such an outcome would be particularly egregious for smaller POUs, many of which are located in the very areas where added incentives are necessary to encourage and spur electric vehicle deployment and the necessary electrical infrastructure.

Since transportation electrification is intended to play an increasingly significant role in moving the state towards its 2030 and 2050 emission reduction targets, it is important that the impacts of these changes be addressed sooner, rather than later. NCPA urges the Board to direct staff to continue dialogue with the affected stakeholders, as well as the CEC and CPUC, on potential methodologies that will accurately capture the emission ramifications of transportation electrification. These further deliberations and assessment of options should be conducted as part of this current rulemaking and proposed amendments to address the effects of transportation electrification on the EDUs should be included in 15-day changes to the regulation. (NCPA)

Comment:

Transportation Electrification

Without a doubt, electrification of other sectors will have a beneficial impact on total statewide GHG emissions and play an important part in meeting the state's climate objectives. At the same time, increased electrification of California's homes, businesses, and modes of transportation will result in increased GHG emissions in the electric sector. The legislature clearly acknowledged this link in Senate Bill 350 when it added section 44258.5 to the Health & Safety Code. H&S section 44258.5(b) provides:

“The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas

²⁴ Staff Presentation, March 29, 2016 Workshop, p. 24.

emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification.”

Despite this charge, the proposed amendments do not address this issue at all. The Staff Report notes only that “Staff is continuing to evaluate how increased electrification for the transportation sector for the post-2020 period should be accounted for in the allocation methodology for EDUs.” (Staff Report, p. 43) M-S-R agrees that it is important to ensure that there is an accurate method to calculate the impacts, but does not believe that it is appropriate to exclude transportation electrification impacts from the allowance allocation discussion at this time. The 15-day language should include Proposed Amendments that address the manner in which increased emissions for EDUs from transportation electrification will be specifically recognized in the Cap-and-Trade Program. (M-S-R)

Comment:

Additional Allowances for Electrification: SMUD appreciates the ARB staff consideration of adding allowances to EDU allocations to cover additional load and emissions from electrification. Broad substitution of electricity for combustion of fossil fuels is an essential measure for achievement of Governor Brown’s goal of a 50% reduction in petroleum use in vehicles by 2030. It is well established that electrification will reduce GHG emissions because it would result in a greater decrease in emissions from the sectors or end-uses being electrified than the increase in emission from additional electrical load. Nevertheless, utilities might hesitate to spend heavily on electrification if their increase in emissions is not covered by allowances in the Cap-and-Trade program.

However, a proposal that requires metering of the additional load from electrification of transportation, or some equivalent demonstration of this load, could prove to be a barrier. Most electric vehicles are currently charged at home, using a dedicated circuit or a simple normal outlet, neither of which is typically metered separately from the house as a whole. Requiring a separate meter for demonstration of the additional load would be an unnecessary expense. ARB should be comfortable relying on the demonstration and verification of increased electric load through conservative estimation that is used to provide Low Carbon Fuel Standard (LCFS) credits in that program. It would be efficient for the Cap-and-Trade Program to take advantage of the same methodology as this complementary program, and wasteful if the Cap-and-Trade Program rejected a methodology that is fully accepted by a sister program at ARB. The dramatic reductions of GHG emissions on the transportation side of the ledger (approximately 4 times the increases in emissions in the electric sector) is more than sufficient to support the concept that the barrier on the electric side can be removed by providing allowances based on a simple, cost-effective structure that does not require metering or the equivalent.

Electrification of other end-uses, such as water heating, space heating, etc. is considered necessary by many academic studies to achieve the State's long-term GHG goals. Once again, while likely less significant in magnitude than transportation electrification, it is not cost-effective to separately meter this load increase for purposes of demonstration of the load to receive allowances. EDUs could provide an estimation here similar to that for electric vehicles, based on a demonstration of the penetration of electric technologies for each end use, and the standard end use intensities (EUI) that are used in forecasting models and energy efficiency programs for various technologies (such as a heat-pump water heater that has a specific rated efficiency). While individual installations can use different amount of electricity depending on consumer behavior, etc., these standard values are sufficient to provide good estimates of the electricity load involved. Verification would then simply be verification of installation or penetration of the technologies – how many were installed – rather than a complicated statistical analysis of before and after electricity use or some system of individual meters for each appliance.

In both cases, for transportation and for other end-use electrification, SMUD again suggests that an alternative is to use a basic sales-based allocation overall for the electric sector, or a transition to such an allocation structure by 2030. This allocation structure automatically includes the increased load due to electrification, so relieves the EDUs and ARB from coming up with a method of demonstrating and verifying the electrification load separately from retail sales on an annual basis. It also automatically incentivizes lower-emitting grid generation, since allocations based on sales do not decrease as an entity shifts to lower emitting resources to serve those sales.

However, SMUD recognizes that a pure sales-based allocation structure is a significant departure from the current “cost-burden” structure for EDUs, and may not be seen as viable for EDUs that do not have significant legacy zero-emission resources (hydro and nuclear). Hence, SMUD suggests that the ARB consider development of a “cost-burden adjusted” sales-based allocation structure. In this concept, the sales supported by average-year generation from legacy zero-emitting resources and the 33% renewable portfolio standard would be identified for each EDU. This constant amount would be subtracted from the annual retail sales of each EDU, just like in the current cost-burden approach, and the remaining sales (with a cost-burden), would be multiplied by an emissions factor that reflects the cost-burden of these remaining sales (e.g. a natural gas default emission factor). This concept includes an annual “true-up” into the current cost-burden allocation structure, and so automatically covers the increased cost-burden from electrification. In step form, the allocation structure could include the following:

- Identifying the average annual sales supported by hydro and nuclear resources for each EDU and 33% renewables.
- Subtracting that number from each EDUs verified retail sales from the last year available.

- Adding a component to provide an incentive for continued energy efficiency and distributed generation investment (since measures that reduce retail sales would be disfavored). This component could be based on the EDU's adopted target for EE savings, along with average annual DG installations.
- Multiplying by an emission factor that reflects the cost-burden of generating with emitting resources (e.g. the natural gas default emission factor).
- SMUD recognizes that this concept needs further discussion, but believes that it has promise for widespread acceptance and for automatic coverage with additional allowances for the cost-burden of electrification.

(SMUD)

Comment:

Crediting Utilities for Increased Electrification: SCPPA agrees with ARB staff's recognition that load growth from transportation and other sector electrification efforts will require additional allowance allocations post-2020. As a primary climate change strategy of the State, electrification of multiple other sectors will only serve to increase EDU loads and will need to be addressed accordingly with additional allocation value. But SCPPA is concerned that the issue of Allocation for Increased Electrification merited only one paragraph in the ISOR. This is especially disconcerting since the discussion only mentioned that this is an outstanding issue that needs more evaluation. As noted numerous times, this is a complicated and interdependent regulation, and allocations for known electrification are a key issue. California has clearly stated that one of its overarching climate goals is the electrification of the transportation and goods movement sectors, as is seen in the considerable work on zero emission vehicles (ZEVs) and other forms of electrification. As ARB develops a workable methodology for electrification allocations, SCPPA recommends that it not be overly burdensome or require data that is not readily collected by the utilities. Further, the issue of additional allocations should be clearly understood before the Regulation is finalized.

Staff has repeatedly dismissed the use of the Low Carbon Fuel Standard model for determining the amount of electricity used for ZEVs, but the discussions surrounding the level of rigor desired is more than enough to warrant concern. SCPPA recommends that ARB staff develop a straightforward, data driven methodology for stakeholder review on electrification allocations. SCPPA has already sought the assistance of the CEC to collaborate in development of an estimation methodology. (SCPPA)

Comment:

Lastly, widespread electrification, including the growth of electric vehicles, will play an important role in meeting the State's greenhouse gas targets. The ARB should enable allowances for increased electrification, which is consistent with SB 350's call for widespread vehicle electrification and acknowledgement of the corresponding impact on POU's from such electrification.

CMUA believes these modifications will better enable the success of the Cap-and-Trade Program. (CALMUNIUTILASSOC)

Comment:

Supplemental Allowance Allocation for Electrification

The electrification of the transportation and other sectors of the California economy will be necessary for California to meet its long-term climate goal of achieving an 80 percent GHG emission reduction from 1990 levels by 2050. California has clearly signaled its plans to advance State policies designed to accelerate the electrification of the transportation and goods movement sectors. Electrification is a key priority for LADWP and other EDUs in the South Coast Air Basin. The increased electricity generation needed to power California transportation will necessarily result in increased GHG emissions for which EDUs and ultimately ratepayers will be responsible. The resulting increase in EDU load due to this electrification has not been accounted for in ARB's cost-based EDU allocation methodology. In order to ensure that ratepayers are protected from increased costs associated with electrification, a corresponding increase in allowances allocated to the electric power sector during the post-2020 period is required.

Providing allowances for electrification can help to efficiently meet ARB's complementary policy goals and is consistent with California Senate Bill 350 (SB 350).²⁵ The resulting emission increases in the electric sector due to electrification would be more than offset by substantial GHG emission reductions in other sectors. Providing an allowance allocation for electrification can mitigate the disincentive to invest in electrification.

In the August 2 proposal, ARB recognized this need and expressed its commitment "to evaluate how increased electrification ... for the post-2020 period should be accounted for in the allocation methodology for EDUs."²⁶ LADWP applauds ARB's recognition of this need and supports staff's continuing evaluation of approaches for fairly and effectively incorporating transportation electrification into the cost-based EDU allocation methodology.

LADWP urges ARB to consider methodologies that allocate allowances based on projected emission increases due to projected actual use of electrification infrastructure. These additional allowances would be distributed from an allowance reserve specifically

²⁵ See S.B. 350 § 3 ("The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification").

²⁶ 2016 ISOR at 43.

established for EDUs that present evidence of increased load to meet projected future increases in transportation electrification in each EDU service territory.

To quantify the number of allowances needed by an EDU, the methodology should rely on EDU-specific generation data and emission factors. For generation data, ARB should first utilize a projection of expected electricity demand increases associated with the utility's electrification efforts. ARB could utilize EDU Integrated Resource Plans developed as part of the SB 350 process or CEC electric utility data. The demand, in the case of electric vehicles, could be based on EDU-specific forecasts of electric vehicle penetration in its service territory, average kwh/mi electric vehicle efficiency ratings taken from published U.S. Department of Energy and U.S. Environmental Protection Agency (EPA) data, and mile per year per vehicle information taken from ARB's EMFAC model. For EDU-specific emission factors, ARB should utilize a three year average of each EDU's system-wide emission rate. Quantification could be updated annually.

After estimating an EDU's projected increase in electricity demand (and GHG emissions) due to electrification, ARB would allow the covered EDUs to hold in their accounts sufficient number of allowances to cover their emissions. This amount of each EDU's allowances would remain available to meet the EDU's compliance obligations. Rather than imposing overly burdensome verification requirements,²⁷ LADWP recommends that ARB restrict the ability of EDUs to sell or trade those allowances allocated to cover costs associated with electrification. (LADWP)

Comment:

MID supports the "cost burden" allocation method, but stresses the importance of recognizing the impact of increased vehicle electrification in the allocation calculation. MID supports the cost burden method proffered by ARB for calculating EDU allocation. This method utilizes 2020 load forecasts submitted by Electric Distribution Utilities (EDUs) to the California Energy Commission (CEC) for the Integrated Energy Policy Report (IEPR) process, and then subtracts electricity from 2020 zero-emission energy sources as reported by EDUs pursuant to the S-2 process to determine the amount of energy in 2020 with a compliance obligation. That energy is then multiplied by a natural gas emission factor. The resulting emissions would be known as the cost burden. An individual EDU's allocation would be equivalent to its calculated cost burden as reduced by the cap decline factor each year. While this is a great solution for determining allowance allocation, it is important that the effect of vehicle electrification on EDU loads be factored into the cost burden calculation.

²⁷ While ex post evaluation of investments in electrification infrastructure would be straightforward, it would be extremely difficult to accurately track and quantify whether the forecasted electricity use was realized. For example, electric vehicle owners residing in LADWP service territory may not be charging their vehicles at home or within that service territory. Thus, any verification protocol should not be so difficult to meet as to result in the failure to obtain a Mandatory Reporting Regulation positive or qualified positive verification determination.

2013-2020 allocations were based on load forecasts submitted by the EDUs, which took into account estimates for load increases from vehicle electrification, but the proposed calculation does not recognize the fact that load will increase 2020-2030 as penetration of electric vehicles into the market increases. With state policy set to drive electric vehicle adoption, it is important to recognize the effect this will have on EDU loads. In meetings between the JUG and ARB, ARB has stated that in order to validate load attributed to vehicle electrification, EDU's must be able to supply meter data to support the additional allocation. EDUs cannot force their customers to install or use special meters to measure electric vehicle load, and MID believes that it is counter-productive to place additional requirements on customers seeking to reduce emissions by adopting electric vehicle technology. MID requests that ARB consider the method used in the Low Carbon Fuel Standard program, wherein ARB creates an estimate of electric vehicle charging load using its access to Department of Motor Vehicles data. MID recommends that ARB allow more time to think through the process of recognizing electric vehicle load in the EDU allocation calculation. (MODESTOID)

Comment:

Allocation to EDUs for Increase End-use Electrification:

EDF believes ARB has taken the appropriate step by continuing to consider the question of whether and how to update allowance allocation to EDUs to account for expanded electrification deserves further study and consideration. Driven by decarbonization of the grid, electrification increasingly presents an opportunity for deep carbon reductions in a variety of sectors, most notably the transport sector. As emissions in those other sectors fall, increased demand for electricity will result in greater emissions associated with the electric sector, potentially warranting greater allocation to fund direct investments in decarbonization. That said, it will be critical that allowances are not used to blunt the carbon price signal in electricity rates. Using allowances to distort the price signal in electric rates could potentially disadvantage alternative technologies, leading to higher GHG emissions and delaying (or derailing) critical innovations.

Another potential source of risk in updating allocations to EDUs stems from the method used to update the allocations. If allocation are updated based on changes in load, as opposed to well identified instances of substitution toward electric alternatives (i.e., by measuring the change in electricity demanded by the EV fleet, for example), there is potential to disincentive energy efficiency. That is, if allocation is based on changes in load, as opposed to changes in load driven by specific, and well-quantified, instances of electrification, then EDUs will have a strong disincentive to invest in activities that reduce load. (EDF)

Comment:

We do support an allowance allocation to the electric utilities to support electrification. As was mentioned by CalETC earlier, the utilities will play a key role in making --

achieving the goals of SB 350. And so that allowance allocation would help to pay for the infrastructure and the additional generation that would be needed to support that load. (LADWP3)

Response: The commenters request allocation to EDUs for transportation electrification.

Staff calculated EDU allocations for 2021-2030, as proposed in the first 15-day amendments and amended in the second 15-day amendments, using historical data and generation and load forecasts. Any transportation electrification that has already been accounted for in these forecasts has already been accounted for in allocation calculations.

Insofar as transportation electrification results in load increases and increased Cap-and-Trade Program cost burden beyond these forecasts, as indicated in the 45-day and 15-day notices, staff continues to consider how the load change and resulting cost burden could be accurately calculated for allocation purposes. ARB staff notes that any method would need to be as accurate and verifiable as the methods used to calculate product-based allocation for industrial sectors. It would not need to be calculated in advance of load and cost burden increases, but could be based on actual data with allocation occurring in arrears. Use of actual load and emissions/cost burden increase data can minimize or eliminate the use of estimation. Minimizing estimation will ensure that the allocation is appropriate for actual deployment of electrified transportation. Given the current uncertainties over this deployment/growth, and the value associated with allowances in the limited market of the Cap-and-Trade Program, using actual data for allowance allocation is appropriate. Further, it is important to avoid incentivizing load increases which do not reduce net GHG emissions. Staff will continue to work with stakeholders to identify appropriate data sources to meet the mandate of SB 350 to identify and adopt appropriate policies to remove regulatory disincentives preventing EDUs from facilitating the achievement of GHG reductions in other sectors through increased investments in transportation electrification, including consideration of allocating allowances for increased electrification of transportation. ARB will coordinate with other agencies such as CEC and CPUC as needed.

Some commenters have requested allocation for other causes of increased load besides transportation electrification. As one commenter noted, allocation for load increases not associated with specific causes would risk reducing incentives for energy efficiency. Staff is continuing to discuss transportation electrification insofar as it results in a net decrease in emissions. Consideration of causes of load increase which do not result in emissions decreases would open the broader question of what load forecasts should be used to calculate 2021-2030 EDU allocations. Staff does not anticipate opening this broader question again after the completion of this rulemaking.

One commenter, Turlock Irrigation District, also requests that ARB take into account the “disproportionate burden” this sector bears in reducing emissions. ARB has acknowledged the overlapping GHG-reducing requirements on the electricity sector by not including the cap adjustment factor in EDU allocation calculations, but by using the increase in zero-emissions electricity caused by the RPS Program to reflect that the sector will reduce GHG emissions over time, as discussed further in response to 45-day comments B-1.3.

Allocation and the RPS Adjustment

B-1.11. Comment:

Suggested Revisions to Allocation Approach

If ARB is, nonetheless unable to retain the RPS Adjustment, it should revise its proposed allocation approach to the renewable energy double payment problem to fully account for the level of firmed/shaped renewable energy that EDUs, including POUs, may legally acquire.

First, as outlined above, the number of allowances that ARB has proposed to allocate to EDUs substantially underestimates the number of compliance instruments that may have to be surrendered for zero-emission power purchased by EDUs. To address this issue, ARB should adopt a more realistic methodology for calculating the number of allowances needed to meet compliance obligations for firmed/shaped renewable generation through 2030. One approach that ARB could adopt is to calculate the number of allowances an EDU requires to offset the cost of these overlapping obligations in a way that ensures that the EDU receives enough allowances to actually cover the amount of compliance instruments the EDU will be required to surrender. For example, rather than allocating allowances for this generation as part of the cost-based allowance allocation, ARB could set aside a separate pool of allowances to be distributed to EDUs based on the amount of emissions attributable to firmed/shaped generation that an EDU is permitted under the California RPS program.

Second, ARB's cost-based allocation approach incorrectly assumes that all EDUs may obtain a maximum of 15 percent firmed/shaped renewable generation as part of their RPS compliance. While this limit is accurate for IOUs, it is not an accurate assumption for POUs. As part of SB 350, California applied the RPS to POUs and generally directed the CEC to adopt regulations to implement the RPS for POUs. Consistent with SB 350,²⁸ the CEC adopted regulations that apply the RPS to POUs, including regulations that limit the amount of firmed/shaped renewable power POUs can rely on to meet their RPS obligation. However, unlike for IOUs, for which the 15 percent limit applies to all RPS-eligible renewable power, for POUs, this limit applies only to the “Portion of electricity products procured pursuant to a contract or ownership agreement executed

²⁸ Cal. Pub. Util. Code §399.16(c)(1),(2); Id. § 399.15(b)(2)(B).

on or after June 1, 2010 ."²⁹ That is, any otherwise eligible renewable power procured pursuant to a contract executed before June 1, 2010, can be firmed/shaped even though this renewable energy could increase the total amount of firmed/shaped renewable power above the IOU limit of 15 percent. For example, LADWP has four grandfathered power purchase agreements with out-of-state wind farms with firming/shaping delivery arrangements. These four wind farms produce approximately 1.1 million MWh per year.

To the extent ARB finalizes an allocation methodology to protect ratepayers from the cost of overlapping compliance obligations under Cap-and-Trade and RPS programs, it should do so in a way that accurately accounts for the amount of firmed/shaped renewable generation that a POU is permitted for RPS compliance. For example, ARB could adopt a POU-by-POU determination of the allowable level of firmed/shaped renewable generation, and use that generation to calculate the cost-based allocation for each POU. (LADWP)

Response: In the first 15-day regulatory change proposal, staff proposed to retain the RPS Adjustment, thus negating any reason to allocate to EDUs for RPS Adjustment-associated cost burden. In light of this proposed amendment, the commenter's concern is addressed.

B-1.12. Comment:

The Staff Initial Statement of Reasons indicates that allocations to electric distribution utilities (EDU) will be adjusted after 2020 to account for elimination after 2020 of the Renewable Portfolio Standard adjustment. WPTF supports this approach, provided that it results in equal treatment of all load-serving entities.

WPTF does not believe that the proposed framework for EDU allocation will result in equal treatment of energy service providers and community choice aggregators for the following reasons.

- The process for determining the quantity of allowances allocated to EDUs collectively and individually is not transparent. During the development of the current program, much of the allocation discussion happened in discussions between CARB and EDU behind closed doors. It was not clear how CARB accounted for different factors that impact costs for electricity ratepayers, nor how these factors relate to final EDU allocation quantities. The ISOR indicates that a similar approach will be taken for the post 2020 allocations: "staff proposes to continue allowance allocation to EDUs after 2020 using an approach based in part on the methodology used for 2013-2020 EDU allocations. Under such a proposal, the 2020 expected cost burden for each EDU would be the starting point for calculating post-2020 allowance allocations. Staff would propose to calculate the 2020 emissions cost burden for each EDU using load data from the

²⁹ Cal. Code Regs. Tit. 20, § 3204(c)(4),(8).

California Energy Commission's (CEC) 2015 Energy Demand Forecast (CEC 2016) and resource data from 2015 S-2 forms, supplemented by additional data as needed.”

- It is not clear whether CARB’s proposal to compensate EDUs via allocation for elimination of the RPS adjustment will also take into account ESP and CCA procurement. The ISOR states that the regulation will be modified “to provide each EDU with an allowance allocation that accounts for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California, and eliminate the RPS adjustment from the Regulation.” The ISOR does not indicate whether the allocation related to elimination of the RPS adjustment would also reflect impacts on ESPs and CCAs operating within EDU service territory.

If CARB provides any amount of allocation to EDUs to compensate for elimination of the RPS adjustment, then it is imperative that CARB provide equivalent allowance value to CCAs and ESPs. WPTF recommends that CARB take several steps to ensure that this outcome is achieved.

First, CARB must provide more transparency on the EDU allocation process and explain its methodologies for determining how factors such as changing load and renewable procurement are translated into collective and individual EDU allocations. CARB should also work with EDUs, ESPs and CCAs to quantify the allowance allocation needed to compensate for the elimination of the RPS adjustment.

Second, CARB should identify the proportion of allowances in each EDU allocation that represents compensation for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California.

Third, CARB should provide additional guidance to the CPUC to ensure that a proportional share of allowance value from the EDU allocation flows through to commercial and small industrial customers of ESPs and CCAs, which are not eligible for a direct allocation of allowances. Alternatively, CARB should allow ESPs and CCAs to claim an adjustment equal to the amount/percent allowance allocation EDUs receive in lieu of the RPS adjustment. (WPTF)

Response: In the first 15-day regulatory change proposal, staff proposed to retain the RPS Adjustment, thus negating any reason to allocate to EDUs for RPS Adjustment-associated cost burden. In light of this proposed amendment, the commenter’s concern is addressed.

B-1.13. Comment:

Allowances Should Be Allocated to All LSEs to Ensure Fairness

If the ARB insists on eliminating the RPS Adjustment, the proposed allowances should be allocated to CCAs as well. While the CCAs understand that the intention of this

proposal is to protect electricity consumers, the proposed allocation is flawed and will unfairly impact CCA customers. The CCAs understand that Publicly Owned Utilities (POUs) are able to utilize allowance allocation for the benefits of ratepayers or for compliance of the RPS program. Since the CCAs have the intention to maximize emissions reduction, and as entities that are similar to the POUs that are not beholden to shareholders, it is appropriate to allocate allowances to CCAs.

As explained earlier, the IOUs have the ability to recover their commodity costs through their ERRRA accounts, with oversight by the CPUC. Unlike the IOUs, if the costs of renewable resources rise, CCAs will have to face the difficult choice between reducing the level of renewable procurement or raising their generation rates. Given the growth of CCAs, the impact of increased rates will affect a larger number of ratepayers after 2020.³⁰ To the extent that CCA rates materially exceed those of the incumbent utility, customers would likely opt out of CCA service to receive electricity from the incumbent IOU. As IOU generation is more emissions-intensive, the net result on the climate would be an increase in GHGs.

To ensure that there is a leveled playing field between LSEs, and that there is adequate ratepayer protection for all customers, the ARB should make the allowances available to CCAs. Since CCAs are not direct energy importers, CCAs should have the ability to transfer the allocation to importers based on the volume of electricity purchased. (JOINTCCAS)

Response: The commenters request that ARB allocate allowances to all load-serving entities rather than only to investor-owned utilities (IOU), publicly owned utilities (POU) and electric co-operatives (co-op). Staff declines to make this change.

ARB allocates allowances to electrical distribution utilities rather than other entities in the electricity sector because staff believes this approach maximizes equitable treatment of ratepayers and facilitates the return of value in a way that would maintain the marginal incentive of end-use customers to reduce emissions. Electrical distribution utilities consist of IOUs, POUs, and co-operatives that deliver power to end-use customers. Customers who purchase electricity from community choice aggregators (CCAs) have that power delivered to them by IOUs. ARB allocates allowances for that power to the IOUs. The Cap-and-Trade Regulation requires IOUs to consign those allowances and use them to benefit ratepayers, including equitable treatment of CCA customers and customers who purchase electricity from the IOUs. The California Public Utilities Commission oversees the use of the value of those allowances, including how it is used to benefit ratepayers. This approach generates equitable treatment

³⁰ In addition to the growth in PG&E's service territory, as referenced in Footnote 5, Southern California Edison (SCE) will likely see two-thirds of their loads departing for CCAs in Los Angeles County, Riverside County, and San Bernardino County. See California Energy Markets, No.1401 at page 12. September 2, 2016.

between CCA and non-CCA customers of the same IOUs. If ARB were to remove allowances from IOU allocations and allocate them to CCAs, then it is unlikely that CCA customers would receive the same treatment as IOU customers, who see both a cost pass-through as required by the CPUC, as well as the climate credit. For these reasons, staff has decided to allocate allowances to IOUs on the CCAs behalf.

Inclusion of Industrial Covered Entity Electricity in Industrial Benchmarks and Removal from EDU Allocation

B-1.14. Multiple Comments:

EPUC supports the amendment to include the emissions associated with purchased electricity in the benchmarks for EITE industrial facilities as improving the tracking of all costs associated with an industrial process...

Amendment to Include Purchased Electricity in EITE Benchmarks

Emissions-intensive, trade-exposed covered facilities receive allowance value to mitigate leakage risk based on an ARB-determined direct emissions benchmark for each industry that does not include indirect emissions of electricity purchased from a utility. Instead, those indirect emissions are used by the CPUC to allocate the value of the utilities' monetized free allowances to covered facilities. The amendments propose to include indirect electricity purchase emissions in the emissions benchmarks used by CARB to allocate allowances to cover direct emissions. To avoid duplicating the allocation, CARB will reduce the allocations of allowances to the utilities to remove allowances attributable to covered facility load.

EPUC supports the inclusion of emissions from indirect electricity purchases in the calculation of benchmarks used for the EITE allocations. Combining industry assistance into one allocation by ARB ensures the same methodology is used to allocate allowances for direct and indirect emissions. This approach also ensures timely allocation to address leakage; to date, under CPUC administration, covered entities have not received allocations for any year of the cap and trade program due to delay. Finally, combining direct and indirect emissions allocations reduces administrative complexity by including both allocations in a single process before a single agency...

The Board should approve the amendment that includes emissions from purchased energy in the calculation of the EITE benchmarks. (EPUC)

Comment:

On page 42 of the ISOR, staff discusses allocations for industrial covered entities that purchase electricity. Starting with vintage 2021 allowance allocation, staff proposes to modify the product and energy-based emissions efficiency benchmarks to include emissions associated with purchased electricity. This means that industrial covered

entities will receive allowance allocation directly from ARB to help offset increased electricity costs from the Program.

Recommendation: In our analysis, this is a helpful proposal. ARB says this will have an effect on benchmarks, but there is a lack of specificity on how the impacts will play-out. We look forward to working with staff on this provision. (AGCOUNCIL)

Comment:

NAIMA SUPPORTS DIRECT ALLOCATION OF ALLOWANCES TO INDUSTRIAL FACILITIES

Because of delays related to the California Public Utilities Commission's ("CPUC") processing requirements, CPUC has requested that CARB directly allocate allowances to industrial covered entities to cover the carbon cost associated with their purchased electricity. CARB supports this request because having a single agency distribute this value will ensure that allocation is done in a timely manner and consistent with the regulation. NAIMA supports CARB's consolidation of these responsibilities in to a single agency. (NAIMA)

Comment:

Including Purchased Electricity or Steam in Industrial Benchmarks:

EDF strongly supports ARB's proposal to include purchased electricity and steam in the calculation of industrial benchmarks, and strongly advocates that ARB apply EDU or purchase specific (in cases where an industrial source purchases electricity directly from and EGU, for example) emissions factors. Applying EDU or purchase-specific emission factors will provide the correct economic incentives to industrial sources to substitute between electricity and steam supplied by an EDU, or other third party, and on-site combustion. In contrast, applying a state average emission factor would unduly penalize sources of electricity and steam with emission factors below the state average and unduly advantage sources with emissions factors above the state average, potentially distorting technology choices of covered industrial sources and leading to higher GHG emissions.

ARB should reduce the annual allocation to each EDU by an amount equivalent to the total annual allowance allocation to industrial sources for electricity or steam purchased from that EDU. This netting out should be conducted on an updating annual basis in concert with the allocation to industrial sources for purchased electricity and steam. As opposed to forecasting approaches, which would reduce the allocation to EDUs by projecting emissions associated with purchases of electricity or steam by covered industrial sources, this approach guarantees that allocations to EDUs are appropriately adjusted for net sales, avoiding under or over compensation associated with sales of electricity or steam to covered industrial sources. (EDF)

Response: The commenters express support for removing allocation for industrial covered entities' use of electricity from EDU allocations and, in a future rulemaking, adding it to industrial allocations.

Instead of updating allocations to EDUs based on actual industrial covered entity load served by each utility, as EDF suggests, staff proposes to remove load associated with covered industrial facilities based on historical electricity purchased from each utility. Staff's proposed approach enables ARB to provide EDUs with certainty regarding their 2021-2030 allowance allocations and believes the EDF suggestion does not make sense in the context of industrial benchmarks, which are based on historical data.

As indicated in the Second 15-day Notice of Public Availability of Modified Text, staff plans to add allocation for use of electricity to industrial covered entity benchmarks before vintage 2021 allocation occurs. Further, staff plans to use utility-specific emission factors in either the updating of the benchmarks or in the actual allocation itself, depending on stakeholder feedback.

B-1.15. Multiple Comments:

The JUG observes that ARB Staff has proposed in workshops this year to discontinue the allocation of allowances to electric utilities for emissions associated with electricity use at covered industrial facilities, and instead allocate allowances directly to those facilities to reflect the carbon cost "burden" in electricity prices. JUG members believe that the change is unnecessary now that the CPUC has developed a process for returning cap-and-trade revenue to EITE entities. Such a change would also complicate the pass through of GHG costs to industrial customers of POU's because these EITE entities already benefit from the use of POU cap-and-trade allowance value and it is infeasible to establish a separate rate for EITE entities. (JOINTUTILITIES)

Comment:

Shifting EDU Allowance Allocations to the Industrial Sector

ARB has proposed to discontinue the allowance allocation associated with energy used at "energy intensive trade exposed" (EITE) facilities to EDUs and instead allocate allowances to EITE facilities representing their electricity consumption using a formula that includes Product-Based Benchmarks (PBB). ARB's stated purpose of this reallocation of allowances is to mitigate electricity cost increases for Cap-and-Trade Regulation compliance costs that would otherwise be borne by EITE sources by providing this supplemental allocation of allowances directly to those sources.

Specifically, ARB has proposed to:

...exclude the emissions associated with electricity sold to industrial covered entities from the calculation of each EDU's 2020 emissions cost burden, calculated using the

average annual industrial covered entity purchased electricity from 2013 and 2014 data reported through MRR and an EDU-specific emission factor.³¹

LADWP believes that ARB's proposal is unlikely to accomplish ARB's goal of leakage prevention. For these reasons, ARB should retain the current approach and not shift any allowances from EDUs to EITE sources.

(A) Shifting Allowances to EITE Sources is Unnecessary to Prevent Leakage

ARB has justified its proposal to shift allowances from EDUs to EITEs, in part, in order to "create a level playing field" between investor-owned utilities (IOUs), which are subject to California Public Utilities Commission (CPUC) oversight, and publicly-owned utilities (POUs), which are not. However, this is based on the inaccurate assumption that merely because POUs are not subject to CPUC oversight, they are not obligated to ensure that allowance value flows to ratepayers, including covered industrials (EITE sources). POUs are structured differently from IOUs. First, LADWP and other POUs are subject to local governmental oversight, in lieu of the CPUC regulation that has traditionally applied to IOUs. Second, LADWP and other POUs operate for the exclusive benefit of their retail ratepayers and own and operate a majority of their generation assets on behalf of their ratepayers. For example, LADWP is accountable to the Los Angeles City Council to provide reliable, affordable and clean electricity for its ratepayers. City Council oversight ensures that electricity costs are kept low, and that, whenever possible, important employers in the community such as those that operate EITE sources do not face financial pressure to leave.

Vertically integrated POUs, such as LADWP, use their allocated allowances directly to cover their compliance obligations. Thus, under the current electricity cost-mitigation approach for EITE sources, all of LADWP's ratepayers (including EITE sources) receive the financial benefit of the GHG emission allowances allocated to LADWP. In effect, LADWP is providing leakage protection to covered EITE customers to the fullest extent practicable by providing the lowest possible electricity costs to those customers, enabled by the allowances allocated to LADWP for that purpose.

(B) ARB's Proposed Methodology for Redistributing Allowances to EITE Facilities will Undermine its Leakage Prevention Goals

It is LADWP's understanding that ARB intends to deduct from its otherwise-cost-based EDU allocation a number of allowances based on the amount of electricity sold by LADWP to EITE facilities in its service territory and LADWP's specific emission rate. As mentioned above, the EITE facilities would receive allowances based on a formula that includes PBBs. The difference in allowance allocation methodologies results in a transfer of allowances from the EDUs to EITE facilities that would not be on a one-to-one basis.

³¹ ISOR at 43.

ARB's proposal does not include a specific methodology for calculating the number of allowances that would be *distributed to* EITE facilities in our service territory. However, some elements of the proposal suggest that ARB's approach would be less effective at reducing leakage related to increased electricity costs than the current framework for leakage prevention that POUs provide (that is, avoiding rate increases). Specifically, the proposal states that "staff is proposing to allocate to all industrial covered entities for the sector-specific emissions associated with purchased electricity *regardless of electricity supplier for the industrial covered entities*."³² This language suggests that while ARB will deduct from EDUs a specific number of allowances that is based on the EDU's emission intensity, ARB will not redistribute those allowances to each EITE entity based on the emission intensity of the EDU that serves it. Such an approach, if adopted, would significantly undercut the "leakage prevention" goal that is currently being met by the cost-based EDU allocation. EITE entities that are located within EDU service territories with a lower than average carbon intensity will be long on allowances distributed to cover their actual electricity carbon costs. In contrast, covered trade-exposed industrial entities that are located in EDU service territories with a higher than average carbon intensity will be short on allowances distributed to cover their actual electricity carbon costs.

If ARB proceeds with this approach, EITE facilities within LADWP's service territory would not receive enough allowances through the benchmarking method to cover the actual carbon costs of the electricity they consume. LADWP estimates that EITE facilities located within LADWP's service territory would experience an increase in the cost of doing business in California ranging from \$100,000 to \$400,000 per year. In aggregate, the increased cost to all EITE facilities within LADWP's service territory would be over \$1 million per year. This is a conservative estimate based on the average annual electricity kWh consumption of EITE facilities, the California average electricity emission rate (calculated using 2015 Total System Power as reported by the California Energy Commission (CEC) and the eGRID2012 GHG Annual Output Emission Rate for subregion CAMX), LADWP's 2015 average electricity CO₂ intensity rate, and the current auction floor price of \$12.73 per metric ton. The actual cost will increase over time as the cost of allowances increases.

Even if LADWP purchased all of the allowances allocated directly to the EITE entities in its service territory for the purpose of offsetting electricity cost increases, LADWP would face a substantial shortfall in allowances needed to make up for the number deducted from the EDU allocation. This cost would either be borne by the EITE entities, causing additional leakage, or by all LADWP ratepayers (including low income customers), undermining the purpose of the cost-based EDU allocation.

Therefore, the current approach to mitigating electricity cost increases for EITE facilities (and therefore limiting leakage) is preferable to the method proposed by ARB, as it avoids cost increases to EITE facilities (and therefore limits the potential for leakage)...

³² 2016 ISOR at 34 (emphasis added).

The failure to adopt an alternative approach to either EITE allocation or EDU deduction will result in additional leakage and potentially the loss of significant businesses in LADWP's service territory. (LADWP)

Comment:

The California Public Utilities Commission (CPUC) chose to require that IOUs return allowance value to industrial entities using product and energy-based benchmarks comparable to ARB's benchmarks. This process was very slow to implement, and so the according to ARB Staff, the CPUC requested that ARB directly allocate allowances to industrial covered entities to cover the carbon cost associated with their purchased electricity.

The Board should reject this request. Now that the CPUC has developed the calculation process and will be delivering the EITE allowance value in October 2016 for the years 2013 through 2016, there is no benefit to shifting the calculation back to ARB and potentially causing a second, long delay due to the complication of figuring out POU and electrical cooperative industrial covered entity return calculations. This is a complicated issue given that POUs and electric cooperatives do not have to reflect the full GHG cost in rates and the potentially large number of entities with different calculations (there are 46 POUs and electric cooperatives).

SDG&E Recommendation: The Board should reject this proposed change that is being considered by Staff (though not in this set of proposed changes) regarding EITE allowance return for indirect electricity emissions or should restrict it to the EITE customers of the IOUs so as not to delay future returns to EITE customers. (SDGE)

Comment:

Industrial Allowance Allocation Related to On-Site Electricity Use:

SMUD opposes the proposal to reduce EDU allocations in relation to the amount of electricity supplied to industrial covered entities being served by each EDU. The intent of providing administrative allowances to EDUs was for ratepayer protection, to cover the obligations the EDUs pass on to their customers (in addition to the costs of complementary programs). EDU ratepayers include industrial covered entities, who deserve the same ratepayer protection as other customers. There is no reason to shift the allowances for this purpose from the EDUs to their industrial customers.

With regard to IOUs, the process at the CPUC for determining how to return allowance revenue to industrial customers has been complicated to develop. However, that work has now been completed and industrial covered entities will now receive bill credits or rebates from allowance sales, just like residential customers. Accordingly, there is no need to develop a new way to compensate these customers through a dramatic shift to an entirely new structure for treatment of EDU and industrial sector allocations. Such a change is not necessary or prudent. It could cause delays in getting compliance costs

related to electricity prices returned to EITE entities, particularly for industrial covered entities in POU service areas.

POUs already return compliance costs to these industrial customers through lower electricity rates, and changing policy now would require POUs to change rates for industrial covered customers. Thus, implementing a new structure for POUs (and IOUs) as proposed will lead to new processes and could cause market uncertainty among industrial entities about how their costs may be "covered" or reflected going forward.

The staff proposal does not provide industrial customers with the same protection from Cap-and-Trade costs because a direct award of allowances won't necessarily cover all of their costs. Thus, the goal of keeping these businesses in California may not be met by this regulatory change. Consequently, the current design should be maintained for the following reasons:

Fairness and simplicity. All industrial customers have costs covered with the same structure, as opposed to one structure for covered entities and another for non-covered entities;

The staff proposal would not cover actual carbon costs imbedded in electricity rates and returned to all customers (for POUs) as changes in the electricity mix change those costs over time.

The current system reflects the cost differences between service areas in the state, the staff proposal does not - hence, the staff proposal may lead to unintended movement of industrial customers among utilities with no benefit to the atmosphere.

It will be difficult to equate new industrial customer allowances with their actual emissions, which could lead to surplus allocations. Under the proposed rule, industrial customers have no obligation to use those surplus revenues for AB 32 purposes, thus depriving the State of an important source of funding for carbon reduction.

In summary, SMUD opposes removing allowances from the EDUs and providing a related amount of allowances to covered industrial entities. The proposal is complicated and unnecessary. (SMUD)

Comment:

The ARB Should Not Reallocate Cap-and-Trade Allowances From POU Electric Distribution Utilities to Emissions Intensive Trade Exposed Industries.

The Proposed Amendments would reallocate a certain amount of allowances from EDUs to Emission Intensive Trade Exposed ("EITE") industries. TID does not support this proposal and does not agree with the two main rationales supporting the reallocation. First, we do not agree that customers in POU service territories are at a disadvantage to similarly situated customers in IOU service territories. While POUs do not have a requirement to return allowance revenue to EITE customers, many POUs, including TID, have undertaken substantial efforts to use the freely allocated allowances

for the benefit of all their customers, EITE included. Many POU's may place allowances directly in their compliance account, thereby offsetting the costs of procuring allowances they would otherwise pass on to customers. POU's may also apply allowance revenue to programs that reduce GHG emissions and offset other regulatory costs (e.g., the RPS). We do not believe there is nor have we seen any evidence to support the contention that EITE customers in POU service territories are at a disadvantage to IOU customers.

Finally, the reallocation proposal would create a significant rate issue for POU's. Unlike IOU customers that will simply stop offering rebates and continue to pass on all allowance procurement costs, POU's will continue to use their allowances for compliance or for programs that benefit all customers. EITE customers will effectively benefit twice from the Cap-and-Trade (once through free allocation and again from the POU's use of freely allocated allowances). This situation will create a disparity among the POU's ratepayers. For these reasons, the ARB should not reallocate allowances from the electricity sector to EITE entities. (TURLOCKID)

Comment:

EDUs Allowance Allocation Should Not be Adjusted for Covered Industrial Customers' Purchased Electricity

The Staff Report proposes to exclude the emissions associated with electricity sold to industrial covered entities from the calculation of each EDU's 2020 emissions cost burden, calculated using the average annual industrial covered entity purchased electricity from 2013 and 2014 data reported through MRR and an EDU-specific emission factor. These quantities are reduced by the cap decline factor for 2020, and then subtracted from the 2020 cost burden. The resulting total allocation is decreased on an annual basis with the cap adjustment factor. (Staff Report, p. 43) NCPA joins with the rest of the Joint-Utility Group in noting that this proposed change is unnecessary. This proposal presents a significant shift in the current policy and should be rejected. As CARB found in 2011,

"Allocation to electricity utilities was chosen as the preferred method to return the allowance value to those affected by this program. Because most industrial facilities and Californians use electricity, returning allowance value via electricity utilities is the best alternative to reduce the cost burden of this program. We modified the regulation to include 95892 that demands electric utilities use allocation value to benefit ratepayers, which includes both industry and Californians."³³

NCPA urges the Board to retain this policy preference.

NCPA understands that CARB is looking for a way to respond to the industrial covered entities' concerns about the past delay in the CPUC distribution of allowance proceeds to investor owned utilities' (IOUs) covered industrial customers, as well as what Staff

³³ 2011 FSOR, p. 567

has characterized as the potential for inconsistent treatment of energy-intensive, trade-exposed (EITE) covered entities in POU versus IOU service territories. However, while the initial delay in the CPUC's process for returning allowance value was one of the precipitating factors for this proposal, that should no longer be an issue moving forward, as the CPUC has now established the process and methodology for returning the allowance value and will be able to do so without delay in the future.

The Staff Report also notes that

“Having a single agency distribute this value will ensure that allocation is done in a manner that is timely and consistent with the Regulation, and will ensure that POU and electrical cooperative (co-op) industrial covered entities are provided the same leakage protection as IOU customers (as no regulations or statutes require leakage protection for POU and co-op industrial customers). Staff has seen inconsistent carbon cost compensation for covered industrial entities that are customers of POUs and electrical co-ops compared to customers of IOUs (as noted in the annual EDU use of allocated allowance value reporting required pursuant to section 95892(e) of the Regulation).”³⁴

However, to the extent that this change would only impact EITE entities that are also covered entities, even this proposal will not result in absolute uniformity across all EITE entities in differing service territories. Furthermore, the use of allowance value form is not the sole measure by which to determine the extent of carbon cost compensation for covered industrial customers. NCPA member EDUs have multiple approaches to spread the allowance benefit for covered industrial customers, including value reflected in utility rate structures. Adjusting the allocation of allowances for purchased electricity in the manner proposed would not result in the optimum benefit to the utility's EITE customers. All EDUs are required to use the value of their allocated allowances for the benefit of electric customers; the form of that allowance value need not be the same across all utility service territories. NCPA is also concerned that the methodology proposed for determining the number of allowances to credit to industrial customers differs from the projections that are contemplated for determining the allowances adjustments for EDUs. As such, the reduction in electricity sector allocations will not align with the industrial sector electricity purchases for which EDUs will not receive allowances. NCPA asks that the Board instruct Staff to retain the existing policy. (NCPA)

Comment:

Also, they ARB should continue direct allocation to EDUs for electricity sold to industrial-covered entities. Allocation to EDUs was chosen as the preferred method to return the allowance value to customers, as was noted in the 2011 FSOR. And EDUs remain well situated to utilize allowance value for ratepayer benefit. (CALMUNIUTILASSOC)

³⁴ Staff Report, p. 33

Comment:

MID opposes direct allocation to covered industrial entities for electricity use. The Proposed Regulation Order seeks to reduce direct allocation to EDUs by an amount commensurate with the emissions attributed to electricity purchased by Cap-and-Trade covered industrial entities, and instead supply those allowances directly to the covered industrial entities while the compliance obligation remains with the EDU. ARB stated two reasons for the proposal in its August 2, 2016 Initial Statement of Reasons: 1) inconsistent carbon cost compensation for covered industrial customers of POU's compared to customers of Investor Owned Utilities ("IOUs"); and 2) relief of administrative burden on the California Public Utilities Commission ("CPUC").³⁵ MID contends that the first reason is a non-issue and the burden stated in the second would merely shift from the CPUC to ARB and the POU's.

The value of MID's allocated allowances reduces the impact on its ratepayers from Cap-and-Trade compliance costs and above-market renewable energy procurement for compliance with the RPS program. With help from allocated allowance value, MID has not raised its energy rates since 2011. Industrial entities within MID's service territory are situated at least as well as their peers within IOU service territories for protection from emissions leakage. Electricity sales to the three covered industrial customer facilities within MID's service territory represent approximately 10% of MID's total annual retail energy sales. In 2015, the allowance value allocated to MID in association with the covered industrial customers' electricity use was valued at \$1.5 million. If this value is allocated directly to the industrial customers in the future, it will be necessary for MID to create special rates for these three customers to reassume the allowance value to cover the compliance obligation for their electricity use and avoid having the bulk of MID's ratepayers shoulder the cost of the covered industrial customers' emissions. Additionally, since a portion of MID's allowance value is applied for purposes that provide system-wide emissions benefits, MID will need to reflect in the covered industrial entities' rates that they have not contributed towards the cost of those emissions-reducing expenditures and ensure that they do not receive a double-benefit formed of the other ratepayers' allocated allowances and allowances directly allocated to the industrial entities by ARB.

Ratemaking would be further complicated if the covered industrial facilities only receive allocation for electricity usage related to the processes within their operation that produce on-site emissions, even if the entire facility produces only the covered product. If this were the case, not only would these customers need to be treated differently from other industrial customers, but these customers' load would need to be treated differently within each customer's bill. For example, a facility may only report 50% of its electricity usage as supporting the processes that are listed in Table 9-1 of the Cap-and-Trade Regulation (i.e. excluding office load, product conveyance, facility cooling, etc.), which would mean that the POU receives allocated allowances for a portion of the

³⁵ Staff Report: Initial Statement of Reasons, August 2, 2016, California Air Resources Board, p. 33

covered industrial customer's load and the customer receives allocated allowances for the remainder of their load. It would be very difficult for both the industrial customer and the POU to accurately meter the energy used for these different processes.

Rate setting is a difficult and lengthy process, and the targeted nature of these rate changes could result in rate disparity among facilities producing similar products in a very close proximity, potentially inducing local economic and emissions leakage. It seems unnecessary to remove a burdensome process from the CPUC and place a burdensome process on affected POUs. MID recommends that EDUs receive allocation to reduce the cost burden for all load for which they generate electricity, including load from covered industrial entities. (MODESTOID)

Comment:

Shifting of Electrical Allocation Value to the Industrial Sector. This proposal is a 'solution' that creates five-fold concerns for publicly-owned utilities without practically solving the perceived problem. There are numerous issues associated with trying to separate out Cap-and-Trade regulated entities from not only other industrial ratepayers, but also from other customer classes. Ratemaking can be a multi-year process in POU territories. The time and effort needed to complete such ratemaking would surely be in continual arrears to what the price of carbon actual is in the market. Therefore, it would be very difficult to provide the signals ARB staff believes can be sent. In addition, this issue could result in disproportionate impacts among publicly-owned utility and investor-owned utility customers. As public entities, it would be especially burdensome or nearly impossible for POUs to comply with the requirements of Proposition 26. SCPPA is opposed to this concept and recommends ARB staff not pursue this issue. (SCPPA)

Comment:

Next, I'd like to touch on allowance allocations. And with respect to those, SCPPA does not support the shift of allowance allocation to essentially move directly to allocations for industrial entities. In practice, this would require POUs to go forward with lengthy rate-making processes. And sometimes these are multi-year processes.

So our concern is that in getting there, we would be impacting all of our customers and not just a small number of covered entities.

We recommend that at this time ARB not pursue this shift for industrial allocations, as it would have costly impacts, and may not actually effectively address staff's concerns with that proposal. (SCCPA2)

Comment:

MID also echoes the comments made by Ms. Taheri [SCPPA2] regarding the not supporting the direct allocation of allowance -- allowances to industrial customers. The - that elimination would create the potential for a special rate for a handful of industrial

customers. And that project and that approach would be difficult and create potential legal and implementation hurdles.

So we urge reconsideration of that proposal. (MODESTOID2)

Comment:

First, I'd like to address the proposal to decrease the allowance allocation to the electric utilities and give those allowances to the industrial facilities. The publicly-owned utilities they use those allowances to avoid rate increases to their customers. And so all of our customers benefit from the allowances that ARB allocates to the publicly-owned utilities.

We ask that ARB not adopt the proposal to shift those allowances away from the electric utilities, because the redistribution to the industrial facilities will not make those facilities whole. According to our calculations, the proposal would result in a net cost increase of over \$1 million per year to the handful of industrial -- covered industrial facilities that are within our territory. And that is contrary to the objective, which is leakage protection.

So you're supposed to be protecting these customers from leakage, but yet the proposal from staff would actually increase their cost of doing business in California. So we request that you not adopt that. (LADWP3)

Comment:

We also -- are worry -- are concerned with the switching of the industrial allocation to -- from the utilities to the industrial sector. Especially for POUs, that doesn't adequately compensate or work for our ratepayers. (TURLOCKID3)

Response: The commenters express opposition to removing allocation for industrial covered entities' use of electricity from EDU allocations and adding it to industrial entity allocations. Staff declines to make the requested changes and has moved forward with the removal of allocation associated with industrial covered entity electricity purchases from EDUs and plans to propose (in a future rulemaking) benchmarks that incorporate the emissions associated with industrial covered entities' electricity purchases. Having a single agency--ARB--distribute this value to all industrial covered entities will help ensure that allocation is done in a manner that is timely and consistent with the Regulation, and will ensure that industrial covered entities in publicly owned utility (POU) and electrical cooperative (co-op) territory are provided the same leakage protection as IOU customers. This will help ARB ensure that the AB 32 mandate to prevent emissions leakage is further fulfilled for these entities.

Staff has observed inconsistent Cap-and-Trade Program cost compensation for industrial covered entities that are customers of POUs and electrical co-ops compared to customers of IOUs. It is true that some POUs and electrical co-ops have developed a return of proceeds (or no pass-through of Cap-and-Trade

Program costs) to industrial covered entities, but there remains inconsistent adoption. ARB staff disagrees that the amendments are unlikely to accomplish ARB's goal of leakage prevention in that this method of allocation will assure more consistent leakage protection for IOU, POU, and co-op industrial customers, in alignment with the emissions efficiency benchmarks that are already implemented. These benchmarks include the greenhouse gas emissions associated with steam consumed on site (including steam purchased from off-site) and electricity produced and consumed on site.

Staff recognizes that neither ARB nor CPUC have jurisdiction over the rates set by POUs or co-ops. We understand that these utilities operate at the behest of their customers; however, POUs/co-ops may need to initiate a rate structure that passes down a carbon cost to consumers similar to the IOUs. This decision is solely up to the POU and co-ops themselves, and the proposed regulation changes include no mandates or stipulation on rates for these entities.

Staff also notes the regulatory amendments prohibit volumetric return of allowance value and that staff has expressed through the notices of this rulemaking an interest in considering future regulatory amendments to require POU allowance consignment. If that change occurs in the future, POUs that have been providing leakage prevention to their customers on a volumetric basis would not be able to continue doing so. Shifting the POU allocation for their large industrial customers to those customers directly saves POUs from having to design their own benchmarks or other non-volumetric methods of appropriately distributing allowance value to large and diverse covered entities.

Several commenters noted that the proposal does not address industrial entities served by POUs and co-ops with potential leakage risk that are not covered entities under the Cap-and-Trade Regulation. Staff recognizes that the amendments do not address these entities, but notes that, because the Cap-and-Trade Regulation establishes no direct relationship with these entities, ARB is unable to address emissions leakage for these entities. Staff would welcome further discussions with POUs and co-ops to determine how these EDUs can best help prevent emissions leakage.

Staff also reiterates, as noted in the ISOR, that CPUC staff requested that ARB oversee the distribution of EDU-allocated allowance auction proceeds to all emissions-intensive, trade-exposed entities served by investor-owned utilities (as is required of CPUC by Senate Bill 1018 (SB 1018, Statutes of 2012)). This is the same situation discussed in the paragraph immediately above, in which the Cap-and-Trade Regulation does not establish a direct relationship with non-covered industrial entities, so overseeing proceeds distribution to these entities is not appropriate. However, because the Cap-and-Trade Program regulates industrial covered entities, we can oversee allocation to industrial covered entities.

Contrary to some commenters' concerns, staff does not believe that this proposal will result in significant losses to EDUs or industrial covered entities. This proposal redistributes some allowances from EDUs to the industrial covered entities. Staff finds the analysis by LADWP to be inaccurate, as it does not recognize the complexity of product- and energy-based benchmarks, which are calculated based on all covered entities in California operating within an industrial sector, not on the entities located within certain EDU service territories. Staff will work with industrial covered entities to develop updated benchmarks for a future rulemaking to include the emissions associated with electricity purchases. During that future rulemaking, staff will seek public input and review how EDU-specific emissions intensities can most appropriately be reflected in benchmarks and allocation.

In response to SMUD's comments, the proposed changes to the Regulation continue to allocate to EDUs for the purpose of ratepayer protection as well as allocate to cover the cost burden associated with non-covered industrial entities for leakage prevention. The shift of allowances from EDUs to industrial covered entities does not preclude either of the allocation purposes, but gives ARB more control to guarantee all industrial covered entities receive leakage protection for electricity purchases.

Staff acknowledges the request that the balance of allocation provided to industrial covered entities that receive allocation calculated with an assistance factor less than 100 percent be provided to the EDU. In these cases, staff deems it appropriate to remove the entire historical load associated with these facilities from the EDU's load assumption that determines allowance allocation because the lower assistance factor is an indication that these entities do not require higher levels of allocation to prevent emissions leakage, and therefore it would be inappropriate for the State to provide allowances to any entity to cover the emissions associated with that load.

In response to SCPA's comment regarding the Proposition 26 burden of ratemaking in this context, ARB notes that SCCPA has not explicitly articulated how it would be, as SCCPA asserts, "nearly impossible for POU's to comply with the requirements of Proposition 26." ARB further notes that the Proposed Amendments do not create any additional burden on any POU's ratemaking process. While each POU may be subject to Proposition 26 for any ratemaking process that increases rates or charges a fee, such rate increase or fee could likely be designed in a manner to be considered a non-tax charge and, thereby, avoid the two-thirds vote requirement of Proposition 26.

B-1.16. Multiple Comments:

Direct allocation to industrial customers must leave all parties whole. ...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 (PG&E)

Comment:

However, if ARB nonetheless insists on moving forward with its proposal to increase the industrial allocation level for EITE facilities, it is important that it use a benchmark method based on individual EDU carbon intensity (rather than a statewide benchmark for carbon intensity). Alternatively, an even simpler approach would be first to calculate the number allowances in each EDU territory that will be allocated to EITE entities for purchased electricity, and then to reduce each EDU's allocation by that amount. This alternative approach ensures that there would only be a 1-for-1 reduction in EDU allocation for every extra allowance that EITE entities in that service territory receive. However, it would likely require ARB to delay implementation of this change until such time as it is able to determine the appropriate allocation of allowances for each EITE facility. (LADWP)

Response: The commenters request that ARB use specific methods to calculate allocations for industrial electricity use. The first commenter requests that the amount of allowances allocated to industrial entities for this reason equal the amount subtracted from utilities for this reason. The second commenter provides alternative requests: that EDU-specific emission intensities be used to create EDU-specific industrial benchmarks, or that the amount of allowances allocated to each EITE entity for its electricity use be the amount that is subtracted from the EDU which provides that electricity.

The commenter's suggestion would represent a significant departure from ARB's one-product, one-benchmark policy. As such, staff declines to make this suggested change.

Though the amounts by which post-2020 EDU allocations are reduced to account for industrial covered entity load (which is based on 2013 through 2015 industrial covered electricity purchases) will not exactly match the industrial covered entity load used for updated benchmarks (staff proposed changes to MRR to ensure that electricity data are checked by verifiers for accuracy, and plans to use these data in updated benchmarks to the extent feasible), these values are likely to be close. Staff sees no justification for or need to make these values exactly equal, especially in cases where it would result in over allocation to those entities not deemed to be at the highest risk of leakage.

B-1.17. Comment:

Purchased Electricity/Indirect Emissions

Under the current framework, CARB calculates benchmarks using only direct emissions and steam purchases. For indirect emissions, the CPUC determines how the utilities distribute compensation to eligible entities. (D.14-12-037). According to CARB, the proposed changes will update benchmarks to include the emissions for electricity purchases, same as they do with emissions for steam purchases in calculating benchmarks and make CARB, not the IOUs and POUs, the distributors of compensation (allowances) to eligible entities for indirect emissions.

CLFP has worked with staff on its proposed changes regarding accounting for indirect emissions /purchased electricity. CLFP originally opposed this proposal under the belief that this would eventually be added to a facilities compliance obligation. Staff indicated that that was not the case and that the proposal would not increase obligations.

CLFP sees the benefit of the utilities no longer distributing compensation to covered entities in their service territories. But CLFP needs more assurances that the proposed changes to the benchmark are not significant and will not result in a greater financial impact in the future than CARB suggests. CLFP needs additional clarification regarding the changes to the benchmark, specifically a formula or other methodology that will allow covered facilities to determine any potential financial impacts. CLFP looks forward to further discussion on this proposed amendment with CARB.

As for the distribution of the compensation to covered entities, CLFP also recommends that CARB provide covered entities with an option to take either allowance from CARB or a check/bill credit from energy supplier. (FOODPROCESSORS)

Response: This comment is outside of the scope of this rulemaking. ARB staff has proposed no amendments to place a compliance obligation on industrial covered entities for purchased electricity. The Regulation continues to place the compliance obligation on the electricity generators or importers from which industrial covered entities purchase electricity.

The commenter requests that ARB engage with stakeholders and ensure that thorough electricity consumption data is collected for use in developing benchmarks which include electricity use. As indicated in the Second Notice of Public Availability of Modified Text, staff will propose benchmarks as part of a future rulemaking and will engage with stakeholders through that process. Under MRR, covered entities submit data on electricity they purchase or receive, and staff would solicit any further data it deems necessary for developing benchmarks which include electricity consumption.

B-1.18. Comment:

Allocation of allowances for Purchased Electricity

Air Products supports the revision of the product-based benchmarks to take into account the emission footprint of the electricity required in the production process. We agree this is a more transparent method to ensure the value of the allowances allocated

to the distribution utilities is returned to large electricity consumers, particularly those which experience material leakage risk. Air Products encourages ARB to ensure the proper electricity consumption data is included for ALL producers of a product, including electricity supplied through customer/supplier relationships, when developing the additional benchmark component. Even more so that the discussion regarding proposed changes to the Assistance Factors noted above, changes to the benchmark values are fundamental to the competitiveness of industrial suppliers. ARB should engage in robust stakeholder engagement and not rely upon a 15-day comment period for such impactful rulemaking. (AIRPRODUCTS)

Response: Thank you for the support. As indicated in the Second Notice of Public Availability of Modified Text, staff will propose benchmarks as part of a future rulemaking and will engage with stakeholders through that process. Under MRR, covered entities submit data on electricity they purchase or receive, and staff would solicit any additional data it deems necessary for developing benchmarks which include electricity consumption.

B-1.19. Comment:

NAIMA makes the following requests for clarification in the final regulations:

1. NAIMA requests CARB to state whether purchased electricity will impact the benchmark.
2. NAIMA requests that the calculation method used to determine all aspects of the benchmark be disclosed in advance. (NAIMA)

Response: This comment is outside of the scope of this rulemaking. As indicated in the Second Notice of Public Availability of Modified Text, staff will propose benchmarks as part of a future rulemaking and will engage with stakeholders through that process. These benchmarks will include the emissions associated with purchased electricity. Under MRR, covered entities submit data on electricity they purchase or receive, and staff would solicit any additional data it deems necessary for developing benchmarks which include electricity consumption.

B-1.20. Comment:

VIII. NAIMA SUPPORTS RETENTION OF ORIGINAL THRESHOLD

NAIMA strongly urges CARB to preserve the original regulatory threshold limit of 25,000 tons of greenhouse gas emissions. NAIMA's members are reporting indirect energy used by their facilities. NAIMA urges CARB to not consider indirect emissions as part of the total emissions used to determine whether the threshold has been met or exceeded. Such a measure would be extremely burdensome to NAIMA's companies and could lead to increased production costs. It would also not reflect the energy efficiency savings from the use of fiber glass products in the insulation industry. If CARB is truly

committed to stopping leakage from California, it will provide assurances to industry that indirect emissions will not be used to calculate total emissions. (NAIMA)

Response: Thank you for supporting the regulatory threshold limit of 25,000 metric tons of greenhouse gas emissions. See Comment C-2.2 in Chapter IV for information on the threshold.

In response to the request to not consider indirect emissions as part of an entity's covered emissions, this comment is outside of the scope of this rulemaking. Further, ARB staff has not proposed any amendments to place a compliance obligation on industrial covered entities for purchased electricity. The Regulation continues to place the compliance obligation on the electricity generators or importers from which industrial covered entities purchase electricity.

Use of Allocated Allowance Value

B-1.21. Comment:

Prohibiting volumetric return

We strongly support staff's proposal to prohibit a volumetric return of allowance value for all EDUs starting in the third compliance period, mirroring the prohibition already in effect for natural gas suppliers.³⁶ While the California Public Utilities' Commission revenue allocation framework eschews volumetric returns in favor of lump-sum Climate Credits for customers of the investor-owned utilities, volumetric rate reductions are occurring with a portion of the allowance value allocated to the POUs.³⁷ Moreover, as we argued in 2013, ARB is well within its legal authority to prohibit a volumetric return without infringing on the CPUC's authority to set customer rates.³⁸ (NRDC)

Response: The regulatory amendments implement the requested changes. Thank you for the support.

B-1.22. Multiple Comments:

LADWP has previously been concerned about ARB proposals implementing a requirement that allowance proceeds be provided to ratepayers on a non-volumetric basis. In its March workshop, ARB staff appeared to indicate their intent to propose restrictions on the use of "allowance value" to provide volumetric—that is, rate-relief to customers. LADWP was concerned that this requirement, if applied to all "allowance value," could limit the ability of vertically integrated POUs, such as LADWP, to utilize allocated allowances for meeting their compliance obligation in the least-cost manner.

³⁶ § 95893(d)(3)

³⁷ "Summary of Vintage 2013 Electrical Distribution Utility Allocated Allowance Value Reports," at: <http://www.arb.ca.gov/cc/capandtrade/allowanceallocation/edu-v2013-allowance-value-report.pdf> (figure 2, p.7).

³⁸ "NRDC and Coalition for Clean Air Comments on ARB's Proposed Amendments to the Cap-and-Trade Program," October 16, 2013.

To that end, LADWP supports ARB's more precise drafting of the proposed requirement that "allowance auction proceeds" be provided to ratepayers on a non-volumetric basis.³⁹

This proposed language clarifies that POU's may continue to use allocated allowances directly for meeting their Cap-and-Trade compliance obligations, which provides general rate relief to ratepayers.

LADWP also urges ARB to clarify that the use of allowance auction proceeds to fund energy efficiency and clean energy projects would constitute a non-volumetric use of those proceeds. It would be administratively burdensome to require that POU's—which consign relatively few allowances to auction—provide the limited proceeds obtained at auction to ratepayers as a lump sum bill credit. Rather, it would be more effective and impose less administrative cost for that money to be invested in energy efficiency and clean energy projects that provide bill relief. (LADWP)

Comment:

However, SMUD does not believe that there should be an explicit prohibition for POU's from returning allowance “proceeds” (the revenue from the sale of the allowances provided) in a volumetric fashion to ratepayers. ARB has stated that they do not intend to monitor or regulate POU rate structures or proceedings, nor do they intend to direct the CPUC's ratemaking authority on this issue. SMUD suggests that ARB should not establish an explicit prohibition that it does not have the authority to enforce, as that will likely just elicit market confusion.

At the very least, here, clarification is in order. POU's that consign allowances to auction are allowed to use the proceeds from those sales to purchase allowances at auction or on the secondary market, and are also allowed to simply retire those allowances to cover their compliance obligation. The ARB should clarify that such retirement does not constitute “Returning allocated allowance auction proceeds in a volumetric manner...” and is not prohibited by Sections 95982(d)(3) and (5). (SMUD)

Response: The commenters request that POU's continue to be allowed to deposit allowances in their compliance accounts. The first commenter opposes a prohibition on volumetric return of allowance value but supports a prohibition on volumetric return of allowance *proceeds*, which are that part of allowance value which comes from selling allowances. The second commenter opposes both policies but requests clarification that the prohibition applies only to proceeds and not to allocated allowances purchased using allocated allowance auction proceeds and then retired for compliance.

The regulatory amendments include a prohibition on volumetric return of allowance proceeds. This means that no monetary value stemming from the sale of allocated allowances may be returned to customers in proportion to their

³⁹ 2016 1SOR at 41.

electricity usage/purchases for any period of time. This prohibition does not mean that allowance value must be returned to ratepayers. The regulatory amendments indicate that allocated allowance auction proceeds may be used to reduce GHG emissions (so long as they do not violate any other regulatory prohibitions on the use of allowance value).

This amendment results in more equitable treatment of allocated allowance value for EDUs and natural gas suppliers, which are already prohibited from returning allocated allowance value in a non-volumetric manner, and ensures consistency in subsequent Cap-and-Trade Program impacts for electricity and natural gas customers. Finally, the Cap-and-Trade Regulation still allows for POU and co-ops to request that ARB allocate allowances directly to their compliance accounts.

B-1.23. Comment:

SMUD also suggests that the ARB consider a change to how allowances consigned to auction that remain unsold are handled. Currently, these consigned allowances remain in the auction pool for sale at the next auction. SMUD suggests that ARB should allow the consigning entities to instead place unsold allowances directly into their compliance accounts. This change will address a problem faced by entities that are required to consign their allowances (IOUs) or that have chosen to do so (POUs, in some cases) when those allowances remain unsold for multiple auctions. The problem is that these entities continue to face compliance costs, but are delayed indefinitely in getting the auction revenue intended to offset those compliance costs. (SMUD)

Response: The commenter requests that consigned allowances, if they remain unsold after an auction, be placed into their owners' compliance accounts. ARB staff proposed targeted amendments to these provisions, and no changes were proposed to the provisions that specify how consigned allowances are treated when they are unsold at auction. As such, the requested change is outside the scope of the rulemaking.

B-1.24. Multiple Comments:

MRR and COI fee compliance costs

We also support staff's proposal to explicitly prohibit EDUs and natural gas suppliers from using allowance value to pay for the costs of complying with the Mandatory Reporting Regulation or the Cost of Implementation Fee Regulation. Paying for the administrative costs associated with those regulations is clearly not consistent with the intended uses of allowance value and should be prohibited. (NRDC)

Comment:

SMUD supports including the prohibition of the use of allowance value to cover basic program costs (MRR, COI fees, etc.), in addition to the current prohibition of use to

cover obligations from sales into the CAISO, as seen in the Proposed Amendments. (SMUD)

Response: Thank you for the support.

B-1.25. Comment:

Customer outreach and education

Finally, we propose ARB add a requirement that all EDUs and natural gas suppliers develop and implement a customer outreach plan to maximize public awareness and understanding of the use of allowance value. This would mirror the requirement already in statute for the electric IOUs, but which is currently absent for the electric POUs and natural gas suppliers.⁴⁰ Based on initial surveys following the April 2014 issuance of the first climate credits on IOU household bills, less than half of customers were even aware they received a credit, and of those, three in four were unaware why they received it.⁴¹ While the state has since embarked on a statewide education campaign as part of Energy Upgrade California, clearly more effective customer outreach will be required to increase awareness and understanding of California's climate credits.

Proposed Modification to § 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers

(d)(3) Auction proceeds and allowance value obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. Allocated allowance auction proceeds may be used to reduce greenhouse gas emissions or returned to ratepayers. Any allocated allowance auction proceeds returned to ratepayers must be returned in a non-volumetric manner *and supported by a customer outreach plan for purposes of obtaining the maximum feasible public awareness of the crediting of auctions proceeds.*

(e)(3) How the electrical distribution utility promoted customer awareness and understanding of the disposition of any allocated allowance auction proceeds which were spent during the previous calendar year. (NRDC)

Response: The commenter requests that ARB require EDUs to conduct customer outreach to obtain the maximum feasible public awareness of the use of allocated allowance auction proceeds and report on this program as part of their use of allowance value reports. They make the same request for natural gas suppliers, which is addressed in response to comment B-2.9. ARB declines

⁴⁰ Pub. Util. Code sec 748.5(b) "Not later than January 1, 2013, the commission shall require the adoption and implementation of a customer outreach plan for each electrical corporation, including, but not limited to, such measures as notices in bills and through media outlets, for purposes of obtaining the maximum feasible public awareness of the crediting of greenhouse gas allowance revenues."

⁴¹ Opinion Dynamics, "Final Climate Credit Assessment," September 2014, available at: http://www.calmac.org/publications/ME%26O_Climate_Credit_Assessment.pdf

to make this change. While ARB supports the type of program contemplated by this requirement, staff does not see the need to require it at this time, notably because the Cap-and-Trade Regulation requires that all EDUs and natural gas suppliers annually report on the use of their allocated allowance value, and ARB publishes reports on those uses of value. Further, while some utilities are large and able to implement such a program efficiently, other utilities are small and may not be able to administer an outreach program comparable to that run by a large utility.

B-1.26. Comment:

Ten year deadline

We support staff's proposal to impose a deadline by which EDUs and natural gas suppliers must use allocated allowance value. Under the allocation framework for the electric and natural gas sectors, utilities receive allowance value for the exclusive benefit of their customers. If that value is not being timely invested in emissions reductions projects or returned to customers to mitigate cost impacts, it is not being used for its intended purpose. Staff's initial proposal of a ten year deadline, however, is too lenient and runs the risk of merely perpetuating the status quo. We propose instead a three year deadline, which still affords a measure of flexibility to accommodate planning and implementation needs but will better ensure allowance value (and its associated benefits) is not simply languishing in utility subaccounts.

Proposed Modification to § 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers

(d)(6) Deadline for Use of Allocated Allowance Value. The proceeds received from the sale of allowances allocated to an EDU must be spent by December 31 of the year *three ten* years after the vintage year of the allowances. To be spent, the proceeds must not remain in any account owned or controlled by the *EDU natural gas supplier* or its corporate associates. If the proceeds have not been spent within *three ten* years, they must be returned to ratepayers in a non-volumetric manner by December 31 of the year *four eleven* years after the vintage year of the allowances. (NRDC)

Response: The commenter requests the deadline for EDUs to use their allowance value be three years after they receive it rather than ten years, as newly required by the regulatory amendments. They make the same request for natural gas suppliers, as seen in comment B-2.8. Some EDUs may accumulate funds over several years and then use them to fund larger projects. Shortening the deadline to three years would prohibit use of this value for larger projects that may reap greater GHG emissions reductions, and therefore staff declines to make the proposed change. The purpose of the deadline is to ensure that the funds do not go unused indefinitely and to set a time period not longer than that in which ARB and the EDUs can reasonably keep records of the source and use of such proceeds.

B-1.27. Comment: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. (PG&E)

Response: Staff agrees with the commenter’s interpretation that allowance proceeds may be used for activities that result in long-term GHG reductions and benefit ratepayers. Transportation electrification may often, but does not necessarily, meet this requirement. Staff is available to discuss with stakeholders regarding which specific activities will result in GHG reductions.

*POU Consignment of Allocation Allowances***B-1.28. Comment:**POU Use of Allowances for Compliance

LADWP strongly supports ARB's proposal to continue to permit POUs to directly use allocated allowances for the post-2020 compliance period. Unlike IOUs, POUs operate for the exclusive benefit of their retail ratepayers and own and operate their generation assets on behalf of their retail ratepayers. POU-owned generation also is generally used only to serve POU ratepayers as part of a vertically integrated electric utility system. Unlike IOUs, POUs do not have subsidiaries that can profit from selling power on the market from their merchant generators. Thus, not-for-profit POUs have no incentive to use allowance allocations to artificially lower the price of the power from their owned resources in order to increase market share. Rather, they have a legal obligation to serve their communities and customers by providing reliable and clean electricity at the most affordable cost. Therefore, the concerns that led to ARB's 2010 decision to require IOUs to consign allowances to auction continue not to apply to POUs.⁴² (LADWP)

⁴² See ARB, Staff Report: Initial Statement of Reasons at IX-62 (Oct. 28, 2010), <https://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf> [hereafter "2010 ISOR"] ("Rationale for Section 95892(c). Monetization of allowances through auction is intended to ensure that the amount of value given to distribution utilities is transparent to the public, and that this value is used on behalf of electricity ratepayers. This practice will also ensure that freely allocated allowances to a distribution utility will not impact competition in the electricity generation market (where utilities compete with merchant power producers)."); *Id.* at 11-32 ("By requiring IOUs to put their allowances up for auction, the regulation maintains the current competitiveness of the deregulated California electricity market. In this way, utility-owned generation and independent generation have equal access to allowances."); ARB, Final Statement of Reasons at 342 (Oct. 2011), <https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf> [hereafter "2010 FSOR"] ("In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive

Response: The commenter expresses support for the proposed amendments, as they do not currently amend the consignment requirements for POUs. As such, no further response is required. Notwithstanding this, and as mentioned in the Second Notice of Public Availability of Modified Text, staff anticipates proposing changes in a future rulemaking to require POUs to consign their allowances like IOUs and return the value to industrial, small business, and/or residential ratepayers.

B-1.29. Comment:

Publicly-Owned Utility (POU) Consignment

While acknowledging the importance of prohibiting the volumetric return of allowance value, staff proposes to continue to afford POUs the option – unlike the IOUs – of turning in freely allocated allowances directly for compliance. That in turn operates as an implicit volumetric return by preventing retail electricity rates from reflecting the full price of carbon. And as ARB’s 2013 summary report on EDU allowance value reveals, that is what is happening with 84% of the allowances allocated to the POUs.⁴³

Staff has explicitly acknowledged the importance of consignment in the context of allocation to natural gas suppliers, noting (correctly) that it “incentivizes GHG reductions and creates equity between below- and above-threshold facilities” and that “full price pass-through will more closely align NG supplier allocation with EDU allocation.”⁴⁴ Yet this rationale is mystifyingly absent as applied to the POUs. At the March 29 workshop, staff attempted to distinguish the disparate consignment requirements for IOUs and POUs on the grounds that most POUs own and operate their own generation, and would accordingly be buying back a significant portion of the allowances consigned to auction (as they hold the compliance obligation). Of course, that is exactly the same situation as California’s natural gas suppliers, and in that context the rule still requires consignment – and indeed staff has indicated they intend to *accelerate* the consignment schedule for gas suppliers in a future 15-day rulemaking package.

The POU option also penalizes more efficient users relative to a scenario where, like the IOUs, the full range of allowance value is returned to customers independent of usage. That outcome is regressive, as on average higher income customers tend to consume more electricity. As new research demonstrates, the combination of consignment and Climate Credits provides *net financial benefits* for low-income

to make cost-effective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process.”).

⁴³ “Summary of Vintage 2013 Electrical Distribution Utility Allocated Allowance Value Reports,” at: <http://www.arb.ca.gov/cc/capandtrade/allowanceallocation/edu-v2013-allowance-value-report.pdf> (figure 2, p.7).

⁴⁴ http://www.arb.ca.gov/cc/capandtrade/meetings/20160329/caps_allocation_032916.pdf (slide 26).

households of the IOUs.⁴⁵ By proposing to continue the POU option, ARB is foreclosing the same opportunity for low-income households in POU service territories.

Accordingly, to truly align with the EDU allocation (not just the IOU allocation), we propose staff phase-in a consignment obligation for POUs alongside gas suppliers, with full consignment achieved by the start of the compliance period staff proposes for 2025-2027.⁴⁶

Proposed POU Consignment Schedule

Year	2021	2022	2023	2024	2025
Percent Consigned	20	40	60	80	100

At a minimum, the onus is on staff to justify disparate treatment for the POUs when for all other sectors ARB has recognized clearly the importance of consignment to preserve the carbon price in both wholesale and retail energy prices and encourage GHG reductions, reward more efficient users, maintain equity across sectors that compete for the same end uses, and increase liquidity in the market. (NRDC)

Response: The commenter requests that POUs be required to consign a portion of their allowances, with the percentage increasing over time. As indicated in the ISOR of this rulemaking, the Proposed Amendments to sections 95892(b)(2) and (3) were intended solely to remove a phrase (“or the first business day thereafter”) that is already covered by general statutory law in the California Health and Safety Code. These provisions were not modified with the intention of adding in another date for POUs to inform ARB of their consignment decisions. As such, the comment is outside the scope of the rulemaking and ARB declines to make the requested change. However, staff has indicated in the notice to the second 15-day changes to the regulation that it is contemplating proposing changes to the consignment requirement for POUs in a future rulemaking.

B-1.30. Comment:

The ARB Should Not Amend The Existing Provisions That Provide Publicly Owned Utilities With the Option To Place Freely Allocated Allowances Into Their Compliance Account Or Consign The Allowances.

The POU option to consign allowances or place them in the compliance account is an important element of the Cap-and-Trade Regulation and should be retained for at least three reasons. First, because POUs are typically vertically integrated, POUs should have the flexibility to have more control over the compliance of their utility owned

⁴⁵ UCLA Luskin Center, “Protecting the Most Vulnerable: A Financial Analysis of Cap-and-Trade’s Impact on Households in Disadvantaged Communities Across California,” at <http://innovation.luskin.ucla.edu/sites/default/files/FINAL%20CAP%20AND%20TRADE%20REPORT.pdf>

⁴⁶ <http://www.arb.ca.gov/cc/capandtrade/meetings/022416/arb.cpp.feb2016.pdf> (at 4).

resources. Requiring POUs to purchase 100% of their allowances would increase the exposure of the POUs ratepayer owners to fluctuations in the Cap-and-Trade market in addition to the market exposure many POUs already have, being vertically integrated. Second, the pool of allowances the POUs would offer in consignment would not make a significant contribution to market liquidity. Third, the IOUs do not have this option in part because of concerns that merchant generation must be able to fairly compete with utility owned generation and allowing the IOUs the same option as POUs would create a competitive disadvantage for merchant generators. Since most POUs rarely if ever compete with merchant generators, there is no need to require POUs to consign 100% of their freely allocated allowances. While this issue was not addressed in the Proposed Amendments, TID takes this opportunity to make clear that it would strongly oppose any such proposal. Furthermore, TID would support allowing POUs more flexibility in managing allowances by removing the once-for-all and one-time-only annual requirements that POUs are currently under. Such changes implemented carefully we believe could increase positively basic market characteristics. For example, if POUs could choose which individual auctions to participate in nearer in time, they could withhold allowances based on market conditions and reduce oversupply and carry-over of volumes. (TURLOCKID)

Response: The commenter requests that POUs continue to not have a consignment requirement. See response to 45-day comment B-1.28.

B-1.31. Multiple Comments:

Section 95892(b)(2) and (3) addresses the designation of allowances for consignment for POUs. Currently, the POUs designate the allowances that will be placed into the auction on September 1 for the following calendar year. In order to improve market efficiency, this section should be amended so that allowance designations are made two times per year, in September and March. This bifurcated allocation would facilitate smoother market operations by allowing sellers to respond to market price signals, which would be particularly useful for volatile years such as this one. (NCPA)

Comment:

ARB should increase flexibility to consignment sellers so they can respond to market signals and do not have to make as many "once-for-all" and one-time decisions about market participation.⁴⁷

a) This would contribute to the smooth functioning of the market by allowing sellers to respond to market price signals, changes in their portfolios and auction results. This would be particularly useful for volatile years such as this one where very few predicted

⁴⁷ For example, in October each year, each POU must decide once and irreversibly how many allowances will be offered at market in the following year, and the commitment of volumes for each auction must be made months in advance as well.

the crash in prices and auction volumes last year when consignment decisions were required.

b) Consignment decision elections 60 days prior to each auction or at the very least twice a year in October and April would balance the slight increase in administrative burden with additional flexibility for consignment entities. (CMCA)

Response: The commenters seek changes to IOU and POU consignment to increase flexibility in decisions regarding whether and when to consign allowances to auction. ARB staff notes that the amendments proposed in this rulemaking would not alter the existing timing requirements for IOU consignment deadlines or the existing flexibility POU's have to decide whether to consign or not. As indicated in the ISOR of this rulemaking, the Proposed Amendments to sections 95892(b)(2) and (3) were intended solely to remove a phrase ("or the first business day thereafter") that is already covered by general statutory law in the California Health and Safety Code. These provisions were not modified with the intention of adding in another date for POU's to inform ARB of their consignment decisions. As such, the comment is outside the scope of the rulemaking and ARB declines to make the requested change.

B-1.32. Comment:

LADWP supports and appreciates ARB's proposal to remove the obligation that POU's report on the number of allocated allowances that the POU has moved to its compliance accounts.⁴⁸ As the proposal states, this is information that ARB already has and reporting it presents an unnecessary burden. (LADWP)

Response: Thank you for the support.

Miscellaneous

B-1.33. Multiple Comments:

On the issue of allowance allocation, PG&E strongly supports continued allocation for the benefit of Californian utility customers, and staff's proposed customer cost burden approach. It's a great start. (PG&E3)

Comment:

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

⁴⁸ 2016 ISOR at 41.

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. (PG&E)

Comment:

LADWP supports ARB's proposal to continue to allocate a substantial portion of allowances in the post-2020 compliance period to electric distribution utilities (EDUs). Doing so has been an important mechanism for mitigating cost impacts of the Capand-Trade Regulation to California ratepayers. It has also fulfilled ARB's goal to "provide further incentives to the distribution utilities to meet or exceed the emissions reductions they expect to achieve through implementation of [complementary state] policies."⁴⁹ (LADWP)

Comment:

SMUD supports the basic EDU allocation starting point in 2021, based on the current 2020 allowance allocation, and modified by a one-time "true-up" of cost burden or compliance need to reflect changed circumstances and by the 2021 cap factor...

SMUD generally supports the basic allocation methodology for 2022 through 2026, in which the 2021 allocation is reduced to reflect the declining cap and the ending of specific high-emitting contracts. (SMUD)

Comment:

What I would like to use my time to say is that I'm going to go out on a limb and guarantee you that you will see direct emission reductions at in-state electric generating units by 2020. I can say that because I'll be retired or fired by then, so you won't be able to call me on that.

But here's my rationale. The period of the study that we've just looked at is simply too short and too unusual to make long-term conclusions of. It's only a few years. We had a huge drought, which increased emissions from the electricity sector. We had an unplanned loss of a large zero emitting resource, which increased emissions from the electricity sector. And we had a period where one of the direct measures that we are also subject to are -- has -- that we haven't as the industry, the RPS, was essentially at 20 requirement through the -- that entire period.

We'll have to be at 33 percent by 2020, and 50 percent by 2030. We have increasing energy efficiency requirements, which are -- our load is already decreasing and it's going to decrease more. We simply cannot continue making emissions from our power plants with those kind of direct requirements on us.

⁴⁹ ARB, Appendix 1 : Staff Proposal for 15-day Changes to Address Electricity Sector Allowance Allocation at 2 (Dec. 16, 2010), <https://www.arb.ca.gov/regact/2010/capandtrade10/res1042app1.pdf> [hereafter "Appendix 1"] .

The cap and trade provides actually a price which allows us to say, okay, rather than emitting, can we sell this asset? Can we put that into the market? And SMUD has done that and used some of the proceeds to fund electric vehicle fast-charges in our service territory, to fund deep energy efficiency retrofits for our low-income customers and disadvantaged communities.

You don't want to cut off that source of funds for us or for the State. So support for the cap and trade, and support for utility allocations, particularly to support the electrification transformation that we're all going to see. (SMUD2)

Comment:

We support continued allocation of allowances to the EDU to cover the cost burden of the program, and for the benefit of their electric customers. (NCPA2)

Response: Thank you for the support.

B-1.34. Multiple Comments:

LADWP requests that ARB provide more clarity regarding the specific methodology that will be used to determine such allocations. While it is LADWP's understanding that ARB intends to use a single methodology for allocating allowances for the entire post-2020 period, ARB's August 2 proposal is unclear on this point. The proposal's language that "staff may propose a methodology" has left an impression in the proposal that ARB is developing a separate method for allocating allowances during the 2027-2030 period. LADWP urges ARB to adopt the same cost-based allowance allocation methodology for the entire 10-year period to ensure consistency, provide greater regulatory certainty, and minimize administrative complexity. (LADWP)

Comment:

Though the regulation does not propose a post-2020 methodology, it does contain a partial allocation table that runs through 2026. SCPPA would recommend that, for whichever methodology is used, allocations for the full time frame up to 2030 be assigned. This would provide additional utility certainty and reduce the workload associated with revisiting this issue midway through the program's next phase. (SCPPA)

Response: The commenters request that ARB use a consistent allowance allocation methodology for EDUs for 2021-2030. The final regulatory amendments include electrical distribution utility allowance allocations for 2021-2030. A consistent approach is used for all these years, utilizing forecasts for the years available, which vary by utility, and projecting for the remainder of the ten-year period based on these forecasts.

B-1.35. Comment:

Section 95892(b)(3). POU Allowance Distribution Form

Under Section 95892(b) (3), POU and electrical cooperatives receiving a direct allocation of allowances must inform ARB by completing a Publicly Owned Utility or Electricity Cooperative (Co-op) Account Allocation Distribution Form of the accounts in which the allocations are to be placed. This process requires the POU to complete the form, have an authorized person sign the form, then mail the original signed form to ARB. If the POU or electrical cooperative does not submit the distribution preference by September 1, ARB automatically places all directly allocated allowances for the following year into the entity's Limited Use Holding Account. This means that the POU or electrical cooperative would be required to consign its entire allowance allocation to auction. For a vertically integrated POU that uses its allowance allocations to cover its emissions associated with generating station operation, this means that the POU would have to consign all of its allowances to auction, and at the auctions also try to buy them back. LADWP believes that the consequences of not filling out the form by the deadline are administratively costly. As stated in previous comments, LADWP recommends that a POU allowance distribution preference form should remain valid until updated, rather than having to submit a new distribution preference form every year. (LADWP)

Response: The commenter requests that, if a POU or co-op fails to submit a form specifying how their allowances be allocated between their (or a closely associated entity's, as specified in the Regulation) compliance account and limited use holding account, ARB should allocate allowances to the utility based on their previous years' allocation between the two accounts, rather than allocating all of them to the limited use holding account, as is done under the current Regulation. As indicated in the ISOR of this rulemaking, the Proposed Amendments to sections 95892(b)(2) and (3) were intended solely to remove a phrase ("or the first business day thereafter") that is already covered by general statutory law in the California Health and Safety Code. As such, this comment is outside the scope of these regulatory amendments. Staff also notes that the Cap-and-Trade Regulation does not require the use of a specific form to inform us which allocated allowances, if any, they wish to have deposited into a compliance or limited use holding account; the form is provided for convenience only.

B-1.36. Comment:

[In their January 2010 letter to ARB, included as an attachment to their comments, the commenter states:] We view the Proposed Regulation program as complementary to the measures DWR has already initiated to reduce SWP GHG emissions. However, we are concerned that, as proposed, the program will create inequities and have unintended consequences.

ARB's consultants, the Economic and Allocation Advisory Committee (EAAC), estimate the value of the emission allowances at between \$2.5 billion to 7.5 billion in 2012.

EAAC expects those cost to increase to between \$7.5 billion and \$22 billion in 2020.⁵⁰ These estimates are based on an EAAC assumption that all emission allowances are auctioned. The SWC suggests instead that ARB provide free allowances to carbon emitters and auction only those allowances needed to fund "Additional Reductions Necessary to Achieve the Cap." This approach reduces to 34.4 MMTCO₂ of emission allowances auctioned in 2020 instead of 365 MMTCO₂ assumed by EAAC.⁵¹ Limiting the number of allowances auctioned will help avoid the significant inequities that will likely be imposed on the SWP customers by the Proposed Regulation. Alternatively, the proposal by the Joint Utilities may also help avoid inequities, if it is properly structured and allocates allowances to all covered entities having a surrender obligation for electricity used to serve electric and water customers.⁵² However even a modified Joint Utilities proposal will lead to unintended consequences because of the amount of dollars this program will collect and redistribute.

To underscore our concern regarding unintended consequences of the Proposed Regulation we refer ARB to the effort to redesign the California electricity markets. That effort was born of good intentions, involved the allocation of a scarce resource through an auction, and transferred significant dollars between participants. In 2000 and 2001, "California was rocked by energy shortages and skyrocketing electricity prices."⁵³ State and federal policy makers and regulators were ill-equipped to deal with manipulation of the poor market design. Our first lesson from that catastrophe is "policy makers must respect market forces."⁵⁴ The customers of the SWP continue to pay for the unintended consequences of the attempt to restructure the California electricity market. The SWC is disturbed to find minimal consideration in the tone or substance of the Proposed Regulation that ARB will apply the lessons learned from the California Electricity Crisis. (STATEWATER)

Response: Staff declines to make the requested change to distribute more allowances freely and only auction the number of allowances necessary to fund additional reductions necessary to achieve the cap. Instead, the Proposed Amendments continue the Cap-and-Trade Regulation's approach to distributing allowances for the same reasons as specified in the 2010 ISOR. ARB allocates allowances to emissions-intensive trade-exposed industrial entities to prevent leakage. Allocation to these entities during 2013-2020 is also for the purpose of transition assistance, since these are the earlier years of the Program. ARB

⁵⁰ Recommendations to the California Air Resources Board from the Economic and Allocation Advisory, Untitled Table 3, "Allocating Emissions Allowances Under California's Cap-and-Trade Program." http://climatechange.ca.gov/eeac_reports/2010-02-07_EAAC_Allocation_Report_Draft.pdf . (January 7, 2010)

⁵¹ California Air Resources Board. Table 2: Recommended Greenhouse Gas Reduction Measures, Climate Change Scoping Plan." <http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm> . (December 2008)

⁵² THE JOINT UTILITIES. Letter to EAAC. January 6, 2010.

⁵³ Susan P. Kennedy. "The Oh Decade: California's electricity crisis stung – but made us stronger." Special to The Sacramento Bee. January 1, 2010.

⁵⁴ Ibid.

allocates allowances to utilities, including EDUs, natural gas suppliers and public wholesale water agencies, as defined in the Regulation, to protect their ratepayers from Cap-and-Trade Program costs. If prices were to escalate, allowances are available at set prices through the Allowance Price Containment Reserve; the Proposed Amendments would collapse the current three tier structure into a single tier, as described in responses to 45-day comments H-4.6 and H-4.7. With respect to the commenter's concerns regarding market manipulation, the Cap-and-Trade Regulation includes many features such as purchase and holding limits, corporate disclosure requirements, and enforcement provisions that mitigate against manipulation and undue attempts to exercise market power. Finally, a significant numbers of allowances are auctioned by the State. Auctioning makes these allowances available to all bidders and enables price discovery. Auctioning is the default approach recommended by the Economic and Allocation Advisory Committee, and ARB did not propose changes in this rulemaking to move away from the mechanism of distributing allowances via the quarterly linked auctions. For all of these reasons, staff declines to make the requested changes.

B-1.37. Comment:

ARB staff has consistently noted in the informal rule development process that the post-2020 EDU allocations will be utility specific, and there will not be a sector-wide sub cap as was the case from 2013-2020. SCPPA recognizes that the details really matter in a bottom-up calculation approach. To be fair, the data used to determine each utility's individual allocation needs to be reviewed for accuracy and normalized to a consistent set of assumptions. In addition, the GHG emission factors used in the post-2020 allowance allocation calculation need to accurately reflect the specific generating resources, and reflect the updated (SAR4) Global Warming Potential factors that will take effect starting in 2021. (SCPPA)

Response: The commenter requests that post-2020 EDU allocations use consistent data and assumptions and SAR4 global warming potential factors. ARB used consistent data and assumptions for post-2020 EDU allocations insofar as data were available. ARB used SAR4 global warming potential factors when calculating EDU allocations, although they do not change the emission factors used for electricity because non-carbon dioxide emissions play such a small role in electricity generation emissions. Details of EDU allocation data sources and calculations are provided in the Post-2020 Electrical Distribution Utilities Allowance Allocation Spreadsheet⁵⁵ that was part of the Second Notice of Public Availability of Modified Text, and more narrative explanations of the first 15-day proposal, including global warming potentials as used in that proposal and the final calculations, are provided in Attachment C to that proposal.⁵⁶

⁵⁵ <https://www.arb.ca.gov/regact/2016/capandtrade16/attach10.xlsx>.

⁵⁶ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachc.pdf>.

B-2. Natural Gas Suppliers

Consignment Requirement

B-2.1. Multiple Comments:

Allowance Allocation

Consignment Requirements for the Natural Gas (NG) Sector:

EDF supports the staff proposal to increase the percentage of allowances NG suppliers are required to consign to auction. Some transition assistance was appropriate. However, increasing the consignment percentage for the NG sector will create more parity with electric utility sector and create a more even price signal across the cap-and-trade program... In the electricity sector, the climate credit provided by utilities to households is providing a progressive benefit that shields low-income customers from overall increased costs while preserving an incentive to implement like energy efficiency that will lower electricity use. Moving to 100% consignment without a volumetric return of value in the NG sector will have a similar effect. (EDF)

Comment:

Natural Gas Supplier Consignment

For all the reasons stated above and in previous comments,⁵⁷ we strongly support staff's proposal at the March 29 workshop to accelerate the consignment schedule for natural gas suppliers after 2020. With the current minimum consignment level at only 30%, most of the carbon price in retail gas rates is muted and the monetized allowance value that is proposed to be returned to IOU households in climate credits (~\$12-15, once a year) will not be enough to drive meaningful additional reductions or to substantially raise awareness. As staff notes, partial consignment also creates disparities with non-covered customers of natural gas suppliers that face a carbon cost that is only a fraction of the cost faced by covered entities.⁵⁸ We accordingly support requiring full consignment starting in 2021 in a subsequent 15-day rulemaking, which would resolve these inequities and incentivize more reductions. As staff previously identified, reductions in natural gas use in response to a price signal alone may be able to achieve more than half of the gas sector's emission reductions under the cap.⁵⁹ (NRDC)

Response: Staff concurs with the commenters regarding the value of full consignment. However, in the second 15-day regulatory change proposal, ARB opted to gradually increase consignment in order to avoid sudden rate increases.

⁵⁷ See e.g. "NRDC Comments on the July 18 Workshop on Proposed Amendments to the Cap-and-Trade Program" (August 2, 2013).

⁵⁸ ISOR at p.45.

⁵⁹ ARB, "Suppliers of Natural Gas: Background and Options," slide 14 (June 3, 2013), available at: http://www.arb.ca.gov/cc/capandtrade/meetings/060313/natural_gas_suppliers_workshop_presentation.pdf.

The Second Notice of Public Availability of Modified Text indicates that “staff continues to believe achieving full consignment is necessary to incentivize natural-gas related GHG reductions and achieve equity between covered and non-covered entities. Maintaining cap adjustment factors for natural gas suppliers is expected to incentivize GHG reductions, and the proposed modification continues to achieve full consignment, if on a longer time line.” As such, staff declines to make further changes based on the comment.

B-2.2. Comment:

Furthermore, EDF supports ARB continuing to disallow a volumetric return of allowance value to customers. (EDF)

Response: Natural gas suppliers are prohibited from returning allowance value to customers in a volumetric manner under the existing regulation. Changing that prohibition is outside the scope of this rulemaking.

B-2.3. Multiple Comments:

The GUG Opposes an Accelerated Allowance Consignment Schedule

The existing Cap-and-Trade Regulation sets forth a minimum consignment of natural gas suppliers’ allocation of allowances that began at 25% in 2015 and increases by 5% per year, so that full consignment will be achieved by 2030. Allowances not consigned to auction may be retired for a natural gas supplier’s compliance without the otherwise associated costs showing up in customer rates. This approach helps transition the cost of greenhouse gas-reduction (GHG) into natural gas rates so that no rate shock is experienced. The Initial Statement of Reasons (ISOR) supporting the Cap-and-Trade Amendments proposes to expedite the post-2020 consignment requirement for natural gas suppliers.⁶⁰ California’s natural gas utilities worked closely with ARB in the 2013 – 2014 timeframe to develop the current consignment requirements. ARB’s proposal to accelerate the rate of consignment does not address these documented reasons⁶¹ for a gradual transition, which are still valid today. The GUG urges ARB to continue with the consignment rate that was developed three years ago as the most effective way to continue to reduce GHG emissions with minimal impact to California businesses and customers. (JOINTGASUTILS)

⁶⁰ 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

⁶¹ 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

Comment:

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...

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.⁶² California's natural gas utilities and other stakeholders worked extensively with ARB in the 2013 – 2014 timeframe to derive the current consignment requirement.⁶³ 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.⁶⁴ ARB's proposal to accelerate the rate of consignment does not address these documented reasons⁶⁵ 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 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, 2016.⁶⁶ 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.⁶⁷

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

⁶² 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

⁶³ 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.

⁶⁴ 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

⁶⁵ 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

⁶⁶ 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.

⁶⁷ PG&E plans to share with the ARB the impact of increased consignment requirement on customer rates.

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.⁶⁸ 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.⁶⁹ 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 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 allowances⁷⁰. 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.

⁶⁸ 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>>

⁶⁹ 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.

⁷⁰ Sec. 95892(b) Transfer to Utility Accounts, Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

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

A third rationale alluded to in the ISOR⁷¹ 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. (PG&E)

Comment:

Secondly, ARB should maintain the current consignment requirement for natural gas. Staff has proposed and acceleration of the rate of consignment post-2020. PG&E opposes this acceleration for several reasons. Given historical trends and experience, PG&E believes that an increase carbon price signal for natural gas will not actually motivate changes in behavior. This type of mid-course change could instead increase uncertainty in customer rates and it suggests that ARB can make other significant changes without allowing for the time needed to adapt accordingly.

Staff also cites wanting to create a level playing field between gas and electricity. However, this fails to recognize the fundamental differences between the sectors and the ability of publicly owned utilities to choose their own consignment level. These differences will persist, regardless of full consignment, and so parity will not actually be achieved.

In addition, natural gas customers have not had as much time to adjust to carbon regulation as others. Therefore, the transition to a more sustainable natural gas sector needs to be more gradual. Unlike the electric renewable market, the renewable gas market is much less developed and offers far fewer options. Higher incentives, rather than higher carbon pricing will be more effective in promoting commercially-viable renewable natural gas. (PG&E2)

⁷¹ 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

Comment:

SDG&E urges ARB to maintain the current 5% annual increase in required allowance consignment levels for natural gas suppliers. The most recent Initial Statement of Reasons (ISOR) that accompanies the 2016 Proposed Amendments indicates that staff is "evaluating an acceleration of the natural gas supplier consignment requirement" for post-2020 program years.

Alternative consignment levels have already been evaluated. Less than three years ago, California's natural gas utilities and other stakeholders worked together with ARB staff to determine the appropriate consignment rate of allowance allocations under the Cap-and-Trade Regulation. This effort included extensive policy discussions resulting in ARB's decision of starting with a minimum 25% consignment in 2015 and gradually increasing the minimum by 5% per year to 50% in 2020 with the goal of 100% consignment by 2030 (see page 16 of the September 4, 2013 Initial Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms⁷² and page 66 of the May 2014 Final Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms⁷³). Any acceleration of consignment requirements overlooks the documented reasoning for a more gradual transition to a full price signal, an approach that remains sound today.

SDG&E believes it is imperative for ARB to consider cost impacts from the Cap-and-Trade regulation in light of all future customer bill impacts for both natural gas and electricity, and to take into account the totality of bill increases that natural gas customers will be facing, especially low income households and small businesses.

SDG&E Recommendation: The Board should continue the 5% annual increase of NG Supplier utility consignment levels. (SDGE)

Comment:

Support Current Consignment Level Increases of 5% per year -The most recent Initial Statement of Reasons (ISOR) that accompanies the 2016 Proposed Amendments indicates that staff is "evaluating an acceleration of the natural gas supplier consignment requirement" for post-2020 program years. SoCalGas urges ARB to maintain the current 5% annual increase in required allowance consignment levels for natural gas suppliers.

Alternative consignment levels have already been evaluated. Less than three years ago, California's natural gas utilities and other stakeholders worked together with ARB staff to determine the appropriate consignment rate of allowance allocations under the Cap-and-Trade Regulation. This effort included extensive policy discussions resulting in ARB's decision of starting with a minimum 25% consignment in 2015 and gradually

⁷² <http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf>

⁷³ <http://www.arb.ca.gov/regact/2013/capandtrade13/ctfsor.pdf>

increasing the minimum by 5% per year to 50% in 2020 with the goal of 100% consignment by 2030 (see page 16 of the September 4, 2013 Initial Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms⁷⁴ and page 66 of the May 2014 Final Statement of Reasons-Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms⁷⁵). A change in course creates unacceptable uncertainty for the regulated business community. Businesses depend on firm decisions especially those that are agreed upon to extend over time; regulators should take these decisions seriously and alter them only when merited by substantial new evidence and public debate.

Further, any acceleration of consignment requirements overlooks the documented reasoning for a more gradual transition to a full price signal and is simply unsupported by any new information presented by staff. The original consignment level is an approach that remains sound today. The following points outline reasons why a continuation of 5% annual consignment increase is the most judicious approach:

1. ARB staff raised the concern of inequity between "covered" and "non-covered" electric generation customers as a reason for accelerating full consignment in the 2016 Proposed Amended ISOR Report (2016 ISOR). The 2016 ISOR states that "non-covered customers of natural gas suppliers are facing a carbon cost that is a fraction of the cost faced by covered entities, creating inequities among covered and non-covered entities." This argument is based on a false premise that all non-covered electric generating customers are in direct competition with the covered electric generating customers, and therefore, benefit from a competitive advantage resulting from lower cost fuel. In fact, only a small fraction of non-covered electric generating customers sell into the power market or enter into power agreements with utilities. An acceleration of consignment levels and a hastened cost pass-through will adversely impact ALL non-residential customers, including small businesses, non-profits and other vulnerable customer segments. Staff's hope to level the playing field between covered and non-covered customers will, in actuality, harm all non-residential customers in the effort to target a very small minority of electric generating customers. We feel this is an unbalanced approach. Exacerbating this impact is the fact that natural-gas rate structures typically assign a lower tariff to its largest consumers and vice versa, effectively nullifying any subsidy perceived between non-covered and covered electric generating customers.

2. The idea that full-price pass through more closely aligns the natural gas utilities with the electric distribution utilities' allocations fails to recognize the fundamental difference in the assessment of compliance obligations between natural gas utilities and electric distribution utilities. The compliance obligation is allocated directly to the gas utility based on retail sales, compared to point-of-generation or import in the electric sector.

⁷⁴ http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade_13isor.pdf

⁷⁵ <http://www.arb.ca.gov/regact/2013/capandtrade13/ctfsor.pdf>

While the State's natural gas suppliers are working to increase the number and volume of natural gas alternatives, supply is still too low to replace conventional natural gas at any significant scale. This necessitates a longer transition period to full rate impact for consumers.

3. The 2016 ISOR claimed that an accelerated consignment will "further the policy desire to limit the amount of fugitive methane emissions," but no evidence is provided to support this assertion. Fugitive emissions from natural gas utilities are emitted along the transmission and distribution systems and at storage facilities. These emission sources are both upstream from end-users and either outside the scope of the Cap-and-Trade Program or occur at facilities that are already directly covered by the Cap-and-Trade Program. Therefore, any perceived cost signal resulting from accelerated consignment would have a negligible impact on reducing emissions as rationalized in the 2016 ISOR. As previously stated in comments to ARB, SoCalGas is supportive of the Short- Lived Climate Pollutant (SLCP) Reduction Strategy's goals and objectives to reduce powerful climate forcing emission sources and putting organic waste to beneficial use as energy feedstocks and soil amendments. We remain supportive of working collaboratively with stakeholders and focusing on efforts that make real impacts on SLCP reductions. An accelerated consignment is not an effective measure to reduce SLCPs and will have an adverse economic impact on our vulnerable small business customers and other core customer segments.

4. Changes to current consignment requirements introduce regulatory uncertainty around procurement activities for all market participants by suggesting that ARB staff may suddenly modify allocation frameworks. The agreed levels of consignment for natural gas suppliers were designed to provide a balanced transition to a full carbon price-signal, mitigate market risk, and manage costs for California's natural gas customers. Altering the rate of consignment, particularly some of the more aggressive options proposed, fails to recognize the time needed to implement carbon reduction activities by both utilities and consumers.

SoCalGas believes it is imperative for ARB to consider cost impacts from the Cap- and-Trade regulation in light of all future customer bill impacts for both natural gas and electricity, and to take into account the totality of bill increases that natural gas customers will be facing, especially low income households and small businesses. This is particularly important given that customers cannot currently distinguish between price increases due to California's greenhouse gas programs and other costs such as those imposed by other regulatory changes. (SOCALGAS)

Response: The commenters request the current rate of increase in natural gas supplier consignment requirements, at 5 percent per year. ARB staff modified the originally proposed language in the second 15-day package to institute a 5 percent increase as requested by the commenters. See also response to 45-day comment B-2.1 for a description of the changes made in the second 15-day package that are consistent with the commenters' request for maintaining the 5 percent increase.

Some of these same commenters also request the “existing consignment requirement.” Whether they mean zero annual increase or an annual increase of 5 percent is unclear. Under the final regulatory amendments, the consignment requirement for natural gas suppliers will increase annually by 5 percent during the 2021-2030 period, which results in 100 percent consignment by 2030. Continuing to increase consignment requirements will incentivize reductions in natural gas use and thus GHG emissions, and eventually reaching full consignment will address equity concerns. Staff’s reasoning and analysis regarding the value of consignment is discussed further in Appendix D to the First 15-Day Notice.⁷⁶ An annual increase of 5 percent was selected to minimize the suddenness of the change.

Staff notes that regardless of the consignment rate, natural gas suppliers are required to use all allowance value for ratepayer benefit. Thus, higher consignment rates do not harm ratepayers as a whole. How revenues are distributed among ratepayers is the subject of CPUC proceeding R.14-03-003. ARB also notes that the Cap-and-Trade Regulation does not prohibit natural gas suppliers from preventing sudden rate increases by introducing GHG costs into rates gradually, as long as allowance value is not returned volumetrically.

Some comments mentioned that EDUs that are POUs or co-ops have no consignment requirement and this contributes to the inequity among consignment requirements which ARB is concerned about. See response to 45-day comment B-1.28 regarding staff’s consideration of proposing a consignment requirement for all EDUs in a future rulemaking.

B-2.4. Comment:

We are also very concerned about increasing the consignments and/or reducing the allowances. Staff has been clear with us that they think one of the impacts of that will be to increase investment in renewable natural gas. We don't believe that's the case.

And, in fact, we think there are much better ways to increase -- more effective ways to increase investment in renewable natural gas, and that conversation is ongoing with staff.

And then we also are very concerned, as Fariya spoke on PG&E's behalf, we [are] concerned about the potential impacts on our ratepayers as well. One of the goals that we believe we've had with ARB staff for some time now is a gradual increase in rates for ratepayers. And that's what we, as utilities, are trying to achieve in this environment. (SOCALGAS2)

Response: The commenter raises multiple issues. Increased consignment is discussed in responses to 45-day comments B-2.1 through B-2.3.

⁷⁶ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachd.pdf>.

As indicated in the 2011 Cap-and-Trade Regulation FSOR, transparent GHG price signals for fuel consumers help achieve emissions reductions in this sector. ARB anticipates that increasing consignment and the eventual outcome of California Public Utilities Commission Proceeding R.14-03-003 will increase the GHG price signal and thus encourage GHG abatement, and that this same proceeding will simultaneously increase customer climate credits that protect ratepayers from the increased price signal. Staff notes that none of the existing or proposed regulatory provisions prevent utilities from designing rate and credit systems that introduce these effects gradually. Staff shares the commenter's concern regarding customer impacts; however, staff believes that the relevant impacts to consider are the net impacts on customers after the use of allocated allowances to benefit ratepayers is taken into account.

Miscellaneous

B-2.5. Multiple Comments:

The GUG Supports Existing Cap Adjustment Factor for 2021-2030

The Cap-and-Trade Regulation Amendments do not address the cap adjustment factor for natural gas. The GUG believes that it is appropriate for ARB to apply the same cap adjustment factor for 2021-2030 that has been applied for 2015-2020. The lower cap adjustment factor for natural gas customers is appropriate for several reasons: first, natural gas customers came under the cap three years after other sectors and so have had less time to adjust to carbon regulation. Second, natural gas customers do not have the same suite of efficiency options available to them that electric customers enjoy, so that opportunities to reduce usage are considerably fewer. Finally, unlike the electric sector where there is a range of greenhouse gas (GHG)-free sources available for electric distribution utilities, natural gas suppliers currently have scant opportunity to procure renewable natural gas (RNG). Providing natural gas customers the less aggressive cap adjustment factor will allow natural gas suppliers time to ramp up development and procurement opportunities in a market that is just beginning to be developed. The cost of that market development will be reflected in retail gas rates, and a steeper decline in the cap adjustment factor would exacerbate those rate increases. (JOINTGASUTILS)

Comment:

Support a Continuation of Current Cap Adjustments Factors for Allowance Allocation-

While a change to the current allowance allocation adjustment factors was not proposed in the Proposed Amendments, SoCalGas strongly supports a continuation of current methods under the existing Cap-and-Trade Regulation. As intended, the direct allocations have successfully protected against rate impacts to utility ratepayers. A gradual step-down in emission caps coupled with the gradual increase (five percent per year) in consignment requirements is a prudent approach to safely introduce a price

signal while ensuring consignment revenue for distribution of Climate Credits to natural gas utility ratepayers. (SOCALGAS)

Comment:

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. (PG&E)

Comment:

My first point is about continuing allocation to natural gas suppliers, for ratepayer protection, and transition assistance. PG&E recommends that ARB continue to use the existing cap adjustment factor of approximately 2 percent for natural gas post-2020. (PG&E2)

Response: The commenters request that natural gas suppliers be subject to the 2013-2020 cap decline factor of about two percent annually rather than the 2021-2030 cap decline factor of about three and a half percent per year. ARB staff declines to make this change. Staff does not find the natural gas sector to be subject to unique conditions requiring a lower cap adjustment factor. As discussed in Appendix D to the First 15-Day Notice, there are many efficiency opportunities in this sector.⁷⁷ To apply a lower cap adjustment factor to the natural gas sector would, over time, lead to a decrease in allowances that are sent to auction, and would not provide equitable treatment of other sectors (e.g., industrial) that have a cap adjustment factor in line with the Program-wide cap.

B-2.6. Multiple Comments:

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.⁷⁸ (PG&E)

Comment:

The GUG Supports Allowance Allocation for the Benefit of Natural Gas Customers

Under the Cap-and-Trade Regulation, public and investor owned gas utilities, as "natural gas suppliers," are the point of compliance for natural gas customers falling

⁷⁷ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachd.pdf>.

⁷⁸ 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

below the 25,000 metric ton threshold for covered entities. These include residential, small commercial and industrial customers. The Cap-and-Trade Regulation Amendments propose continuing allowance allocation to natural gas suppliers for the benefit of these customers.

The GUG strongly supports the allocation methodology provided in the current regulation for natural gas, and the continuation of this approach to allocation in a post-2020 regime. (JOINTGASUTILS)

Response: The commenters express support for allocations to natural gas suppliers and using the existing allocation calculation methods. The regulatory amendments continue this approach for 2021-2030. Thank you for the support.

B-2.7. Multiple Comments:

The GUG Supports a Measured Transition to More Renewable Natural Gas

Unlike the renewables market for the electricity sector, the RNG industry is still in the early stages of development. There is considerable uncertainty on the availability of feedstock sources in the state and the country, as well as competition from other sectors (such as transportation) for those same sources. The GUG supports the objective indicated in the ISOR⁷⁹ of converting to a more sustainable natural gas sector, but urges caution against moving faster than development of the RNG industry can keep up with. Rather than increasing carbon costs through accelerated consignment, the GUG advocates for more policy incentives and funding. This includes more State funds (such as from the Greenhouse Gas Reduction Fund, and other state programs) to help defray the initial capitals costs of RNG projects, funding for research on conversion technologies, and development of large scale, stable RNG supplies at an affordable price. Policy incentives such as streamlined permitting to ease barriers are also needed to help the industry develop, and will be more effective in advancing RNG. (JOINTGASUTILS)

Comment:

Support Development of the Renewable Natural Gas Market – In contrast to the electricity sector, renewable natural gas (RNG) is in its early stages of development with limited access to feedstock sources. We urge ARB against artificially raising natural gas costs (such as through accelerated consignment or reduced direct allocation), at the expense of the consumer, in an attempt to encourage more RNG production and distribution. Rather than increasing carbon costs we feel a better return on investment will result from focusing on more policy incentives, capital cost assistance, and streamlining permitting and pipeline interconnection barriers. We support the objectives stated in the 2016 ISOR of transitioning to a more sustainable natural gas sector, and

⁷⁹ 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

believe targeted policies and incentives that help the RNG industry develop are more productive than broad-brush increases in the cost of natural gas. (SOCALGAS)

Response: The commenters request incentives and funding for renewable natural gas rather than an increase in natural gas supplier consignment. Renewable natural gas that meets the requirements of section 95852.1.1 of the Regulation is exempt from a compliance obligation and is thus incentivized by the Cap-and-Trade Program. Further incentivizing renewable natural gas is one among many benefits of consignment, which are discussed further in the response to 45-day comments B-2.3 above and in Appendix D of the ISOR.⁸⁰ More direct policy incentives or funding for renewable natural gas are outside the scope of this rulemaking and designating funding for specific GHG-reducing activities is outside the general range of topics addressed in the Cap-and-Trade Regulation.

B-2.8. Comment:

Proposed Modification to § 95893. Allocation to Natural Gas Suppliers for Protection of Natural Gas Ratepayers

(d)(6) Deadline for Use of Allocated Allowance Value. The proceeds received from the sale of allowances allocated to an EDU must be spent by December 31 of the year three ~~ten~~ years after the vintage year of the allowances. To be spent, the proceeds must not remain in any account owned or controlled by the natural gas supplier or its corporate associates. If the proceeds have not been spent within three ~~ten~~ years, they must be returned to ratepayers in a non-volumetric manner by December 31 of the year four ~~eleven~~ years after the vintage year of the allowances. (NRDC)

Response: The commenter requests the deadline for natural gas suppliers to use their allowance value be three years after they receive it rather than ten years, as newly required by the regulatory amendments. The commenter makes the same request for electrical distribution utilities, as seen in 45-day comment B-1.24. Some suppliers may accumulate funds over several years and then use them to fund larger projects. Shortening the deadline to three years would prohibit use of this value for larger projects that may reap greater GHG emissions reductions, and therefore staff declines to make the proposed change. The purpose of the deadline is to ensure that the funds do not go unused indefinitely and to set a time period not longer than that in which ARB and the suppliers can reasonably keep records of the source and use of such proceeds.

B-2.9. Comment:

Proposed Modification to § 95893. Allocation to Natural Gas Suppliers for Protection of Natural Gas Ratepayers

⁸⁰ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachd.pdf>.

(d)(3) Auction proceeds and allowance value obtained by a natural gas supplier shall be used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. Allocated allowance auction proceeds may be used to reduce greenhouse gas emissions or returned to ratepayers. Any ~~revenue~~ allocated allowance auction proceeds returned to ratepayers must be done in a non-volumetric manner and supported by a customer outreach plan for purposes of obtaining the maximum feasible public awareness of the crediting of auctions proceeds.

(e)(3) How the natural gas supplier promoted customer awareness and understanding of the disposition of any allocated allowance auction proceeds which were spent during the previous calendar year. (NRDC)

Response: The commenter requests that ARB require natural gas suppliers to conduct customer outreach to obtain the maximum feasible public awareness of the crediting of auction proceeds and report on this program as part of their use of allowance value reports. The commenter makes the same request for electrical distribution utilities, as seen in 45-day comment B-1.25. ARB declines to make this change. While ARB supports the type of program contemplated by this requirement, ARB does not see the need to require it at this time, notably because the Cap-and-Trade Regulation requires that all EDUs and natural gas suppliers annually report on the use of their allocated allowance value, and ARB publishes reports on those uses of value. Moreover, the use of most natural gas supplier allowance proceeds is subject to an open rulemaking (R.14-03-003) at the CPUC.

B-3. Legacy Contracts

B-3.1. Comment:

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

The sunset of allowance provisions for legacy contract generators appropriately incentivizes legacy contract generators to renegotiate their contracts with EDUs.... PG&E supports the sunset 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.⁸¹ ARB's removal of the

⁸¹ 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>

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. (PG&E)

Response: The commenter expresses support for ending legacy contract transition assistance to those legacy contract generators without industrial counterparties. Prior to these amendments, the regulation included provisions for legacy contract generators without industrial counterparties to receive transition assistance through vintage year 2017. In this rulemaking, those provisions were removed because they are moot after 2017. The current amendments do not change allocation for these generators, and therefore this comment is outside the scope of this rulemaking. Legacy contract generators *with* industrial counterparties continue to be eligible for legacy contract transition assistance.

B-3.2. Multiple Comments:

Panoche Energy Center (PEC) in Firebaugh, CA is a 400 MW natural gas peaking electric power plant that has historically been determined by the California Air Resources Board (CARB) to be a "Legacy Contract Generator" under the current Cap-and-Trade Regulation. This status recognizes that the PEC facility is unable to pass along GHG costs associated with the program under its contract with PG&E to the ultimate consumer of the electricity. These "stranded costs" are very significant and growing.

- CARB is currently amending the Cap-and-Trade Regulation to make modifications which take effect next year and also extend the program post 2020. In the immediate time preceding the amendment package release, staff presented at a public workshop a proposed solution for the issue facing PEC—to treat the facility the same way as other non-power plant Legacy Contract holders⁸². But the subsequently published amendments reversed course (without opportunity for public input) and now propose to completely eliminate "Legacy Contract" status and regulatory relief for PEC⁸³. The current draft amendments would leave the PEC facility, along with its bondholders, which include public pensions, completely exposed to the price of compliance. This is an inequitable situation not encountered by any other power plant inside or outside of California.
- The CARB Board is meeting on September 22 to hear the entire amendment package. Without an acknowledgement from the Board for staff to continue to address this issue CARB's current proposed amendments will strand PEC with

⁸² June 24, 2016 Workshop

https://www.arb.ca.gov/cc/capandtrade/meetings/062416/arb_and_caIso_staff_presentations_updated.pdf (slide 35)

⁸³ July 12, 2016 Released <https://www.arb.ca.gov/regact/2016/capandtrade16/appa.pdf>

the entire cost of the regulation--a total stranded liability exposure for 2015 will exceed \$5,000,000. Over the next 12 years PEC's stranded liability is set to be no less than approximately \$108,000,000, and likely will be much more.

- Under PEC's exclusive contract with PG&E signed in 2006 (before AB 32 was finalized, hence the term "legacy contract"), PEC operates the facility exclusively for PG&E. PG&E has full control over when the facility runs, and therefore also has control over the quantity of GHG and criteria (smog forming) emissions the facility emits.
- Critically, the fundamental "carbon price signal" associated with AB 32 is missing from the cost to PG&E's (and its ratepayers) for electricity from the facility. Without a price of carbon built into the dispatch orders, the facility has been operating far more than normal/design thus increasing: 1) costs for PG&E ratepayers, 2) increasing local air pollution, 3) increasing the use of scarce water resources, and 4) dramatically increasing the costs of operation, and 5) completely defeating the regulatory "price signal" intended to be sent to consumers.
- For the past three years, despite repeated attempts, PEC has not been able to negotiate a workable contract amendment with PG&E. The prior regulatory relief (set to be eliminated) and the current proposed amendments (failing to address PEC's issue), create zero burden or incentive for PG&E to address this situation, but their ratepayers, the citizens of the San Joaquin Valley, the facility bondholders, and the environment are all losers in this equation. There are no winners under the current proposal.
- If CARB were to revert to the earlier staff proposal, market forces would bring the operation of the facility into line with its design efficiency, it would release less local air pollution, it would use less water, it would cost less to operate and thus saving PG&E ratepayers on operational costs, and there would be a consistent policy price signal under AB 32.

(PANOCHE)

Comment:

The proposed amendments, however, also would have a significant negative impact on the environment and PEC's operations if adopted without further refinement. To avoid these impacts, and for the reasons described in this letter, ARB should not adopt the amendments as proposed on August 2, 2016, but instead should incorporate the June 24, 2016, staff workshop proposal constructed specifically to address the problem outlined below...

The tolling agreement was executed in March 2006 ("PPA"). PEC's "legacy contract" PPA does not include a mechanism to recover the cost of its GHG emissions. Under the PPA, PG&E controls when and how much the facility runs, and thus controls the

quantity of GHG and criteria pollutant (smog-forming) emissions the facility emits. The disconnect between the party who pays for the cost of carbon (PEC) and the party in control of the emissions (PG&E), has resulted in PEC's actual dispatch (and associated emissions) being much higher than its anticipated dispatch since the inception of the Cap and Trade Program.

Fundamentally, because PEC cannot pass the costs associated with its GHG emissions along to PG&E, those costs (the intended AB 32 "carbon price signal") are not included in PG&E's bids into CAISO for PEC's production ("dispatch price"). Without a price of carbon included in PEC's dispatch price, the facility has been operating far more than its intended design, consequently resulting in: (1) increasing local air pollution, (2) the complete undermining of the regulatory "price signal" intended to be sent to consumers, (3) increasing use of scarce water resources, (4) increasing costs for PG&E ratepayers, and (5) increasing costs of operation. Unless PG&E takes on the AB 32 compliance costs for the emissions created when it runs PEC's facility, this situation will continue unabated. It is understood that this is an unacceptable outcome.

Since the Cap and Trade Regulation's original adoption, PEC has continually sought in good faith to secure a just and reasonable contract amendment with its counterparty on terms consistent with other Public Utilities Commission approved Legacy Contract settlements entered into with other entities in PEC's position to ensure that the policies of ARB's Cap and Trade Regulation are uniformly implemented. PEC has repeatedly approached its counterparty to negotiate a resolution directly and through the offices of the Public Utilities Commission, ARB, private channels, and others, all to no avail. The structure of ARB's Legacy Contract Relief granted to PEC did not incentivize and may have dis-incentivized our counterparty from negotiating a settlement in good faith. Likewise, the proposed cessation of Legacy Contract relief would harm PEC and its bondholders, including public pension funds, and all other stakeholders (including PG&E ratepayers), except for PG&E who would continue to run PEC's facility without AB 32 compliance costs.

To address this situation, in the immediate time preceding the release of the amendment package, staff presented at a public workshop a workable solution that will treat the PEC facility the same as other non-power plant Legacy Contract holders.⁸⁴ But the subsequently published proposed amendments failed to include that staff's recommended solution (without opportunity for public input), and now propose to completely eliminate "Legacy Contract" status and regulatory relief for PEC. If adopted without change, the current draft amendments would leave the PEC facility completely exposed to the price of AB 32 compliance, stranding those costs with PEC, and would continue the ongoing environmental and economic consequences described above.

⁸⁴ Staff's presentation at the June 24, 2016, workshop (slide 35) <https://www.arb.ca.e:ov/cc/caoandtrade/meetin£s/06J416/arb> and caiso staff presentations updated. pdf, is included in Appendix F to the Initial Statement of Reasons <https://www.arb.ca.gov/ree:act/2016/capandtrade16/appf.pdf>.

The ARB Board meeting today provides an opportunity to correct this situation, and a way to move forward with a specifically tailored, holistic solution. PEC requests that the Board direct staff to amend the amendment language to include the June 24, 2016, staff workshop proposal in a future 15-day amendment package.

There are no legal impediments that prevent ARB from implementing PEC's request. Because the staff proposal was included in the Initial Statement of Reasons for the proposed amendments, modifying the proposed amendment to include staff's proposal in a future 15-day package complies with law. Likewise, the recent Court of Appeal decision in litigation between PEC and Panoche (currently pending before the California Supreme Court), and the earlier arbitration award, both acknowledge the limited contractual scope of that dispute, and explicitly state that nothing written in those decisions in any way limits ARB's power to resolve the issue of PEC's stranded costs in order that the PEC facility be run consistent with CARB policy to protect the environment and the public.

The prior regulatory relief (set to be eliminated) and the current proposed amendments (failing to address PEC's issue) provided no incentive for PG&E to address this situation, while the environment, the citizens of the San Joaquin Valley, PG&E's ratepayers, and PEC's bondholders are would be negatively affected. There are no winners under the current proposal, only losers.

PEC believes now is the time to finally address and resolve this lingering situation. We look forward to continuing to engage on this issue, and request that the Board include the June 24, 2016, staff workshop proposal in a future 15-day amendment package. (PANOCHE2)

Comment:

Panoche operates under the exclusive terms of a Power Purchase and Tolling Agreement, a PPA, with PG&E, which was executed in 2006. You can appreciate that in 2006, it would not have been possible to understand how the mechanics of AB 32 would play out when the Cap-and-Trade Regulation was finally adopted 5 years later in 2011.

As a result, Panoche currently has legacy contract status under the Cap-and-Trade Regulation. Like other legacy contracts, Panoche's PPA does not include a mechanism by which Panoche can recover AB 32 greenhouse gas compliance costs. Because PG&E is the scheduling coordinator for the facility, they control when and how frequently the facility runs.

The disconnect here is that the party in control of dispatching the facility, PG&E, is not who pays for the cost of carbon. That's Panoche. This creates a situation where Panoche is being bid into the market without a price for carbon, making it appear to be a lower cost, more efficient generation source than it actually is.

By implying that Panoche is more efficient than it actually is, PEC is running significantly more than it would if the carbon price signal were present. This in turn has caused an

avoidable increase in CO2 plant emissions and other criteria pollutants, increased water usage, avoidable increase in cost to ratepayers, and increased operational costs.

The best and preferred outcome is to resolve this without utility counterparty. We're continuing to work diligently on this front and are motivated to fix it there. Absent of that, or until the time occurs, we're seeking regulatory help.

Because the legacy contract provisions in the regulation are sunseting, until the issue is resolved in a contractual matter, we request that the Board recommend that the current regulatory amendments include language similar to what was proposed by staff in the public workshop in June of this year.

To that end, Panoche respectfully requests that the Board direct staff to include the June 24th, 2016 staff workshop proposal and a future 15-day amendment package. (PANOCHE3)

Response: The comments express opposition to ending legacy contract transition assistance to legacy contract generators without industrial counterparties. Prior to these amendments, the regulation included provisions for legacy contract generators without industrial counterparties to receive transition assistance through vintage year 2017. The allowances provided to legacy contract generators without industrial counterparties were taken from State-owned allowances that would otherwise be auctioned, with any resulting proceeds being deposited in the Greenhouse Gas Reduction Fund (GGRF). In this rulemaking, those provisions were removed because they are moot after 2017. The staff proposal referenced by the commenter was not proposed in the formal regulatory amendments package. Therefore, the requested changes are outside the scope of this rulemaking.

B-3.3. Comment:

As proposed on pages 222-223 of Appendix A – Section 95894, P&G is glad to see the modifications to the Legacy Contract section. In particular, we greatly appreciate the addition of the new 60 day renegotiation eligibility cut-off prior to the application deadline. (PROCTER&GAMBLE)

Response: Thank you for the support.

B-3.4. Comment:

Section 95894 should be further modified to provide the ARB with additional flexibility to achieve the policy goals of the legacy contract provisions. CARB should revise Section 95894 to provide the Executive Officer with discretion to provide a true-up allocation for the legacy contract counterparty when a Legacy Contract Generator is no longer eligible for Legacy Contract Status, or when an application is later deemed to have been approved in error.

As proposed, Section 95894 of the regulation does not have a mechanism with which ARB can transfer allowances between entities in the case of a dispute. For example, if a

party disputes a transfer of allowances through legacy contract after the legacy contract application deadline, there is no clear mechanism with which ARB can reclaim the transferred allowances disputed. This places ARB in a situation where they have little ability to act in the case of a legitimate dispute. The Executive Officer should have greater discretion and authority to implement the policy goals of Section 95894. (PROCTER&GAMBLE)

Response: The commenter requests that ARB revise section 95894 by creating provisions to increase ARB's discretion in resolving situations where a legacy contract applicant received transition assistance in error or received it appropriately but has ceased to be eligible for it. ARB declines to make the requested changes. The existing language in 95894 and elsewhere provides ARB with the necessary authority to address the situations described by the commenter.

If a legacy contract generator renegotiates its contract during a year for which it has received legacy contract transition assistance, ARB does not seek to recover those allowances from the generator. ARB encourages legacy contract generators to renegotiate their contracts and considers these allowances an incentive to do so. The generator would then be ineligible for receiving further legacy contract transition assistance.

If a legacy contract transition assistance application was deemed to have been approved because of incomplete or inaccurate information submitted by the legacy contract generator, ARB would require the generator to return the allowances to ARB or transfer them to their counterparty if ARB had subtracted them from their counterparty's allocation.

ARB has the authority under what is now section 95894(d) to request the information it deems necessary to identify errors or address disputes.

B-4. Public Wholesale Water Entities

B-4.1. Comment:

CMUA also supports allocating allowances to a public wholesale water agency in the post-2020 period using the same methodology used in the existing regulation. (CALMUNIUTILASSOC)

Response: The regulatory amendments continue allocation to public wholesale water agencies post-2020 using the methodology used in the previously existing regulation, as requested by the commenter. Thank you for the support.

B-4.2. Comment:

Under the current C&T regulation, Metropolitan, as a public wholesale water agency is provided an annual allocation of allowances to help meet its compliance obligation. In the C&T proposed amendments, ARB is proposing to retain this annual allowance allocation through 2020 and for future budget years after 2020. Metropolitan supports

ARB's retention of the current allocation both through 2020 and in future budget years, as ARB references in Sections 95871 and 95895 of the C&T proposed amendments...

In order to bring Colorado River water to Southern California, Metropolitan often imports energy into California exclusively to serve the wholesale electrical pumping requirements of the California River Aqueduct. This wholesale energy is not marketed or resold to other entities in California; it is used only by Metropolitan to bring water into Southern California, and the amount imported varies from year to year, depending on Metropolitan's pumping needs... ARB amended its regulations to allow public wholesale water agencies to receive an allowance allocation. Metropolitan has received this annual allocation since 2015, and looks forward to continuing allocation post 2020. Note that ARB will need to update the current definition of public wholesale water agencies to reflect the data years from 2020-2030, since the current definition refers to 2013-2020. (MWD)

Response: As the commenter indicates, the regulatory amendments continue allocation to public wholesale water agencies post-2020 using the methodology used in the previously-existing regulation. Thank you for the support.

The commenter also requests that ARB update the regulation's definition of a public wholesale water agency to include 2020-2030 in the years that such an agency must have a compliance obligation, rather than referring to 2013-2020. ARB has adopted this request as part of the first 15-day amendment package and updated the definition to refer to the years 2013-2030.

B-4.3. Comment:

A significant part of the SWP costs relate to water generated and purchased at wholesale for the ultimate purpose of pumping water to consumers across wide areas of the State.

Delivery of this water is vital to the health, welfare, and productivity of the State of California. Implementing AB 32, SB 350 and SB 32 measures is having a significant impact on the SWP customers. That is true even though the SWP relies on a power supply that is more than 60 percent carbon free. Thus, the SWC has a vested interest in the ongoing development of the Proposed Amendments.

In our communications with ARB we have pointed out the inequitable treatment of the SWP customers in comparison to others that are similarly situated. That inequity leads to the SWP customers being exposed to the risk of "skyrocketing prices" when the economy experiences robust growth. But even during periods of stagnant to moderate growth, the SWP customer's Cap-and-Trade cost burden has been significant. The Board directed the inequity be addressed in its Resolution 11-32. Chairman Nichols' 2012 letter set forth a temporary path to partial relief. However, questions about the future viability of the Cap-and-Trade program and evolving priorities of the Investment Plan show that is not a sustainable solution.

The SWC encourage the ARB to take this opportunity allocate emission allowances to the SWP in a fashion similar to the electric utilities. This will address the oversight that has led to the inequitable treatment of the SWP customers, mitigate significant costs and risk of skyrocketing prices and provide a sustainable path forward that is under the control of ARB.

[In their June 2011 letter to ARB, included as an attachment to their comments, the commenter states:] It was in response to our comments that Assistant Executive Officer Kevin Kennedy acknowledged to the Board that staff had overlooked cost impacts to the customers of the SWP. Mr. Kennedy gave assurances to the Board that he would investigate how the SWP customers could receive treatment similar to that being applied to the customers of the electric distribution customers in a discussion leading to the Board adopting the regulations.

Unfortunately, we are no closer to achieving that outcome nearly six months later. The SWP emission allowances continue to be allocated to the electric distributions utilities instead of to the water agencies. It is unlikely the Board or Mr. Kennedy intended that the water customers would subsidize the electric customers in this fashion. Furthermore, we do not believe it was the Board' s intent that the water customers enter this transition period being singularly exposed to the rate increases inherent to untested markets. It should be also noted that the price signals that are so vital to modifying the behavior of customers are lost to the water customers if this oversight continues.

During the course of the Board hearing Mr. Kennedy indicated to the Board and customers of the State Water Project that water customers could receive free allowances to mitigate price increases. It seems that this has been forgotten with Mr. Kennedy's departure.

[The commenter attached an August 2012 letter from ARB to the Metropolitan Water District of Southern California. In this letter, Mary Nichols expressed commitment to water efficiency investment using auction revenues.]

(STATEWATER)

Response: The commenter requests allowance allocation to the State Water Project “in a fashion similar to the electric utilities.” ARB declines this request.

Staff believes that it is important to capture the emissions associated with water distribution. As noted in the Final Statement of Reasons to the 2010 Regulation, there are opportunities for reductions in the emissions associated with this activity, and the emissions are not insignificant. Staff notes that the role of water distribution entities in the economic value chain between producers of electricity and end-use consumers of water services is most closely associated with electricity marketers (not electric utilities), and their treatment under the regulation is consistent. Staff believes that it would be inappropriate to provide direct allocations to the water distribution utilities for the benefit of end-use

customers, because they do not have a direct relationship that would facilitate the return of value in a way that would maintain the marginal incentive of end-use customers to reduce emissions. Further, the emissions associated with water distribution are included in the share of value returned to end-use customers through EDUs. When examining this issue in the 2010 rulemaking, staff performed an analysis of the distortion created by returning value through electric distribution utilities, as opposed to water distribution utilities, and found the effect to be insignificant. Staff continues to support this conclusion.

B-5. Industrial Allocation

Benchmarks

B-5.1. Comment:

New Product Lines from Covered Facilities

CARB staff should consider the development of criteria that would provide allowances for covered entities for the development of new products. Currently, covered facilities cannot receive credits for emissions from new product lines until a benchmark is developed by CARB. The new product line cannot be issued an energy-based benchmark if the product is produced on a site that is subject to a product-based benchmark. The lack of a benchmark that will allow for additional allowances stifles innovation.

CARB should develop criteria that will allow the issuance of an interim benchmark or energybased benchmark, pending the development of a final benchmark for the new production line. The interim benchmark could be subject to true-up to prevent windfalls.

Milk Powder Definitional Changes

The term “milk powder” used in the definitions of milk powder (high heat), milk powder (low heat) and milk powder (medium heat) is a broad term that includes the following:

- Skimmed milk powder (SMP) – skimmed milk powder obtained through standardization with lactose and dried; and
- Non-fat dried milk powder (NFDM) – non-fat, non-standardized dried milk powder. It is recommended that the term “milk powder” be included with the above definitions to provide additional clarity.

CARB proposes to remove the benchmark for “cream”, substituting “anhydrous milk fat processing” as the term for the same benchmark. The CARB definition of “anhydrous milk fat” does not include cream in the definition.

It is recommended that CARB modify the definition of “anhydrous milk fat” as follows:

“Anhydrous milk fat means fatty products, including cream, derived exclusively from milk and/or products obtained from milk by means of processes which result in almost total removal of water and nonfat solids.”

The recommended modified definition ensures that cream is included in the benchmark as defined by ARB.

- CLFP notes that the product benchmarks for milk powder (medium heat and high heat) and milk powder (low heat) are different. There is no explanation or rationale explaining the reason for the different benchmarks. CLFP would like to discuss with CARB staff the reason behind the different benchmarks.

(FOODPROCESSORS)

Response: The commenter request the addition of interim benchmarks for new products, clarification/modification of definitions of some dairy products, and clarification on milk powder benchmarks. When any covered facility or potentially covered facility would like ARB to consider developing a new product benchmark, they can notify ARB staff and we will work with any entities in that sector that produce the same product to determine if a new product benchmark is appropriate. Staff recognizes that entities may develop new product lines over time, and the Regulation includes a robust true-up mechanism with immediate usage of new benchmarks as soon as they are reported under MRR. Staff’s ability to work with industries to develop new product benchmarks for industries at risk of leakage has been shown in past rulemakings as well as the current rulemaking, the latter with the development of several new products, including boric acid equivalent, sulfuric acid regeneration, and several updated dairy benchmarks.

Proposed changes for “milk powder (low heat)” and “milk powder (high heat)” definitions do not specify fat contents. They can include milk powder made from non-fat milk, skim milk, and whole milk. These benchmarks were developed with the approval of milk processors both in the 2013 rulemaking and the current rulemaking. An explanation of why separate benchmarks are appropriate for low and medium/high heat milk powders can be found on page 10 of Appendix A: Product-based Benchmark Development (<https://www.arb.ca.gov/regact/2013/capandtrade13/2appabenchmarks.pdf>) to the second 15-Day regulatory change proposal for the 2013 rulemaking.

Staff does not propose to replace the existing benchmark for “cream” with “anhydrous milk fat processing.” Cream and anhydrous milk fat are considered separate products. The cream benchmark will be maintained through vintage 2018 allocation, after which time cream will be allocated to using the new “fluid milk product” benchmark. A new definition for anhydrous milk fat is added so staff can work with stakeholders to develop a benchmark at a later time, if determined appropriate and necessary.

B-5.2. Comment:

Staff has also proposed several changes to definitions for Dairy Product Manufacturing activities. Staff states there were issues with the original benchmark but no explanation regarding the problem is provided. Staff should provide an understanding on their thinking for NAICS code 31151, to help inform the dairy industry and this regulatory process.

We oppose the deletion of the definition for “dairy product solids for animal feed processing.” Staff states that they are eliminating this definition, as well as the benchmark, because the level of allowance allocation under the benchmark is negligible. Dairy product solids for animal feed processing are a byproduct from normal manufacturing. Because it is a byproduct it is difficult to predict when the benchmark may be utilized, but it is needed. We urge ARB to keep this benchmark...

Staff proposes to delete the “dairy product solids for animal feed processing” benchmark. We oppose the deletion of this benchmark. As stated before, dairy product solids for animal feed processing are a byproduct from normal manufacturing. Therefore, this benchmark needs to remain in the Regulation.

Recommendation: We urge ARB staff to work with the dairy industry to find a solution to maintain this benchmark. Simply deleting the benchmark is not the proper course of action. (AGCOUNCIL)

Response: The commenter opposes the proposed deletion of the benchmark for “dairy product solids for animal feed processing.” Staff worked extensively with covered entities that produce dairy product solids for animal feed processing, including an assessment of the magnitude of emissions associated with this product, the administrative burden to report production to ARB, and the fact that emissions associated with the production can still be included as part of total emissions covered by other dairy benchmarks. Together, staff and these covered entities came to the mutual decision that it was advisable to delete the dairy product solids for animal feed processing benchmark. As such, staff declines to make the requested change.

B-5.3. Multiple Comments:Section 95802 – Definitions

We appreciate staff working with covered entities in the Fruit and Vegetable Canning benchmark to amend definitions relating to tomato processing. These amendments help clarify covered activities that are performed under food manufacturing NAICS code 311421. (AGCOUNCIL)

Comment:

NTSS/TSS

CLFP welcomes the proposed changes to the TSS or NTSS as the methodology is consistent with industry practice and will result in a more accurate measurement of Tomato Soluble Solids. (FOODPROCESSORS)

Response: Thank you for the support.

B-5.4. Multiple Comments:

Section 95891 – Allocation for Industry Assistance

Table 9-1: Product-Based Emissions Efficiency Benchmarks (page 174) This table proposes changes to benchmarks for covered facilities.

Staff is proposing to eliminate the benchmark for tree nut manufacturing because emissions per unit of product are highly variable. In absence of a benchmark, staff is proposing that covered entities conducting this activity will receive allowance allocations under the energy-based methodology.

We oppose the deletion of this benchmark. All agricultural production is subject to weather changes, which will alter the emissions of processing plants. Additionally, many crops have alternating crop years, which means some harvest years are lighter than others. This will also impact the amount of processing and emissions that occur during the processing cycle. These events do not mean that the product-based benchmark is not needed. In fact, the benchmark is needed even more so that the potential variability in crop years is reflected in the regulation. Otherwise, it will further disadvantage the processor by moving it into a generic energy-based system. This change creates additional issues for covered entities performing this activity, as noted in our comments below under (c)(3) Energy-Based Allocation Calculation Methodology.

Recommendation: Reinstate the benchmark for tree nut manufacturing and refine the product-based benchmark to reflect updated data and efficiency trends. (AGCOUNCIL)

Comment:

1. Roasted Nuts and Peanut Butter Manufacturing (NAICS 311911) Should Remain Under the Product-Based Benchmarking Category

ARB has tentatively proposed to eliminate tree nut manufacturing from the product-based benchmarking category. Instead, manufacturers in this NAICS code will be subject to energy-based benchmarking. In the *Initial Statement of Reasons*, ARB is proposing to change the product-based benchmark for this category based on the following reasons (1) emissions in these sectors are highly variable making it challenging to accurately predict the energy required to roast nuts; and (2) there are no longer any covered entities conducting activities that fall within this category. We are opposed to the elimination of product-based benchmarking for tree nuts because ARB has failed to provide valid legal or factual rationale for doing so. Therefore, we request that the product-based benchmark for tree nuts be retained. If ARB needs additional

technical information to further refine the previously approved benchmarks, WPA is committed to providing ARB that information.

As a fundamental issue, it is inappropriate for ARB to completely eliminate the product-based benchmarks that WPA spent over a year developing in a collaboration with ARB, and that were adopted in 2014. Regulated entities need regulatory certainty. It is unfair for ARB to propose such a significant change to its approach a mere two years after it initially adopted the product-based benchmarks

A. WPA Will Be Back in the Cap-and-Trade Program for 2016

In terms of ARB's factual rationale, while it is true that there are no covered entities currently subject to the Cap-and-Trade Program utilizing the product-based benchmark for roasted nuts, the 2016 crop will put WPA back in the Cap-and-Trade Program. The pistachio crop, like many other agricultural commodities that are impacted by weather, is variable. Last year, the industry produced 275 M lbs, while this year the estimated volume is a record 750-800 M lbs. To date, Wpa has already processed 300 M lbs of pistachios at the same Lost Hills facility that was previously covered by the Cap-and-Trade Program. Greenhouse gas (GHG) emissions for nut processing facilities are closely correlated with pistachio and almond harvest volumes, which are directly influenced by climate, a factor outside of WPA's control. Due to extended drought conditions and other weather related issues, including insufficient chilling hours during the winter, 2013, 2014, and 2015 harvest volumes were down, and consequently GHG emissions at the WPA Lost Hills, facility stayed below the Cap-and-Trade Program applicability threshold. But, based on a record harvest for 2016, WPA will be back in the Program next year, so elimination on the basis that there are no longer covered entities is not factually justified.

B. Variability of Emissions and Moisture Content is Inherent in Nut Processing and Previously Acknowledged by ARB

With regard to the variability in emissions, like many other agricultural products, the climactic and soil condition under which pistachios and almonds are grown, largely influence the moisture content of these products. As the climate and soil conditions change year to year, the moisture content of the product changes variability of moisture content of the raw pistachios and almonds is an inherent characteristic of tree nuts, which has always existed. During the 2013 rulemaking process, ARB was provided with a great deal of information regarding the harvest production, storage, treatment processes, and fuel consumption related to the processing of pistachios and almonds, and this information was used by ARB to develop the appropriate product-based benchmarks for pistachios and almonds, respectively. The harvest methodology and the inherent variability of moisture content in WPA's raw pistachios and almonds did not change since the 2013 rulemaking. It is therefore neither appropriate nor fair for ARB to propose elimination of the 311911 NAICS code benchmarks because the water content of raw nuts varies year-to-year.

2. If Necessary, ARB should Refine the Product-Based Benchmark, Rather Than Eliminate It

ARB asserts that product-based benchmarking is the preferred approach in order to minimize leakage. However, ARB's proposal to eliminate product-based benchmarks for pistachio and almond products is inconsistent with that approach and the intent of AB 32. As such, we strongly recommend that ARB consider refining the product-based benchmarks for pistachios and almonds, as opposed to elimination of the category. Such an approach is similar to ARB's proposal with respect to calcium ammonium nitrate solution and nitric acid production (NAICS code 325311), where emissions are also highly variable. Wonderful recommends that ARB bear in mind the following when considering the product-based benchmark calculation for this category:

- The initial benchmarks were derived using 2010 and 2011 data. The product-based benchmarks should be updated using data years 2010-2015 because: (1) ARB has Mandatory Reporting Regulation data to ensure the rigorosity of the data quality (2010 through 2015 are verified); and (2) efficiency tends to improve over time, such that using these data years for nut products ensures that efficiency improvements are taken into account in an equitable manner.
- Because Wpa is the only covered entity under the Cap-and-Trade program, apply ARB's benchmark stringency with "90% of Average" or "Best-in-Class" value, using the 2010-2015 data from WPA.

If ARB requires additional information to further refine the product-based benchmark for roasted nuts, including developing refined benchmarks for each process, WPA would be happy to work with ARB staff to provide that information. (WONDERFUL)

Response: The commenter requests that staff maintain product-based benchmarks for the almond/pistachio sector under NAICS 311911. Staff was able to work with Wonderful Pistachios and Almonds to develop in the second 15-day amendment package product benchmarks for almond blanching, almond flavoring, almond pasteurization, pistachio flavoring, and pistachio hulling and drying. Staff believes these benchmarks more accurately represent emissions per unit product for the sector than the previous benchmarks contained in the Regulation. These benchmarks will be implemented starting with vintage 2019 allocation. The pre-existing nut benchmarks are reinstated for allocation through vintage 2018 allowances.

B-5.5. Comment:

Kimberly-Clark ("K-C") has actively engaged with staff for over three years as staff continued to maintain that there is a valid relationship between water absorbency of tissue products and greenhouse gas ("GHG") emissions as set forth in the current Regulation's benchmark for tissue manufacturing. K-C's consistent comments throughout these three years have shown that the current tissue benchmark with its

absorbency factor is inconsistent with ARB guidance, unreasonably burdensome, unfair, and without technical support. K-C therefore wholeheartedly welcomes the proposal to strike it from the Cap-and-Trade Regulation.

K-C continues to believe that ARB ought to adopt a tonnage-based benchmark in accordance with its guidance, as it originally did in 2011. However, while it is by no means perfect, ARB's proposed energy-based benchmark aligns with K-C's approach to reducing GHG emissions across all of its operations. K-C has set an absolute emissions cap and established reduction targets from this cap. K-C therefore supports replacing the current tissue benchmark with the proposed energy-based benchmark. K-C also calls upon ARB to make the benchmark retroactive or to otherwise address the undue costs borne by the elements of the regulated community as a result of the current benchmark. (KIMBERLY-CLARK)

Response: Thank you for the support.

B-5.6. Comment:

On Sections 95102 (b), 95118 (d), 95802, 95871, 95891 Regarding Future Amendments to Product Definition, Product Benchmarks, Industrial Assistance Factors and Associated Reporting Requirements for Nitric Acid and Calcium Ammonium Nitrate Solution Product Sectors.

In the above referenced sections of the proposed rule amendments, CARB staff outline their intentions to review and revise the regulatory definitions of nitric acid and calcium ammonium nitrate solutions, modify previously established industry sector benchmarks, propose new industrial assistance factors post 2020 and require changes to associated regulatory reporting at some point in the future. Any proposed changes to these regulations would be subject to a 15-day public comment period.

As owner/operator of one of a limited number of nitrogenous fertilizer facilities currently operating in the state of California, JR Simplot possesses inherent technical knowledge of the nitric acid and calcium ammonium nitrate manufacturing processes that would be essential to developing sound, science based regulatory changes to meet the needs of the MRR and Cap & Trade programs. JR Simplot respectfully requests the opportunity to meet with CARB staff to review and discuss any proposed changes to the regulatory requirements impacting the nitric acid and/or calcium ammonium nitrate industrial sectors well in advance of a public comment period. (SIMPLOT)

Response: Staff added new benchmarks for nitric acid production and calcium ammonium nitrate solution production in the first 15-day amendment proposal released December 21, 2016. Staff appreciates JR Simplot's effort and cooperation in assisting staff with the development of these new benchmarks

B-5.7. Multiple Comments:

(c)(3) Energy-Based Allocation Calculation Methodology (page 195)

Staff proposes to modify provisions related to when an entity receiving energy-based allocation does not perform a covered activity for part of a year because it has shut down or exited the program. When this occurs, the covered entity must return freely allocated allowances for that year to ARB in proportion to the fraction of time during the year that it was shut down.

Ag Council and AECA are concerned for any of our member companies that may receive an allowance allocation under the energy-based methodology in the future. In our analysis, our members could be subject to this “return of allowances” provision. Some of our members only operate part of the year or could easily drop below the program threshold in the off-season (and periodically for an entire year due to small crop size, or other issues), causing them to return a proportion of the allocations they receive. The process for returning allocations is unclear and increases uncertainty in this program.

Recommendation: ARB needs to make some accommodation for the seasonal nature of agriculture and the volatility our sector experiences from extreme weather and changes in water availability. These influences are out of our control and affect the volume of processed food in California.

If ARB is concerned with businesses that are no longer in the program selling free allowances, it could prohibit those types of sales without the requirement of the “return back” provision it currently proposes. (AGCOUNCIL)

Comment:

3. Covered Entities Should Not Be Required to Pay Back Allocation Allowances Immediately

ARB has proposed to modify provisions related to the return of allowances by entities that were allocated free allowances and subsequently did not incur a compliance obligation or applied to exit the Cap-and-Trade Program. We acknowledge that the proposed changes are set to take effect for budget year 2018 and forward, but believe this is a critical issue, especially for entities in the agricultural sector that have variance GHG emissions, and therefore could come in and out of the Cap-and-Trade Program.

We recognize that ARB is proposing to apply this new retirement provision only to entities with energy-based benchmarks, but we cannot support ARB employing this method in any case where an entity’s operations are not year round and highly variable year over year. This proposed amendment is particularly troubling for covered entities in the agricultural sector where seasonality, light and alternating crops (such is the case with tree nuts), and forces outside of the manufacturers control (i.e., drought and other climate conditions) impact whether an entity remains a covered entity under the Cap-and-Trade Program. We understand ARB’s intention with regard to entities that exit the Cap-and-Trade Program permanently, but it is unfair for ARB to arbitrarily penalize covered entities that come in and out of the Program based on conditions beyond their

control. To this end, we strongly urge ARB to reconsider this proposed amendment and allow retention of such allowances for a period of time, such as 5 years, to allow entities to retain such credits for future compliance obligations when they re-enter the Cap-and-Trade Program. (WONDERFUL)

Response: The commenters recommend that staff remove the amendments that require entities to return free allocation for years that the entity does not incur a compliance obligation. Staff amended the Regulation to ensure that entities return free allowances for years in which they did not incur a compliance obligation. This methodology is similar to the product-based allocation in which the true-up mechanism is used to prorate the number of allowances for the final year rather than the portion of the year the entity operated. Staff believes this amendment upholds the environmental integrity of the program by eliminating cases in which ARB distributes allowances to an entity no longer covered in the program. Allowances are provided to covered entities primarily for leakage prevention purposes. If the entity does not incur a compliance obligation, there is limited leakage risk that necessitates providing free allowances. Staff also amended the Regulation to extend the opt-in deadline for entities that were previously covered entities and drop below the Program inclusion threshold of 25,000 metric tons CO₂e a year. If entities drop below the threshold and wish to remain in the Program, they can do so under the new deadline requirements found in section 95813 of the Regulation.

B-5.8. Comment:

VI. NAIMA SUPPORTS NO ADDITIONAL CHANGES TO THE BENCHMARK FOR MINERAL WOOL MANUFACTURING

CARB has identified specific industry sectors that will be considered for changes to their benchmarks. CARB stated that “no additional sectors will be considered for changes to their benchmarks.” NAIMA supports CARB’s decision to not change the Mineral Wool Manufacturing benchmark. (NAIMA)

Response: Thank you for the support.

Miscellaneous

B-5.9. Comment:

h. If Cap-and-Trade continues, do not give out more free allowances. (EJAC)

Response: ARB chose to allocate allowances to certain major sectors for emissions leakage prevention and ratepayer protection. AB 32 requires ARB, in implementing a market-based compliance mechanism such as the Cap-and-Trade Regulation, to minimize emissions leakage to the extent feasible. ARB has chosen allowance allocation—which primarily occurs under output-based updating (an allocation methodology that changes based on annual product, not annual emissions)--as the

best way to encourage production in the State while minimizing emissions leakage. The number of allowances allocated to industrial entities will decline over time with the decline of the overall cap.

ARB also allocates allowances to natural gas suppliers and EDUs for the protection of ratepayers. Depending on the type of utility, the allowances allocated may be auctioned or used directly for compliance. Natural gas suppliers must consign a percentage of their free allowances to the auction as defined in the Regulation. IOUs must consign 100 percent of free allowances to the auction. POU's and co-ops have the choice to use the allowances for compliance or consign the allowances. The proceeds generated from consignment to auctions must be used by the utilities for protection of customers and for GHG emissions reductions. The Regulation requires utilities to annually submit information on the use of allowance value. Staff has published information on the use of allowance value at the following website:

<https://www.arb.ca.gov/cc/capandtrade/allowanceallocation/edu-ng-allowance-value.htm>

ARB has carefully vetted these allocation methodologies and held numerous public workshops finding that the current policy is appropriate for meeting the AB 32 mandate to minimize emissions leakage, as well as to protect electricity and natural gas ratepayers from Program-related rate increases. For all of these reasons, staff declines to make the requested change.

B-5.10. Comment:

At the March 29th workshop, ARB staff described the current methodology for direct allocation to the electric, natural gas, and industrial sectors. A common part of direct allocation in all three sectors is the requirement that in order to be eligible to receive the allowances calculated for each sector (and entity), an entity must: 1) comply fully with the mandatory reporting regulations (MRR) by reporting emissions and other data as required; 2) receive a positive or qualified positive verification statement pursuant to those MRR regulations; 3) fulfill all requirements for information submission necessary to receive direct allowances by the specified deadlines in the Cap-and-Trade Regulation; and 4) have an active CITSS account.

SMUD has two concerns. First, SMUD is concerned that small discrepancies in an entity's performance in MRR compliance or verification results may subject an entity to complete loss of direct allowances allocated. An entity clearly must have a CITSS account to receive allowances, but that can be set up relatively simply and quickly. The MRR requirements are voluminous and the Cap-and-Trade regulations are complicated. Entities should not lose the direct allowances they are entitled to under the methodologies for each sector due to minor discrepancies in meeting every requirement of these regulatory structures. The ARB should clarify that if the eligibility conditions are

not met in a particular instance, the ARB will consider whether direct allocations are affected, either partially or wholly, based on the nature of the “violation”.

SMUD's second concern is the description that condition 3 above – fulfillment of all requirements for information submission necessary to receive direct allowances by the specified deadlines – appears to be an ‘added’ eligibility condition that is not in Section 85980 of the Cap-and-Trade regulations. While this may be something similar to needing a CITSS account in some cases (if you don't provide the necessary information, how can CARB provide allowances), in other cases it may be again that a slight discrepancy in information provided or by when that information was provided implies no real impediment to the eventual calculation of and provision of direct allowances. Similar to the first concern, SMUD believes that ARB should be flexible in the interpretation of these questions. (SMUD)

Response: The commenter expresses concern regarding the requirements that entities fulfill to be eligible for allowance allocation, in particular MRR reporting requirements and requirements to submit all information necessary for allowance allocation. The commenter did not request any specific regulatory amendment to address its concerns and staff do not see a need for such an amendment. Either a positive or a qualified positive verification statement meets the verification requirement of Cap-and-Trade Regulation section 95890, thus allowing allocation to entities even if minor errors have occurred. Also, the time between initial reporting and final verification helps provide entities and ARB time to discuss any potential concerns. These features of MRR allow the nature of an error to be taken into account. The commenter refers to ARB's March 29, 2017 workshop when discussing the requirement for entities to submit all information necessary. This statement was intended to summarize the requirements for diverse entities which are listed in section 95890 and to reflect that ARB cannot allocate if it does not have the necessary information, some of which is provided by entities themselves. The workshop information was not referring to a new requirement.

B-5.11. Comment:

True-up Action Transparency - Staff will True-up allowance allocations based on updated production data. This could have a significant impact on allowance planning and auction participation . Staff should be required to provide entities with a proposed True-up action report prior to making any changes in CITSS. (SOLARTURBINES)

Response: ARB staff already provides full transparency for allowance allocation. All allowance allocation equations and factors are provided in the Regulation. An entity is able to perform these calculations itself using entity-specific, CBI production data. After allowance allocation has been distributed to industrial entities, entities may send a request to ARB staff to provide detailed calculations of the allowance allocation. Staff can only provide these details after the allocation is finalized and distributed in the Compliance Instrument Tracking System Service (CITSS).

B-5.12. Comment:

IV. U.S. DEPARTMENT OF COMMERCE IDENTIFIES FIBER GLASS INSULATION AS GREEN MANUFACTURER AND GREEN PRODUCTS

The U.S. Department of Commerce issued a report, “Measuring the Green Economy,” that defined green products and jobs “as those whose predominant function serves one or both of these two goals:

- Conserve Energy and Other Natural Resources...
- Reduce Pollution.”⁸⁵

Given these criteria, insulation materials are identified as green products because they both save energy and reduce pollution.⁸⁶ The fiber glass industry is also specifically identified by the Department of Commerce as among the manufacturing codes that are deemed green:

3279931111	Loose fiber (blowing and pouring) (shipped as such) and granulated fiber, mineral wool for thermal and acoustical envelope insulation (for insulating homes and commercial and industrial buildings)
3279931211	Building batts, blankets, and rolls in thermal resistance (R) values R19 or more, mineral wool for thermal and acoustical envelope insulation (for insulating homes and commercial and industrial buildings)
3279931311	Building batts, blankets, and rolls in thermal resistance (R) values R11 to R18.9, mineral wool for thermal and acoustical envelope insulation (for insulating homes and commercial and industrial buildings)
3279931321	Building batts, blankets, and rolls in thermal resistance (R) values R10.9 or less, mineral wool for thermal and acoustical envelope insulation (for insulating homes and commercial and industrial buildings)
3279931411	Acoustical (wall and ceiling) sold as acoustical insulation, mineral wool for thermal and acoustical envelope insulation (for homes and commercial and industrial buildings)

V. ENVIRONMENTAL BENEFITS OF INSULATION

⁸⁵ “Measuring the Green Economy,” U.S. Department of Commerce, Economics and Statistics Administration, April 2010, p. 5.

⁸⁶ “Measuring the Green Economy,” U.S. Department of Commerce, Economics and Statistics Administration, April 2010, p. 8.

In issuing its final regulations, it is important for CARB to recognize that improving the energy efficiency in new and existing buildings can deliver significant reductions in greenhouse gas emissions, thus promoting the ultimate goal of AB 32. Insulation is the most cost-effective means of improving energy efficiency in buildings. It is, therefore, the most cost-effective means of reducing greenhouse gas emissions. This fact was confirmed in studies conducted by the Harvard School of Public Health in 2002 and 2003.⁸⁷ These Harvard studies were recently updated by Boston University. The findings included specific reductions in greenhouse gases in addition to criteria pollutants.

The Boston University update focused on how much energy could be saved if all single-family homes across the continental United States in 2013 were insulated to the levels mandated by the 2012 International Energy Conservation Code. With that premise, Boston University determined that 37 TWh of electricity would be saved every year; this is a 3.4 percent reduction in residential electricity consumption. A similar analysis was performed for natural gas consumption, LPG/propane, and fuel oil consumption. The increased insulation reduced natural gas consumption by 360 billion standard cubic feet every year. LPG/propane consumption was reduced by 490 million gallons annually and fuel oil was reduced by 480 million gallons a year.

More importantly, Boston University calculated the energy savings into annual reductions of pollutants. Specifically, reductions in electricity consumption would result in annual reductions of 80 million tons of CO₂, 68,000 tons of NO_x, and 120,000 tons of SO₂. Reduction in direct residential combustion would result in annual reduction of 30 million tons of CO₂, 25,000 tons of NO_x, 10,000 tons of SO₂, 1,200 tons of VOCs, and 600 tons of primary PM_{2.5}.⁸⁸

Figure 3 from the article effectively illustrates the breadth of the pollution reduction achieved through increased insulation:

allows us to quantify the benefits of energy efficiency on a national scale not seen before, which takes us far beyond energy savings and energy security. Now it is clear

⁸⁷ Jonathan I. Levy, Yurika Nishioka and John D. Spengler, "The public health benefits of insulation retrofits in existing housing in the United States," *Environmental Health: A Global Access Science Source*, April 2003, pp.1-16 and Yurika Nishioka, Jonathan I. Levy, Gregory A. Norris, Andrew Wilson, Patrick Hofstetter, and John D. Spengler, "Integrating Risk Assessment and Life Cycle Assessment: A Case Study of Insulation," *Risk Analysis*, Vol. 22, No. 5, 2002, pp. 1003-1017. The findings by the Harvard School of Public Health demonstrated the dramatic correlation between the benefits of increased insulation and reduction of air emissions. These Harvard researchers stated that the "magnitude of the economic and public health benefits indicates that creative public policies to encourage" increased insulation "may be warranted." Jonathan I. Levy, Yurika Nishioka and John D. Spengler, "The public health benefits of insulation retrofits in existing housing in the United States," *Environmental Health: A Global Access Science Source*, April 2003, p.14. The Harvard researchers concluded that "[t]his approach

⁸⁸ Jonathan I. Levy, May K. Woo, Stefani L. Penn, Mohammad Omari, Yann Tambouret, Chloe S. Kim and Saravanan Arunachalam, "Carbon reduction and health co-benefits from US residential energy efficiency measures," *Environmental Research Letter*, 11(2016)034017, p. 4.

that improving energy efficiency not only helps us as a nation, but also has an immediate, positive impact on us, as individuals, and our families.” NAIMA “Harvard Study Findings,” NAIMA-036, September 2003.

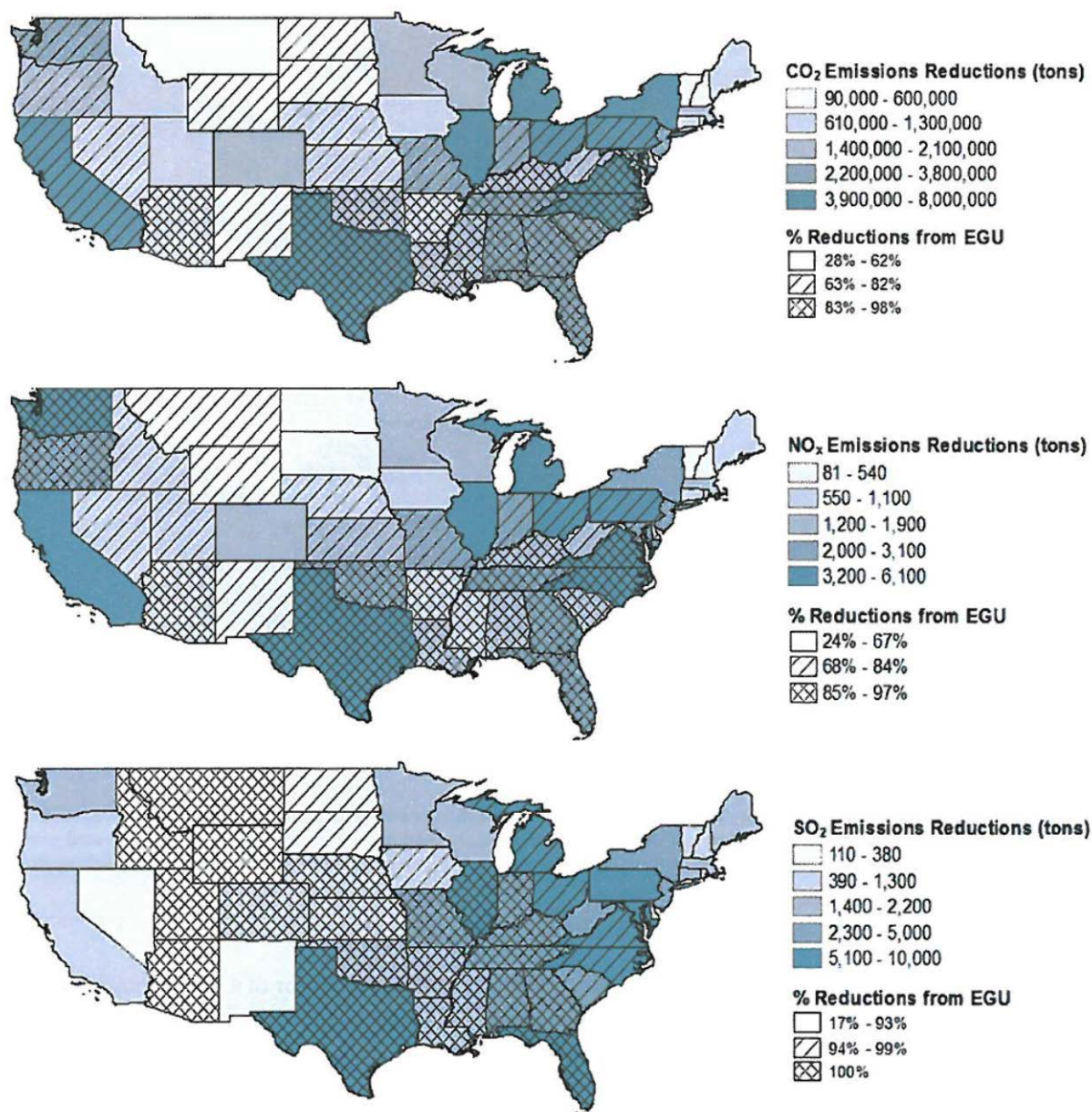


Figure 3. Annual reduction in emissions associated with increased residential insulation and the fraction of the reduction from EGUs versus residential combustion sources.

Boston University also looked at building new homes with increased insulation to 2012 levels. Here again, improving the energy efficiency in new homes provided sizable

reductions in pollutants. Table 3 and Table 4 from the article illustrate the magnitude of pollution reduction that can be achieved through insulation⁸⁹:

Table 3

Annual residential combustion emission reductions associated with increasing residential insulation for new homes to IECC 2012 levels, by state. All values are rounded to two significant figures.

State	NO _x (pounds)	SO ₂ (pounds)	PM _{2.5} (pounds)	CO ₂ (tons)
AL	910	5.8	4.1	580
AR	1800	11	7.9	1100
AZ	1200	7.8	5.6	790
CO	3200	20	15	2000
CT	530	120	34	290
FL	260	1.6	1.1	150
GA	3600	48	16	2100
ID	1100	6.9	4.9	690
IN	2800	30	200	1700
KS	3200	55	510	1900
KY	1200	7.5	5.4	750
LA	720	4.5	3.3	460
ME	1500	380	96	830
MI	2400	23	120	1500
MN	5600	76	590	3500
MO	5500	86	740	3400
MS	600	3.8	2.7	380
NC	5900	50	24	3300
ND	2200	27	190	1400
NE	610	8.6	70	370
NH	550	140	35	300
NJ	6100	230	36	3800
NM	1200	7.4	5.3	740
NV	2300	14	10	1400
NY	4300	170	26	2700
OH	2400	25	160	1500
OK	3400	21	15	2100
OR	650	6.1	31	410
PA	4600	210	29	2800
SC	2500	22	10	1400
SD	1200	16	120	770
TN	2300	15	11	1500
TX	9500	60	43	6000
UT	4000	25	18	2500
VT	400	98	24	220
WI	3300	32	180	2000
WV	500	11	2.5	300
WY	750	4.7	3.4	470
Total	95,000	2100	3400	58,000

Table 4

Annual power plant emission reductions associated with increasing residential insulation for new homes to IECC 2012 levels, by state. All values are rounded to two significant figures.

State	SO ₂ (pounds)	NO _x (pounds)	CO ₂ (tons)
AL	38,000	19,000	12,000
AR	30,000	20,000	11,000
AZ	2200	7700	5200
CO	4200	6100	3200
CT	300	300	200
FL	32,000	16,000	10,000
GA	110,000	57,000	36,000
ID	1100	2500	1000
IN	18,000	7000	3700
KS	23,000	21,000	9800
KY	43,000	21,000	14,000
LA	16,000	11,000	5900
ME	600	600	400
MI	12,000	4500	2400
MN	41,000	24,000	13,000
MO	50,000	33,000	17,000
MS	22,000	11,000	7100
NC	180,000	89,000	57,000
ND	15,000	8800	4800
NE	4400	2600	1400
NH	300	300	200
NJ	30,000	12,000	6600
NM	2100	4200	2300
NV	4000	13,000	8700
NY	5400	4700	3100
OH	13,000	4900	2600
OK	51,000	49,000	22,000
OR	1400	2800	1100
PA	25,000	10,000	5300
SC	94,000	47,000	30,000
SD	8800	5600	3000
TN	98,000	49,000	32,000
TX	130,000	86,000	66,000
UT	3500	8500	3200
VT	200	200	100
WI	14,000	6900	3800
WV	13,000	5100	2700
WY	800	1300	600
Total	1,100,000	670,000	410,000

Both the Harvard School of Public Health and Boston University updates confirm that insulation's most significant environmental attribute is saving energy which, in turn, delivers significant pollution reductions.

Indeed, both energy efficiency and insulation products are resources. In fact, energy efficiency, including insulation, has been deemed the greatest untapped resource available to address the current energy crisis and climate change.⁹⁰ Unlike other energy efficiency measures, such as energy efficient appliances or energy saving light bulbs, insulation, once installed, requires no additional energy to save energy.

89 Jonathan I. Levy, May K. Woo, Yann Tambouret, "Energy savings and emission reductions associated with increased insulation in new homes in the United States," *Building and Environment*, 96 (2016) 72-79, p. 77.

90 "Transforming Energy Efficiency," <http://www.duke-energy.com/docs/CGI%20-%20Fact-Sheet.doc>, September 27, 2007.

Fiber glass insulation also has consistently high recycled content. Since 1992, NAIMA has conducted an annual survey of member companies to determine the volume of glass cullet used by NAIMA's members. The most recent survey showed that in 2015, NAIMA's member companies in the United States used more than 1.7 billion pounds of recycled glass. The data for Canadian facilities showed that in 2015, 373 million pounds of recycled glass was used in the production of fiber glass insulation. That is a total of 2 billion pounds of recycled glass used in 2015.

Since 1992, when NAIMA started collecting recycled data, 52 billion pounds of recycled material have been diverted from the waste stream. These numbers place fiber glass insulation as the second largest user of glass cullet in North America. Fiber glass insulation manufacturers are also the highest users of mixed bottle cullet (a mix of flint, amber, and green) and, as such, are responsible for recycling more of this material than any other source.

By using glass cullet, raw materials (sand, soda ash, etc.) use will be reduced, energy in producing the raw materials will be decreased, and the life of the furnaces will increase up to 30 percent due to decreased melting temperatures and a less corrosive batch. Reports have shown that compared to 100 percent raw materials, using 30 percent glass cullet reduces silica use by 60 percent, soda ash by 40 percent, and saves 10 percent in energy costs.⁹¹

NAIMA's members are committed to continued use of clean cullet. CARB should ensure its final regulations promote, rather than discourage, the Fiber Glass insulation industry and its green products. (NAIMA)

Response: The commenter asserts several environmental benefits achieved by the use and increased adoption of fiberglass industry products. These asserted benefits relate to overall AB 32 goals and the proposed 2017 Scoping Plan Update. The commenter requests that ARB's Cap-and-Trade Regulation not have the effect of limiting these environmental benefits. Staff believes the proposed amendments do not discourage any of these environmental benefits, as the Cap-and-Trade Program merely requires entities who emit above the GHG emissions program inclusion threshold to meet their obligation by surrendering an equivalent number of compliance instruments. Further, because the Cap-and-Trade Program incentivizes energy efficiency, the Program already incentivizes installation of insulation and the use of raw materials (like glass cullet) that decrease energy use.

Moreover, ARB allocates allowances to fiberglass producers as part of AB 32's mandate to minimize emissions leakage to the extent feasible. This product-based allocation is calculated using an emissions efficiency benchmark, and

91 Berkeley National Laboratory, *Energy Efficiency Improvement and Cost Saving Opportunities for the Glass Industry: An Energy Star Guide for Energy and Plant Managers*, March 2008, pp. 67-68.

allocation increases (decreases) based on increases (decreases) in fiberglass output.

B-6. Leakage Prevention

Measurement Metrics

B-6.1. Multiple Comments:

We encourage ARB to adopt a goal to develop methodology that will prevent domestic and international leakage where California facilities do not compete on equal regulatory climate change footing. Leakage undermines our ability to maintain jobs and sustainably produce local products for Californians. While the proposed approach addresses leakage, we do not yet believe this approach does enough to prevent leakage for California covered entities. (GRAPHICPACKAGING)

Comment:

Additional Trade Exposure Protection is Necessary

In the last round of amendments to the cap-and-trade regulation ARB extended full industry assistance factor into the second compliance period. Today, California's market remains largely isolated from other markets where more cost-effective reductions exist, as it was in the 2013-2014 timeframe. Accordingly, an extension of the same full industry assistance is still warranted until such time that leakage risk is eliminated, both to maintain the environmental integrity of the program and to protect California jobs and the state economy.

Reductions in GHGs are driven by the cap, not by allowance allocation. Reductions in GHGs are improved if the state minimizes leakage as required in AB 32 38562(b)(7) because leakage causes emissions outside of the cap to increase. The program can better meet California's climate goals by extending the full industry assistance factor. Emission reductions will continue to occur because industry does not receive allowances over the cap. For these reasons, we recommend that ARB extend full industry assistance factor into future compliance periods. (CCPC)

Comment:

TRADE EXPOSURE PROTECTION IS NECESSARY

The risk of leakage due to costs incurred by California industry, but not their competitors is high. In the last round of amendments to the Cap and Trade regulation (2013-2014), CARB extended 100% of the assistance factor into the second compliance period. As it was in the 2013-2014 timeframe, California's market remains largely isolated from other markets where more cost-effective reductions exist.

Accordingly, an extension of 100% industry assistance is still warranted until such time that leakage risk is eliminated, both to maintain the environmental integrity of the

program and to protect California jobs and the state economy.
(CALCHAMBERCOMMERCE)

Comment:

Let me turn quickly to trade exposure. California's market is subject to imports from markets without carbon regulations. There's still no policy or economic justification for reducing industry assistance factors. ARB's current proposals threaten both the environmental integrity of the program by promoting emissions leakage and loss of economic productivity and jobs to unregulated jurisdictions. It's also disregarding the fact that regulated entities are going to face increasingly stringent cap and trade compliance obligations because of the declining cap.

And so we would recommend that ARB extend the current assistance factors into future compliance periods. (WSPA2)

Comment:

Maintain Industry Assistance at 100 percent

In response to the lack of detail on the proposed changes to the industry assistance, CMTA would recommend that ARB maintain industry assistance at 100 percent through the Third Compliance Period. This change would delete the planned drops for medium and low leakage risk categories to 75 and 50-percent.

California manufacturers support the development of a well-designed cap and trade program in order to provide a cost-effective mechanism for reducing GHG emissions.
(CMTA)

Comment:

Some elements are also missing from this package and we would like to point out that industry remains trade exposed, that we still face competition from other jurisdictions that do not have carbon costs. Therefore, we would recommend that the Board at least direct staff to reconsider reopening the 2018 trade exposure requirements so that industry does not face a 25 percent reduction in its allowances.

And again, we would try to point out that those allowances, although they may seem like a lot, represent less than 3 percent of cap-and-trade revenue, and yet they make a huge difference to the competition of industry in California. (CHEVRON)

Comment:

CSCME strongly supports the continuation of the allowance allocation program as an essential ingredient for promoting the long-term success of California's efforts to address global climate change. (CSCME)

Comment:

One thing I wanted to -- a couple things I want to address specifically, industry assistance. In the proposal, we appreciate staff stepping back from the initial discussion regarding addressing -- or reducing industry assistance in the third compliance period beyond what's already on the books.

In fact, we would argue -- we would request that ARB look at extending the 100 percent industry assistance through the third compliance period, as we have yet to see the full adoption and partnership with a number of other jurisdictions in our Cap-and-Trade Program that we had promise -- been promised and expected to see those years ago when AB 32 was originally passed.

So we do believe that it will be appropriate in -- the interests of protecting against leakage, in the interests of protecting California manufacturers against the competitive disadvantage that would be generated by a much significant increase in compliance costs. (CMTA2)

Comment:

...regarding slide 6, CCPC urges the Board and staff to expand industry -- the industry assistance factor of the second compliance period to the third compliance period to protect regulated communities, and to keep costs lower in the program. (CCPC2)

Comment:

First of all, I want to thank the Board. With the recent release of the food processing study that you ordered back in 2011, you know, we are very much pleased with that, and we believe that it shows that we are in line for a possible adjustment in third compliance period for 100 percent allowances, and we want to work with the staff on that to see that that goes forward. It really would take a lot of pressure off our members. (FOODPROCESSORS2)

Response: The commenters request an indefinite extension of 100 percent assistance factors for medium and low leakage risk sectors. In the more immediate future, commenters request an extension of 100 percent assistance factors for medium and low leakage risk sectors to the third compliance period (2018 to 2020).

Allowance allocation is scheduled to be reduced starting with 2018 allocation. In the 2013 rulemaking, ARB accommodated a longer adjustment (i.e., transition) period by medium and low leakage risk sectors so that they can successfully operate with a carbon signal. As a result of the 2013 rulemaking, industries at medium and low risk of leakage received an additional three years of 100 percent assistance factors, delaying the reduction in assistance factors from 2015 to 2018.

In light of the 2013 rulemaking's three-year extension of 100 percent assistance factors from 2015 through 2017, and increase in 2018 through 2020 allocation to

medium and low leakage risk sectors, staff chose not to address 2018 through 2020 allocation during the current 2016 rulemaking, and notes that the requested changes are outside the scope of the current rulemaking.

Providing high levels of allowance allocation to medium and low leakage risk⁹² sectors beyond the initial 2013 through 2017 period exceeds the allowance allocation necessary to minimize emissions leakage.⁹³ From 2013 through 2017, these facilities received these high levels of allocation to help “California manufacturers... invest in cost-effective emissions reductions.... The [transition] assistance in early years... help[s] promote a smooth transition to a low-carbon economy. Assistance rates... decline as the covered entities gradually adjust to the carbon price and adopt energy- and carbon-saving strategies.”⁹⁴

In other words, these medium and low leakage risk sectors are expected to have invested in carbon-saving initiatives and technologies in the eight years they have anticipated a reduction in allowance allocation⁹⁵ and received transition assistance. The medium and low leakage risk sectors should now be able to bear some portion of the GHG cost without experiencing sector-wide emissions leakage. Options available to the facilities to successfully operate with the reduction in allowance allocation include cost pass-through⁹⁶ and investments in further carbon-saving technologies.⁹⁷ Market advantages, such as transportation cost differentials between in-state and out-of-state importers of products to California can serve to provide a natural cost advantage for in-state producers in serving California demand.⁹⁸ Therefore, for medium and low leakage risk sectors, due to ample time to prepare for less assistance and multiple options with which to do so, 100 percent assistance factors would exceed the level of compensation necessary to minimize emissions leakage.

⁹² The methodology that selects these sectors is defined in the 2010 Appendix K, and the sectors themselves are identified in Table 8-1 of the current regulation as having 75 percent (medium leakage risk) and 50 percent assistance factors (low leakage risk) in the 2018 through 2020 AF columns.

⁹³ ARB provides allowance allocation to industrial sectors to minimize emissions leakage to the extent feasible. Under ARB’s chosen allowance allocation method, sectors are awarded allowances at a fixed rate per unit of output produced in California. By design, this method ensures that increases in California production are encouraged (via allowance allocation), whereas increases in GHG without a commensurate increase in California production results in a higher compliance obligation without additional allowances. Assistance factors determine what fraction of a sector’s fixed expected emissions per unit product (i.e., benchmark) will be covered by allowance allocation.

⁹⁴ 2010 ISOR Volume IV “Appendix J: Allowance Allocation.” Section 4.a. p. 18-19:

<https://arb.ca.gov/regact/2010/capandtrade10/capv4appj.pdf>

⁹⁵ From the 2010 ISOR to the end of 2017

⁹⁶ Cost pass-through can either be a pass-through of the carbon obligation to upstream suppliers, or a pass-through of carbon costs to purchasers of the sector’s products.

⁹⁷ Investing in carbon-saving technologies reduces a facility’s compliance obligation per unit of product, reducing the fraction of the facility’s emissions that are not matched by free allowance allocation

⁹⁸ 2010 ISOR Volume IV Appendix L, “Economic and Allocation Advisory Committee Recommendations,” pL-21 footnote 20 <https://www.arb.ca.gov/regact/2010/capandtrade10/capv4appl.pdf>

At a longer time scale, indefinite extension of 100 percent assistance factors to minimize emissions leakage is also unwarranted. ARB has a mandate to minimize emissions leakage, but has calculated through the 2010 Appendix K leakage assessment⁹⁹ that full allowance allocation is neither necessary nor appropriate to minimize emissions leakage in all industrial sectors. Under the 2010 Appendix K methodology, 100 percent assistance factors are designated for high emissions leakage risk sectors, and used for high leakage risk sectors' allocation through 2020. Post-2020 assistance factors have not yet been determined.

WSPA states that there is no policy or economic justification for reducing industry assistance factors to medium and low leakage risk sectors. Staff disagrees. There are long-term consequences to extending 100 percent assistance factors to these sectors when transition assistance is no longer required (the extension that is requested by the commenters). In the words of the Economic and Allocation Advisory Committee, industrial allowance allocation “reduces the variable cost of production [and]... results in fewer reductions in emissions associated with [the allocated sectors'] products and thus necessitates greater reductions and higher price increases in other sectors in order to meet the overall emissions cap. This... leads to higher economy-wide costs... [but helps] address emissions leakage.”¹⁰⁰ Allocation above levels necessary to minimize emissions leakage to the extent feasible would unnecessarily reduce allowance value available for other beneficial uses, including reducing the number of State-owned allowances made available for purchase at auction and any resulting proceeds to the GGRF, and decrease the cost-effectiveness of the Cap-and-Trade Program.

ARB will have an opportunity to review if the current 2010 Appendix K methodology should be updated or refined, including for medium and low leakage risk sectors. As stated in the second 15-day notice, “After the current 2016 rulemaking concludes, staff will initiate a deliberative process with input from industrial, environmental justice, environmental groups, and other interested stakeholders to establish a robust and transparent framework for establishing post-2020 assistance factors, and will propose assistance factors and industrial allocation for post-2020 compliance periods before the start of post-2020 allocation.”¹⁰¹ Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

⁹⁹ <https://www.arb.ca.gov/regact/2010/capandtrade10/capv4appk.pdf>

¹⁰⁰ <https://www.arb.ca.gov/regact/2010/capandtrade10/capv4appl.pdf> p. L-20

¹⁰¹ 2016 Rulemaking 2nd 15-day Notice, “Section J: Modifications to Section 95871. Disposition of Allowances from Vintage Year 2021 and Beyond”:
<https://www.arb.ca.gov/regact/2016/capandtrade16/2nd15daynot.pdf>

Graphic Packaging requests ARB establish a goal to prevent domestic and international leakage. AB 32 already directs ARB to minimize emissions leakage to the extent feasible as ARB implements the Cap-and-Trade Program.

B-6.2. Multiple Comments:

Graphic Packaging International asks that ARB direct staff to work with each affected industrial sector in the development of the assistance factors for that sector. We note that the current approach does not require that staff will work with industry or even allow for critical industry trade data to be incorporated with the theoretical domestic and international leakage analyses performed. We worked very effectively with ARB in 2011-12 in the development of the assistance factors currently used for our industry, providing key industry trade data. We hope to work with ARB in this same capacity as new assistance factors are established through 2030. Please direct staff to work with industry and incorporate industry trade data into the development of industry assistance factors. (GRAPHICPACKAGING2)

Comment:

Graphic Packaging International appreciates the theoretical analyses that has been conducted for domestic and international leakage. It represents solid, critical thinking as to what should or might happen in the marketplace. What is unsettling about the ARB approach is that these theoretical analyses are solely based on business school theory and some data prior to 2013 before California's cap and trade program was implemented. No effort has been made to validate the theory with present day data to determine what output has actually been lost from 2013-15 since cap and trade begun. Theory must be validated before putting it to use. Industry can provide insight into the actual impact the cap and trade program has had on lost output, if not actual data in the 2013-15 period, and the current competitive pressures it faces from international and domestic entities without a similar cap and trade program. We encourage ARB to validate these theoretical approaches with actual, recent trade data wherever possible and work with industry to gain insight as to the impact that the cap and trade program has had and the real competitive pressures facing California energy-intensive, trade-exposed entities. (GRAPHICPACKAGING3)

Response: Graphic Packaging requests that ARB staff work with industry to establish post-2020 assistance factors. While appreciative of the commissioned studies, Graphic Packaging requests (1) the studies be updated with recent data post-implementation of the Cap-and-Trade Program and (2) staff find a way to validate the approach and results of the studies with recent trade data.

With respect to considering data from industry, staff is open to meeting with industry and considering industry data. In addition to workshops, staff has met extensively with industry before and during the 2016 rulemaking process and

considered industry-supplied information.¹⁰² And, as indicated in response to 45-day comment B-6.1, and in the second 15-day notice, “[a]fter the current 2016 rulemaking concludes, staff will initiate a deliberative process with input from industrial, environmental justice, environmental groups, and other interested stakeholders to establish a robust and transparent framework for establishing post-2020 assistance factors, and will propose assistance factors and industrial allocation for post-2020 compliance periods before the start of post-2020 allocation.”

With respect to validating the approach and results of the studies with recent trade data and industry insight, the international study used recent international trade data (2010 through 2014) to estimate some of the inputs to each sector’s international market transfer. Staff has a strong preference for using business data¹⁰³ in informing proposed assistance factors rather than industry insight or supposition about future market conditions. Should market conditions significantly change during the post-2020 period, staff is open to future rulemakings to review and modify post-2020 assistance factors as necessary.¹⁰⁴ Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Before and during the 2016 rulemaking, ARB invited industry to provide alternate post-2020 AF methodologies independent of the method outlined in the 2016 Appendix E and Attachment B. Multiple industries did so.

B-6.3. Comment:

Proposed Changes in CARB Methodology for Estimating Leakage Risk

In light of the proposal to develop a new metric for assessing leakage risk CARB must be willing to do the necessary work in order to assure each of the industry stakeholders that their AFs will be based on the best available data. For instance, any leakage analysis should include a discussion and analysis of the upstream and downstream impacts on regulated and/or nonregulated entities. For example, economic impacts to cheese producers would have an impact on downstream products (i.e., protein and lactose) as well as upstream suppliers to the cheese producers (i.e., dairies, etc.).

¹⁰² Staff considered industry-supplied public data, as well as confidential business information. When appropriate, industry-supplied data directly resulted in revisions to the assistance factors proposed in the 2016 1st 15-day package.

¹⁰³ Either from government sources, or reputable or verified industry data sources.

¹⁰⁴ Staff has already demonstrated the ability to make mid-course corrections as needed to industrial allowance allocation. During previous rulemakings (e.g. with the 2013 rulemaking) staff made modification of 2015 through 2020 assistance factors, established other assistance factors, and revised industry benchmarks as appropriate.

For the food processing industry, CARB's path is clear. Given the uniqueness of the industry, special emphasis must be employed to account for the variables in our markets that exist in no other industries. The Hamilton et. al. study is a good start, and makes a strong and, to date, unrefuted argument for continuing 100% transition assistance for food processors beginning 2018. As for post-2020 metrics, both the Fowlie Study and the RFF Study need to be augmented to accurately reflect the market demands present in the food processing industry. (FOODPROCESSORS)

Response: CLFP requests that staff "assure each of the industry stakeholders that their assistance factors will be based on the best available data," and requests ARB use the Hamilton et. al. study¹⁰⁵ for food processor assistance factors as it "makes a strong... argument for continuing 100% transition assistance for food processors beginning 2018."¹⁰⁶ See the response to the 45-day comment B-6.1 regarding the rationale for ending transition assistance starting with 2018 allowance allocation, the reason 100 percent assistance factors are inappropriate if they exceed the compensation necessary to minimize leakage in a sector,¹⁰⁷ and for the significant accommodations that have already been made to help industry adjust to a carbon signal during the third compliance period. In removing proposed post-2020 assistance factors from this rulemaking in the second 15-day change package, staff have not established a post-2020 assistance factor methodology that would translate the Hamilton findings into specific assistance factors for the four studied food processor sectors. However, staff notes that if we were to use the market transfer rates from the Hamilton study, it would result in a 76 percent assistance factor for wet corn milling and lower assistance factors for the other three studied sectors.¹⁰⁸

As stated in the second 15-day notice, "staff is committed to continuing to provide industrial allowance allocation at levels sufficient to minimize emissions leakage for the post-2020 period to meet the AB 32 requirement to minimize emissions leakage to the extent feasible. Minimizing emissions leakage for the post-2020 period is important as the rate of reductions to achieve the 2030 target is steeper than the existing rate to achieve the 2020 target."¹⁰⁹ Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB

¹⁰⁵ Hamilton, Stephen, et. al., "Production and Emissions Leakage from California's Cap-and-Trade Program in Food Processing Industries: Case Study of Tomato, Sugar, Wet Corn and Cheese Markets" May, 2016. <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/calpoly-food-process-leakage.pdf>

¹⁰⁶ CLFP's 45-day comment B-6.10.

¹⁰⁷ These sectors are currently identified via the 2010 Appendix K methodology

¹⁰⁸ Market transfer rate found on slide 21:

<https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/calpoly-food-process-leakage-pres.pdf>

¹⁰⁹ 2016 Rulemaking 2nd 15-day Notice, "Section J: Modifications to Section 95871. Disposition of Allowances from Vintage Year 2021 and Beyond":

<https://www.arb.ca.gov/regact/2016/capandtrade16/2nd15daynot.pdf>

will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Leakage Studies

B-6.4. Comment:

Graphic Packaging International found the domestic leakage analysis detailed enough to where the Value Added impact and Output impact were determined as a function of potential Assistance Factors by industrial sector. This was very helpful. Unfortunately, the international leakage analysis was not as detailed and did not provided these numerical results. As we have several competitors from China and other Asian countries, we ask that ARB develop the same Value Added impact and Output impact for international leakage too. Furthermore, we also understand that the international leakage analysis focused on China, but we ask that ARB expand the international analysis to include other Asian countries as well, as we compete with companies from several Asian countries in the recycled paperboard industry. (GRAPHICPACKAGING4)

Response: Graphic Packaging requests that the international analysis be broadened beyond an analysis of China. Staff notes that the international study considered imports and exports from and to all nations using U.S. Census Bureau international trade data, and therefore includes consideration of other countries in addition to China.

Graphic Packaging also requests the release of more detailed numerical results from the international study. In response to stakeholder requests for the details and numbers underpinning the international leakage study, ARB released the full international dataset on October 21, 2016.¹¹⁰

B-6.5. Comment:

4.2 CARB's Proposed Approach Relies on Studies that are Conceptually Flawed

In the simplest of terms, both the domestic and international leakage studies undertake a two-step process: (1) analyze historical data to estimate the relationship between energy prices and key outcomes for individual industries and (2) simulate the effect of a given carbon price on individual industries assuming that the historical relationships remain unchanged. In short, they attempt to “analyze by analogy.” However, for a variety of reasons, the analogy is unlikely to hold true in practice, particularly for the cement industry. Specifically,

- The past is unlikely to be a reliable predictor of the future. The economic circumstances during the studies’ timeframes (1997-2012) encompass the bursting of an unprecedented housing bubble, the sudden onset of a global financial crisis, and one of the most severe recessions in U.S. history. Since the

¹¹⁰ October 21, 2016 – Cap-and-Trade Regulation Amendments Workshop “International Leakage Study Dataset” <https://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm>

end of the recession, the U.S. economy has been locked in a so-called “new normal” that includes a slow and sluggish economic recovery, ultra-low interest rates, an unusually strong dollar, and historic levels of overcapacity in key commodities, including cement, aluminum, steel, and petroleum. Simply put, the conditions of competition have radically changed. As a result, even if the economic relationships during the 1997-2012 timeframe could be accurately estimated, they are unlikely to bear any resemblance to today, much less 2021 and beyond.

- Positive cost shocks are not equivalent to negative cost shocks. An industry’s response to a positive energy cost shock (e.g., a decline in natural gas prices) is likely to be different than its response to a negative energy cost shock (e.g., an increase in carbon prices).¹¹¹
- Gradual cost shocks are not equivalent to sudden cost shocks. An industry’s response to energy prices that have gradually evolved over many years is likely to be different than its response to a sudden and severe cost increase that would occur for industries that experience a significant reduction in their leakage assistance.
- Transitory cost shocks are not equivalent to permanent cost shocks. An industry’s response to a potentially temporary cost shock (i.e., a market-driven cost decrease in natural gas prices) is likely to be different than the response to an unambiguously permanent cost shock (i.e., a policy-driven cost increase via carbon pricing).
- Private cost shocks are not equivalent to public cost shocks. A competitor’s response to a relatively private cost shock, such as small and highly uncertain changes in a California producer’s energy cost structure, are likely to be different than the response to a very public cost shock, such as a large and highly certain increase in carbon costs. Put differently, a highly visible, policy-induced carbon price shock will more clearly signal an opportunity for out-of-state producers that can logistically and economically access the California market.

4.3 CARB’s Proposed Approach is Not Relevant to the Cement Industry

Despite CARB’s assertions that its revised methodology “more precisely” measures an industry’s leakage risk, there are several reasons to believe that its estimates of leakage risk for the cement industry are “precisely” wrong. Both studies fail to take critical features of the California cement industry into account in their analysis, which raises serious questions about their ability to more accurately assess leakage risk in the cement industry.

¹¹¹ For example, see Engemann, Kristie et al. (2012) at 1, which notes that there is “general acceptance that oil price shocks are directionally asymmetric: large positive oil-price shocks matter, but negative ones do not.”

- Neither study formally considers the impact of process emissions. Process emissions constitute the majority of GHG emissions in the cement industry, and neither study considers the impact of process emissions in their formal modeling work. As a result, the modeling results will understate the impact of a given carbon price on the cement industry by at least half, and perhaps more if impacts are found to be non-linear at much higher values.
- Neither study accurately captures the cement industry's energy costs. Coal constitutes the vast majority of energy consumed in the California cement industry, and electricity and natural gas comprise only a small share of the industry's cost structure. Nevertheless, both studies focus on the impact of electricity and natural gas prices, and there is no indication that they include or otherwise control for variation in coal prices or the impacts of the use of alternative or biogenic fuels in their models. As a result, the modeling results are unlikely to accurately estimate the impact of a given carbon price on the cement industry.
- Neither study accurately captures the potential for inter-industry leakage. In addition to imported cement, California cement producers compete for market share against other construction materials, including asphalt, glass, steel, and lumber. Although both studies attempt to assess the potential for intra-industry leakage (e.g., shifts in production from California cement producers to non-California cement producers), neither seems to consider or evaluate the potential for inter-industry leakage (e.g., shifts in production from California cement producers to non-California producers of cement substitutes). To the extent that a carbon price results in a shift in market share toward substitute products that are manufactured outside the state and transported to California for consumption, the modeling results are likely to understate the impact of a given carbon price on the cement industry.
- The international leakage study does not accurately capture the conditions of competition in the California cement industry. The international leakage study is effectively an analysis of industries at the national level, yet the national cement industry and the California cement industry are fundamentally different in important respects. As evidenced by more than two decades of U.S. International Trade Commission rulings, the California cement industry is a distinct regional market that operates in a competitive environment that is fundamentally different than cement industries in other U.S. regions or in the United States as a whole. Unlike inland states, the California market is logistically and economically accessible by seaborne vessels from virtually every port in the Asia Pacific region, which amplifies the mere threat of imports and forces domestic producers to proactively suppress prices, profits, and investment to maintain market share and achieve the high utilization rates needed in a capital-intensive industry. On the other hand, the California cement industry

exports very little cement due to structural, geographic, and political barriers. As a result, the international leakage study's inherently national approach is unlikely to accurately simulate the impact of a given carbon price on the California cement industry.

(CSCME)

Response: CSCME provides three broad categories of concerns in their comment: the studies are based on a historical timeframe that CSCME believes is different from the markets currently facing producers; the cost shocks used to approximate carbon responses do not match CSCME's assessment of the impact of a carbon compliance obligation without allowance allocation; the Californian cement industry has features that make it difficult for a national-level study to measure the leakage risk for California cement. As indicated in previous responses, staff has postponed development of a post-2020 assistance factor framework and sector-specific post-2020 assistance factors until a subsequent rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.6. Comment:

I. THE IMPORTANCE OF MINIMIZING LEAKAGE THROUGH ALLOWANCE ALLOCATIONS

Leakage can have diverse, profound, and potentially irreversible consequences for the economic viability of entire industries, for the environmental integrity of the cap-and-trade program, and for the long-term political durability of AB 32. Accordingly, it is imperative that CARB develop an allowance allocation framework that effectively and efficiently minimizes leakage, particularly in high-risk industries.

The imperative to minimize leakage is illustrated and underscored by certain key findings in the recently released leakage studies, which were commissioned by CARB and now serve as the centerpiece of its proposed approach. For example, the domestic leakage study suggests that the average California industry will experience an 11% decline in output if forced to fully absorb a \$22.62 carbon price.¹¹² Under a similar carbon price assumption, the international leakage study suggests that the average industry would experience an 18% decline in output.¹¹³

¹¹² Gray, Wayne et al., Resources for the Future, "Employment and Output Leakage under California's Cap-and-Trade Program" (May 2016), Table A1.

¹¹³ The international leakage study estimates industries' output response to a carbon price of \$10 per metric ton, while the domestic leakage study estimates the output response under a carbon price of \$22.62 per metric ton. We have adjusted the results of the international leakage study to allow an "apples-to-apples" comparison and to simulate the effects of a more realistic carbon price in the post-

These projections are alarming by almost any measure. Consistent with CARB's view that the domestic and international leakage estimates can be applied in an additive fashion, the studies effectively imply that a \$22.62 carbon price will result in a 29% output decline for the average California industry in the absence of allowance allocations.¹¹⁴ To put this result into perspective, U.S. industrial production tends to fall by roughly 5% per year during a "typical" recession and declined by as much as 18% per year during the Great Recession of 2008-09 (see Figure 1). Simply put, the results of the leakage studies predict that, absent high levels of leakage assistance across most industries, the cap-and-trade program could push California into an industrial recession on an unprecedented scale.

These projections are even more alarming for industries that are at a high risk of leakage, such as cement (see Box 1). For instance, the international leakage study estimates that, under a carbon price of \$10 per metric ton, the California cement industry's output will decline by 72% — a decline far greater than that experienced during the bursting of the housing bubble and the onset of the deep recession in the mid-2000s.¹¹⁵

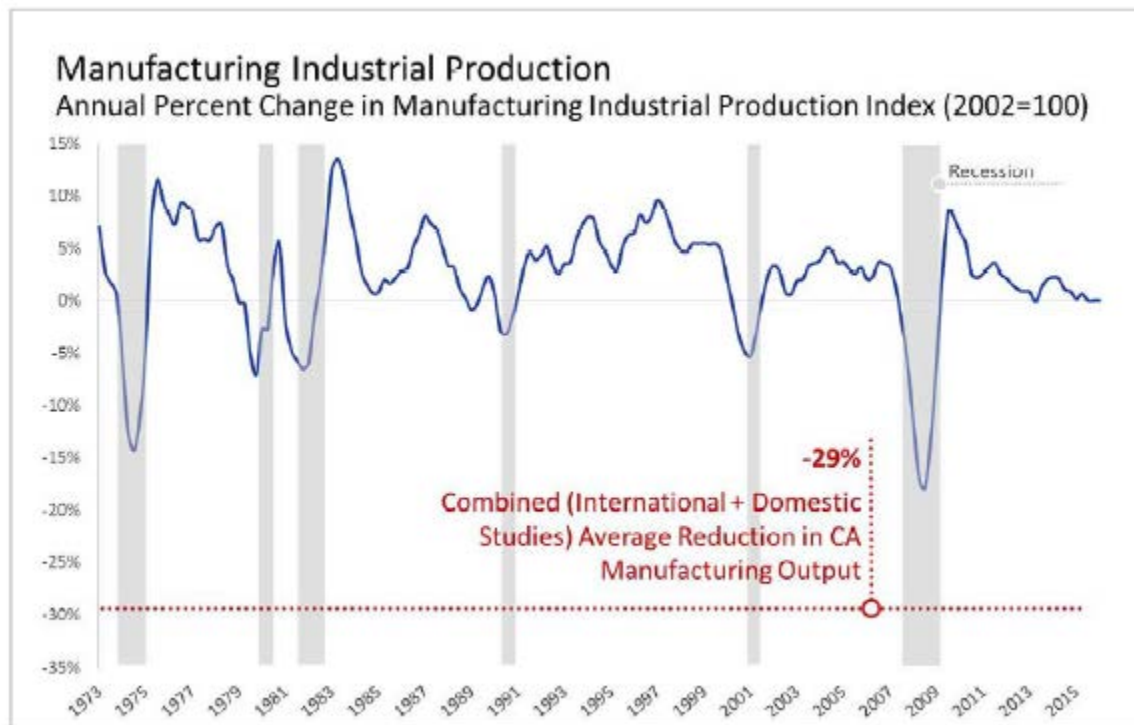
In addition to highlighting the importance of minimizing leakage through allowance allocations, the general thrust of the studies creates a dilemma for CARB. On the one hand, CARB has indicated that it intends to reduce allowance allocations for the industrial sector in the post-2020 timeframe. On the other hand, the results of the studies suggest that anything short of ample allowance allocations will result in a swift and severe recession in the manufacturing sector, and potentially the demise of high-risk industries, such as cement.

Figure 1. Historical Manufacturing Industrial Production

2020 timeframe. Specifically, the median output decline for each industry under a \$10 carbon price (see Table 10) was multiplied by a factor of 2.62 ($\$22.62 / \10.00), resulting in an average output decline of 18% across all industries. This adjustment assumes that there is an inverse linear relationship between the change in an industry's output and the magnitude of the carbon price, which is consistent with the assumptions used in the leakage studies.

¹¹⁴ These results are even more alarming given that they do not include the impact of process emissions and they are based on a carbon price assumption of \$22.62, which is consistent with the expected "price floor" post-2020.

¹¹⁵ Fowlie, M.L. et al., "Measuring Leakage Risk" (May 2016), ("International Leakage Study"), Table 11.



(CSCME)

Response: CSCME emphasizes the importance of emissions leakage prevention, as well as the implication of the studies for industry output in the absence of allowance allocation. CSCME expresses concern that substantial reductions in output and value added may be experienced by many sectors if GHG efficiency levels did not change and staff were to reduce allowance allocation.

ARB is directed by AB 32 to minimize leakage to the extent feasible. As CSCME states, the international and domestic studies provide evidence that, with no allowance allocation, the manufacturing sector would experience a drop in shipments in response to a GHG compliance obligation. This drop in the absence of any allowance allocation supports continued industrial assistance to combat emissions leakage, including in the post-2020 timeframe.

CSCME and other industrial stakeholders provided “extensive comments... expressing concerns both about the contracted leakage studies¹¹⁶ and staff’s proposed methodology¹¹⁷ for developing assistance factors using these studies.”¹¹⁸ While the studies provide support for the importance of allowance

¹¹⁶ These studies are described and included as references in Appendix E to the Initial Statement of Reasons for this rulemaking.

¹¹⁷ This methodology is outlined in Attachment B to the first 15-day notice for this rulemaking.

¹¹⁸ 2016 Rulemaking 2nd 15-day Notice, p8:

<https://www.arb.ca.gov/regact/2016/capandtrade16/2nd15daynot.pdf>

allocation, staff ultimately removed the post-2020 assistance factors proposed during the 2016 rulemaking. Following the close of the 2016 rulemaking, and in time for the first year of post-2020 allocation, staff will “initiate a deliberative process with input from industrial, environmental justice, environmental groups, and other interested stakeholders to establish a robust and transparent framework for establishing post-2020 assistance factors.”¹¹⁹ Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.7. Comment:

Comments on Staff’s Proposals Concerning Post-2020 Leakage Studies Performed by Resources For the Future and Fowlie et al.

As previously noted in our comments of June 10, 2016, CLFP wishes to aid and inform CARB policy regarding future GHG allowance allocations with the goal of minimizing the potential harm to the California economy, and food processors in particular, and to avoid simply shifting emissions to other jurisdictions.

CARB commissioned three leakage studies specifically to evaluate and potentially modify Assistance Factors (AF) for all industrial sectors. Two of these were broad-sector studies which analyzed both international emissions leakage (Fowlie Study) and domestic leakage (RFF Study). According to CARB staff these studies “complement each other to provide a *complete picture* of emissions leakage potential for most manufacturing sectors.” (Page 4, Appendix E, Staff Report: Initial Statement of Reasons, Emissions Leakage Analysis, August 2, 2016). (emphasis added)

However, CARB staff’s position regarding a “complete picture” does not reflect the position of most, if not all, the industrial sector subject to cap-and-trade compliance obligations. CLFP, along with other industrial sector participants, challenged some of the conclusions of both the Fowlie and RFF studies based on the initial presentation on May 18th. In addition, CLFP requested additional time to respond to the studies and asked that the studies undergo vetting or an independent review.

CLFP was disappointed by CARB’s refusal to grant additional time to review both the International and Domestic studies, the very leakage studies which CARB staff makes clear will be basis for the new AF metrics for post-2020 implementation. This came on top of limiting the official comment period to just three weeks (June 10, 2016), given that these were two major leakage studies over two years in the making. No reason was ever given as to why additional time was not considered. To CLFP knowledge, no one challenged the good-faith efforts of either of the studies attempts to estimate emissions

¹¹⁹ 2016 Rulemaking 2nd 15-day Notice, p9:
<https://www.arb.ca.gov/regact/2016/capandtrade16/2nd15daynot.pdf>

leakage. Stakeholders' remarks in the May 18th workshop did cite some specific conclusions in the studies, and in the authors' presentation, that seemed incongruous with common industry experience.

In an effort to emphasize the need for additional vetting, or at least to highlight the need for a peer review of the studies, CLFP engaged Armando Levy, a noted economist with The Brattle Group, to provide a professional input. CLFP will not reiterate the points made in its June 10, 2016 comments but only list the following conclusion from Dr. Levy:

1. Clarity should be provided on how CARB will address the error structure in the new leakage metrics.

- Many of the estimated coefficients in the studies are statistically insignificant, and in some cases the estimates are significant but with the wrong sign (i.e., positive effects of cost increases on the value of shipments, seemingly implying “negative leakage”).
- The international leakage study provides plots of values at the 25th and 75th quantiles from 192 separate regression models, but does not provide a sense of the error structure around these estimates.
- The domestic study fails to report confidence intervals around their leakage estimates for individual industries.
- The empirical approach taken in each paper introduces a vastly larger error structure which is entirely absent in the old metrics (energy intensity and trade exposure), and will require clarification on how this error structure will be handled in formulating policy on allowance allocations:
 - Are leakage estimates to be taken as zero when the estimated coefficient from that industry is significantly indistinguishable from zero?
 - And what is the prescribed confidence level for making this determination?
 - If a coefficient is large, but not significantly different from zero, how does CARB intend to use this estimated value, as opposed to a smaller, but highly significant coefficient?

2. How does CARB intend to use the Cal Poly study for determining allowance allocations to the food processing industry?

CARB allocated public funds to the Cal Poly study, which met its stated goal of measuring production leakage in four of the largest food processing industries in California. How do these estimated leakage results fit in with the new metrics proposed by CARB for making allowance allocations?

3. The Brattle Report indicates that changes in the total value of shipments is an unreliable proxy for leakage. (see 1.C., page 6, Brattle)

“The Brattle Group Report notes that the key unit of measurement for leakage is the quantity of reduced production in California that is offset one-to-one by increased production in unregulated regions. That is, leakage refers to changes in quantities produced. Both the domestic and international study estimate the effect of changes in energy prices on the total value of shipment (i.e., sales), which is the product of price times quantity in each market.

“It is well-established in economics that sales can rise or fall with a change in quantity produced depending on the elasticity of demand in the particular market. Specifically: (i) if demand is unit-elastic, a decrease in regional production results in no change in sales; (ii) if demand is inelastic, a decrease in production results in an *increase* in sales; and (iii) if demand is elastic, a decrease in production results in a *decrease* in sales.”

The Brattle Group Report found that use of sales (total value of shipments) as the outcome variable in both the Domestic and International studies to be an unreliable proxy for production and emissions leakage. Brattle believes the same estimated effect on the value of shipments can be associated with positive, negative, or zero leakage depending on the unobserved value of the demand elasticity in each industry.

Of the points listed by Dr. Levy, the second is by far the most significant. Neither the Fowlie Study nor the RFF Study looks to market demand in estimating potential leakage. While this does not necessarily invalidate either study, it does present additional problems of relevance when confronted with the factors impacting the food processing industry markets.

As noted in CLFP’s previous comments, the Brattle Report found that the new metrics being proposed are relatively imprecise. Moreover, the data and variables employed by both studies do not seem to be appropriate for obtaining estimates of the parameters necessary to measure market transfer and emissions leakages, especially when applied to the food processing industry.

Any analysis of leakages without consideration of markets is no analysis at all. Development of a 4th Compliance Period AF for food processors must include a thorough analysis of market demand given the uniqueness of the food processing industry. An attempt to shoehorn food processors into the current analysis as set forth in the Fowlie and RFF studies risks not only damaging the competitiveness of California’s food processing industry but runs the secondary risk of negatively impacting the local economies in which food processors operate.

In closing, CLFP reiterates the need for CARB to acknowledge the uniqueness of the food processing industry in California. The fact that the food processing industry accounts for only .4 percent of the total industrial GHG emissions in the state should not

be grounds for discounting or ignoring the impacts of the leakage risk to facilities subject to the cap-and-trade. (FOODPROCESSORS)

Response: CLFP argues that leakage risks should be considered in all sectors, including those comprising a relatively small share of total industrial emissions. This is consistent with ARB's mandate to minimize emissions leakage to the extent feasible. CLFP also advocates for greater use of the CalPoly study¹²⁰ in developing the food processing industry's post-2020 assistance factors. ARB accommodated CLFP's and other stakeholders' concerns regarding additional time to vet the studies by postponing establishment of post-2020 assistance factors until a subsequent rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.8. Comment:

CLFP Recommendations

There is much at stake with the path that CARB chooses based on these studies. The food processing industry in California generates nearly 200,000 jobs, \$25 billion in value added to the economy, and \$8.2 billion in state and local tax revenue. Tomato, cheese, snack food, and dehydrated vegetable processors are a large component of the industry and stand to incur substantial compliance costs in the future given the increase in emission reductions mandated under SB 32.

1. CARB should consider an additional study to augment the Fowlie and RFF studies in order to include market demand data specific to the food processing industry for use in the development of the new metrics for determining AFs in the 4th compliance period.

CLFP looks forward to continued dialogue on this topic and providing information about the impact of SB 32 on the California food processing industry. (FOODPROCESSORS)

Response: CLFP requests additional studies to analyze more food processor sectors in support of post-2020 AFs. CLFP also comments on the general value of the agricultural industry to California's employment, economy, and tax revenue. Staff agrees that the post-2020 AF methodology is important to ensure continued emissions leakage prevention, and will continue the dialogue on post-2020 assistance factors with CLFP and other stakeholders. Staff commissioned three studies to examine emissions leakage risk. After the current rulemaking concludes, staff plans to work with stakeholders to establish post-2020 assistance factors as part of a future rulemaking, and will conclude this before

¹²⁰ Hamilton, S., Ligon, E., Shafran, A., Villas-Boas, S. (2016) "Production and Emissions Leakage from California's Cap-and-Trade Program in Food Processing Industries: Case Study of Tomato, Sugar, Wet Corn and Cheese Markets"

the 2021 allocation is scheduled to occur. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Calculation of Assistance Factors

B-6.9. Comment:

4.4 CARB's Proposed Approach Represents a Misapplication of the Leakage Study Results

CARB's proposed approach not only assumes the conceptual, analytical, and practical flaws of the underlying leakage studies, but also amplifies and compounds them by misapplying the results of the studies to generate a single estimate of an industry's leakage risk.

First, CARB proposes to apply the studies in a manner that ignores the explicit warnings of the authors themselves. For instance, CARB proposes to use estimates of the so-called "International Transfer Rate" as a key factor in determining each industry's leakage risk, despite a series of clear statements by the authors that indicate that this is an inappropriate application of the results, including but not limited to:

"The natural next step...is to translate these responsiveness measures to corresponding measures of market transfer and associated emissions leakage. However, pushing on to this next step amounts to pushing up against the limits of available data." [emphasis added]

"A ratio of noisy numbers can be very noisy; our industry-specific estimates of market transfer rates are sensitive to changes in how the underlying estimating equations are specified." [emphasis added]

"Given the noisiness of these estimates, we cannot estimate the transfer rate for any given industry with any degree of confidence." [emphasis added]

By making the international market transfer rate a key element of its proposed approach and introducing "alternative" regressions that are themselves based on the same study estimates, CARB effectively ignores the authors' warnings and ensures that these admittedly "noisy" estimates will be applied to every given industry with every degree of confidence.

Second, CARB's proposed approach attempts to combine two measures that are "apples and oranges." This challenge arises because of CARB's choice to evaluate "domestic leakage" and "international leakage" independently of each other, despite the fact that their impacts are highly interrelated as a practical matter and their distinction is largely irrelevant as a policy matter. Nevertheless, due to the "two study" methodology,

CARB is left with the difficult task of transforming the results from one study so that they are comparable to the other study.

CARB attempts to resolve this issue by transforming the results of the domestic leakage study so that they are comparable to the results of the international leakage study, though it fails to execute this task on multiple fronts. For instance:

- CARB's proposed approach does not appear to account for the fact that the international leakage study assumes a \$10 carbon price while the domestic study assumes \$24.88.¹²¹
- CARB's proposed approach appears to apply the international market transfer rate, which is a per unit measure, to calculate leakage risk without taking into account the size of the output drop (e.g., a 50% transfer of a 50% output drop will result in significantly more leakage than a 50% transfer of a 10% output drop).
- CARB's proposed methodology calls for imposing a "cutoff domestic drop" for the domestic leakage estimates in an apparent attempt to simulate the effect of the international market transfer rate on the international leakage estimates, despite the fact that it has no sound analytical basis for estimating an appropriate cutoff for any given industry.

This attempt to artificially adjust the results of one study to be comparable to the results of another study results in a methodology that is overwrought with arbitrary choices and overburdened by unnecessary complexity.

4.5 CARB's Proposed Approach is Not "Inherently Conservative"

CARB repeatedly asserts in the ISOR that its proposed approach results in "inherently conservative" assessments of leakage risk.¹²² For instance, CARB asserts that its proposed approach makes "conservative assumptions" and uses a "conservative approach to translate the study findings into revised AFs" resulting in "maximum possible potential emissions leakage risk levels" and "allocation in excess of the amount needed to prevent potential leakage."¹²³ Despite CARB's assertions, its proposed approach is not inherently conservative. Although CARB goes to great lengths in the ISOR to highlight aspects of the analysis that are likely to overestimate leakage risk, it makes no discernable effort to balance this with a discussion of a number of aspects that are likely to underestimate leakage risk.

¹²¹ In the ISOR at E-12 CARB states that "The domestic study simulated increased electricity and natural gas prices for a marginal compliance cost of \$24.88 per MTCO₂e in 2016 dollars..." However, the domestic leakage study's authors state that their analysis assumes a \$22.62 carbon price (see Table A-1, p 51). We are unable to explain the discrepancy between CARB's reported price assumption and the price assumption documented in the domestic leakage study.

¹²² ISOR at E-8.

¹²³ ISOR at E-6.

First, given that the studies estimate economic leakage (as opposed to emissions leakage), CARB is implicitly assuming that the GHG footprint of imported products is identical to the GHG footprint of products produced in California. However, this implicit assumption is unlikely to be true for at least three reasons:

- The California industrial sector is already highly energy efficient, which means that (on average) California goods are likely to have a lower direct GHG footprint than imported goods.
- The California grid is one of the most GHG efficient in the world, which means that (on average) California goods are likely to have a lower indirect GHG footprint than imported goods.
- Many imported goods are shipped to the California market from distant locations, which increases their GHG footprint relative to those produced inside the state.

Simply put, there are multiple reasons to believe that (on balance) the total GHG footprint of an imported good is likely to be greater than if that good was produced inside the state. To the extent true, CARB's implicit assumption of identical GHG footprints would place a downward bias on the results.

Second, CARB's proposed approach is based on results from studies with inherently un-conservative, unrealistic allowance price assumptions. Specifically, the international leakage study assumes a \$10 per metric ton carbon price, which is unrealistic given that the allowance price floor was set at \$10 in 2012. On the other hand, the domestic leakage study assumes an allowance price of \$22.62 per metric ton, which is a slight improvement from \$10 but is likely to be below the price floor by 2025.¹²⁴ The assumption of an allowance price that is likely to be below the future price floor faced by regulated industries is fundamentally inconsistent with a conservative approach to estimating leakage risk or determining allowance allocations.

Third, CARB's adoption of the international market transfer rates, which only reflect imports and exports of the same product, essentially assumes that there is no inter-industry leakage (e.g., a shift in market share to imports of substitute products). To the extent that an industry competes with other products that serve a similar need, CARB's implicit assumption of no inter-industry leakage would place a downward bias on the results.

Finally, many of CARB's assertions about the conservative nature of the methodology revolve around the assumption that each unit of lost output in a California industry translates into a one-for-one increase in output outside the state. However, CARB proceeds to effectively "unwind" this conservatism by using the international market transfer rate (which attempts to measure the portion of the loss that is transferred internationally) as the foundation of its proposed approach and applying a "cut off" to the

¹²⁴ This assumes a 5% per year adjustment to the price floor, plus 2% average annual inflation.

domestic drop estimates (which is intended to simulate a similar effect). In fact, given that CARB has ignored the authors warnings about using the international market transfer rate and that it has no objective basis for selecting an appropriate “cut off” for the domestic drop estimates, it is conceivable that CARB could not only fully offset but also potentially invert whatever conservative bias might have been associated with the one-for-one transfer assumption that was initially used in the studies.

In short, CARB’s assertions that the proposed approach is conservative cannot be substantiated on the current record. In order to reach such a conclusion, one must conduct a systematic and balanced assessment to identify all of the aspects of the analysis that might bias the results upward or downward, and weigh those factors against each other to determine the most likely direction. There is no evidence in the ISOR that suggests that CARB conducted such an assessment and, given the implicit assumptions and methodological choices noted above, it is possible if not probable that the results for many industries will be biased in the downward direction...

4.8 CARB’s Summary Justification for the Proposed Approach is Unsubstantiated

CARB summarizes its AF development methodology as follows:

“Staff believes that the IMT and DD metrics more precisely identify leakage risk from the Cap-and-Trade Program compared to the previous metrics and provide solid footing for minimizing leakage due to the Program. Basing AFs on historical California, national, and international sector-specific economic decisions that are observable and verifiable is the best approach to quantifying leakage risk. Alternative methods such as simulation-only or computable general equilibrium models may give results that are driven by subjective and opaque formulations of theoretical market behavior. Application of the commissioned, statistically based emissions leakage studies to assign specific AFs would help provide appropriate emissions leakage prevention for each industry in a fair and consistent manner. Staff is proposing to take a conservative approach and would apply the new methodology such that the proposed AF values would be higher than the levels deemed to be necessary to prevent emissions leakage.”¹²⁵

As demonstrated in the sections above, CARB’ summary justifications are unsubstantiated and appear to be inaccurate based on the information, data, and analysis provided in this rulemaking. For instance,

- Although the new metrics may be “more precise” than the current metrics, the key question is whether they are more accurate. CARB offers no evidence regarding accuracy, which leaves stakeholders to wonder whether the new metrics are precisely right or precisely wrong. The authors of the international leakage study appeared to volunteer an answer when they noted that it is

¹²⁵ ISOR at 40 (underlining added).

“difficult to estimate leakage potential for any particular industry with any degree of precision.”¹²⁶

- Rather than providing “solid footing”, the proposed approach actually places the entire allowance allocation framework on unstable regulatory, legal, and policy grounds by relying exclusively on the results of conceptually flawed studies that lack transparency and applies the results in a way that outsources CARB’s regulatory responsibilities to unaccountable third parties.
- CARB’s proposed approach is based almost exclusively on the results of studies that utilize confidential data from the U.S. Census Bureau that, by its very nature, are not “observable and verifiable” by stakeholders — including CARB staff. In contrast, the current leakage assessment framework is based on transparent data that can be verified by stakeholders — including CARB staff, regulated entities, and other stakeholders.
- Despite CARB’s assertions that its proposed approach is less “opaque” than alternatives, its use of unverifiable data and an unnecessarily complex methodology results in a regulatory “black box” that is literally and figuratively inaccessible to all stakeholders. In contrast, the current leakage assessment methodology applies transparent data in a straightforward fashion to arrive at results that, according to both CARB staff and the study’s authors, are consistent with the results of the studies, suggesting that the current approach arrives at the same general set of conclusions in a more transparent, more accessible, less time consuming, and less resource-intensive manner.
- CARB’s proposed application of the study results is, in fact, highly “subjective” in that it is based on a series of vague and unsubstantiated decisions, including an undefined adjustment to account for process emissions and an arbitrary selection of a “cut off” for domestic drop.
- The studies do not provide a “fair and consistent” approach to leakage prevention, as certain factors that are known to be relevant indicators of leakage risk are implicitly or explicitly ignored by the methodology, including the presence of process emissions, differences in the GHG footprint of domestic and imported products, and the potential for inter-industry leakage. Consequently, the studies are unlikely to provide a “fair and consistent” approach when it comes to industries that are subject to those factors.
- Finally, despite CARB’s repeated assertions, its proposed approach is simply not “conservative.” Although the assumption that output losses are displaced by out-of-state output gains on a one-for-one basis is a conservative assumption, CARB’s subsequent use of the international market transfer rate and a domestic drop “cut off” is likely to eliminate whatever conservatism may have existed in the

¹²⁶ International Leakage Study at 7.

studies, and could actually have the opposite effect. Furthermore, CARB fails to provide a balanced accounting of potential biases and, in doing so, overlooks a number of implicit assumptions that would logically bias the results in a downward direction.

5.1 Accounting for Process Emissions

As an industry with a process emissions intensity of more than 50%, the cement industry supports CARB's commitment to "[c]ontinue to prevent emissions leakage in the most cost-effective manner through *appropriate* allowance allocation for the post-2020 program,"¹²⁷ and would like to emphasize the importance of fully accounting for process emissions in providing "appropriate" allowance allocations. Unfortunately, technical flaws in CARB's proposed approach, and in the studies on which its approach is based, fail to adequately account for process emissions.

For instance, because neither the international market transfer rate nor the domestic drop measure account for process emissions, CARB must make ex-post adjustments when applying the studies' results. In describing those necessary adjustments, CARB states that "for sectors that have...process emissions in addition to energy-related emissions, staff would use an adjustment to the sector's regression IMT"¹²⁸ and "for sectors with...process emissions – variables used to calculate the regressed value added and regressed output (i.e., in two of the four DD estimation methodologies) – would be adjusted upward *as appropriate* under the revised methodology."¹²⁹ Aside from these general statements about making upward adjustments "as appropriate", CARB does not provide any detail or propose any specific framework for how it will account for process emissions. In the absence of a more specific and rigorous methodology, the cement industry has no basis for commenting on whether CARB's ex-post adjustments for process emissions will be either appropriate or sufficient to prevent leakage.

For example, CARB does not explain why the adjustment for process emissions would be limited to the regressions and not be made to the underlying study data. Given that the studies' output metrics are used as left-hand variables in CARB's alternative estimate regressions, the methodologically superior approach would be to make the process emissions adjustment beforehand, rather than basing the regressions on flawed measures and making ad-hoc adjustments afterward. In the case of the domestic leakage study, this adjustment would be fairly straightforward: domestic drop estimates increase in a linear fashion with respect to price shocks, and there is no true distinction between fuel emissions and process emissions. As a result, the following formula can be used to scale up the domestic drop measures according to each industry's process emissions intensity:

¹²⁷ ISOR at ES-5 (emphasis added).

¹²⁸ ISOR at E-11.

¹²⁹ ISOR at E-17 (emphasis added).

$$DD_{Adj.} = \frac{DD}{1 - PE_{Ratio}}$$

Where,

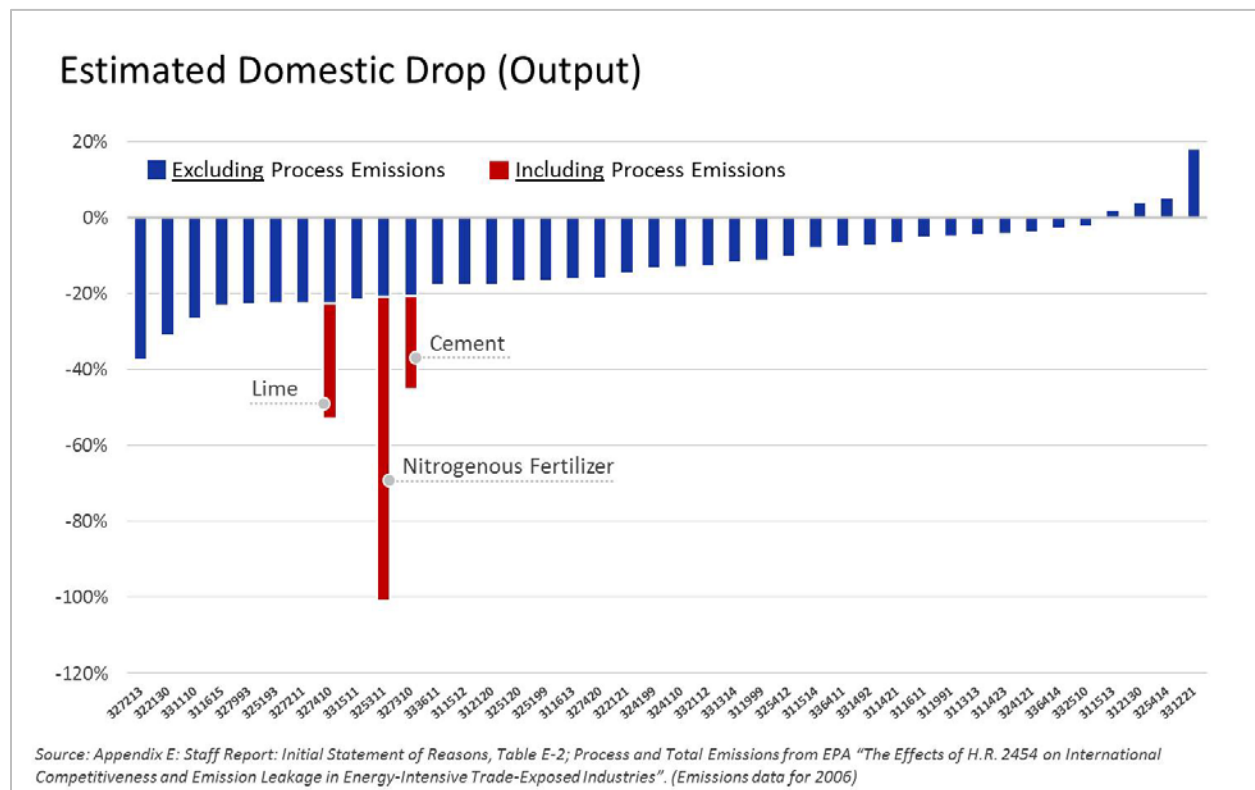
DD_{Adj} = The estimated domestic drop, adjusted for process emissions

DD = The estimated domestic drop, ignoring process emissions

PE_{Ratio} = The ratio of process emissions to total emissions

As shown in Figure 2, making this adjustment can result in dramatically different estimates of domestic drop for certain industries. For the cement industry, fully accounting for process emissions roughly doubles the estimated domestic drop in output associated with a carbon price.¹³⁰

Figure 2. Domestic Drop in Output, Process Emissions versus No Process Emissions



Regarding the international market transfer rate, CSCME is unable to comment on an appropriate adjustment to account for process emissions, as CARB has yet to make the rates public. Although the study does appear to make a post-hoc adjustment to the

¹³⁰ In a back-of-the-envelope calculation, CSCME used the industry emissions data included in EPA's analysis of the effects of H.R. 2454 (Waxman-Markey) on emissions leakage in energy-intensive trade-exposed industries. CARB could likely improve upon these estimates by using state-level industry data obtained through MRR submissions.

output response estimates to account for process emissions in some industries, it does not describe the data or methods used to make these adjustments.¹³¹ Therefore, CSCME is not able to evaluate that adjustment process and confirm that it accurately accounts for the impact of process emissions in the cement industry.

5.2 CARB's "Alternative" Estimates via Regression Analysis

Regarding its application of the domestic and international leakage studies, CARB's stated intention is to "ensure industries receive a minimum international [and domestic] AF component relative to key industry characteristics,"¹³² as a way of maintaining a "conservative approach" to allowance allocation such that "proposed AF values [will] be higher than the levels deemed to be necessary to prevent emissions leakage."¹³³ Although CSCME endorses CARB's intent, the approach that CARB has proposed for ensuring that a conservative degree of leakage assistance is provided to all industries contains significant conceptual and technical flaws.

From a conceptual perspective, CARB's regression approach uses the studies' international market transfer and domestic drop estimates as the left-hand variables, which means that this so-called "alternate" approach is really just a slight variant. Ultimately, the alternative approach is still fundamentally rooted in the results of non-transparent and unverifiable studies, whose assumptions do not apply to the cement industry and, as such, do not do enough to ensure that CARB's revised approach will be either conservative or appropriate.

From a technical perspective, CARB's inclusion of both emissions intensity and energy intensity as right-hand variables is difficult to justify. Given that emissions intensity is the more directly related metric to emissions leakage, energy intensity should only be used in the absence of reliable emissions intensity data. The inclusion of both metrics, without a clearly stated rationale, suggests that CARB has not carefully thought through the mechanics or logic of its alternate approach.

From a policy application perspective, CARB's regression approach will effectively result in alternative leakage estimates that reflect the industrial sector in general rather than the specific characteristics of individual industries. As a result, CARB will have spent several years and significant resources on studies that attempt to estimate response rates that are specific to individual industries, only to turn around and calculate "alternative" measures that reflect the average response across all industries.

Ultimately, CARB's proposed approach does not produce true "alternatives" to the results of the leakage studies. Rather, it amounts to a complex and unconstructive attempt to slightly modify the results of the studies based on the average response

¹³¹ International Leakage Study at Table 11.

¹³² ISOR at E-9.

¹³³ ISOR at 40.

across the entire industrial sector — thereby unwinding the researchers’ efforts to estimate industry-specific impacts.

5.3 Application of the Domestic Drop Cutoff

CARB’s decision to base its proposed framework for leakage assistance on two studies that were conducted independently of each other using distinct methodologies introduces several technical and implementation challenges. One of the most significant of these challenges is that, unlike the international leakage study’s international market transfer rate, the domestic drop measure does not calculate or assume a “transfer rate” on top of its estimated output response.¹³⁴ As a result, CARB cannot simply add the two measures together to create a “complete” leakage estimate for each industry without making an adjustment to one measure or the other.

According to CARB, “because of [the domestic study’s] one-for-one assumption, staff cannot simply translate the DD values...into the domestic AF component for each sector in the same way that the IMT values could be translated into the international AF component.”¹³⁵

CARB’s solution to this “apples and oranges” problem is to apply a “cutoff” rate to the domestic study’s domestic drop measures. Unfortunately, this post-hoc attempt to convert the domestic drop estimates into “IMT-like” measures is unsupported and misapplied:

Lack of Specificity. First, CARB’s description of its methodology for developing the domestic drop cutoff rate lacks specificity and leaves several important methodological questions unanswered. For instance, given the wide variation in market structure, capital-intensity, energy-intensity, and other characteristics across industries, will CARB set different cutoff rates for different industries, or apply a uniform rate? Similarly, if the cutoff rate will be industry-specific, what factors will CARB consider in setting sector-specific cutoff rates? The lack of specifics and transparency regarding this important element of CARB’s proposed approach raises significant concerns regarding whether the cutoff concept will treat the California industries fairly and appropriately.

¹³⁴ To be clear, we are not suggesting that the international market transfer rate is an appropriate measure of leakage risk in general or for the cement industry in particular. Indeed, as discussed in prior sections, there are a number of significant conceptual and technical flaws with the measure. Rather, we are merely pointing out that the measures from the two studies are not equivalent and cannot be combined unless one of them is transformed.

¹³⁵ ISOR at E-15. It does not appear as though CARB has fully considered that both studies provide estimates of the output effect from a carbon price, which (after adjusting for differences in carbon price assumptions) are directly comparable and provide a stronger basis for integrating the results of the two studies. By using the combined output effects as the basis for its leakage assessment, CARB would avoid the need to make arbitrary adjustments (e.g., selecting a domestic drop cutoff rate) and would apply results that are more likely to result in a truly conservative approach to allowance allocation (via the assumption that output losses are replaced by out-of-state production on a one-for-one basis).

Lack of Data. Not only has CARB failed to specify a methodology for developing the cutoff rate, it has also failed to provide the data that it will use to set the rate. Leaving aside the question of whether the proposed cutoff rate will be uniform or industry-specific, CARB's failure to specify the data that have been or will be used to set the rate leads CSCME to believe that the domestic drop cutoff will be arbitrary rather than based on quantitative evidence and rigorous analysis.

Misapplication. Finally, to the extent that CARB has elaborated on its methodology, its proposed application of the domestic drop cutoff is logically inconsistent with the domestic leakage study's methodology and key results. Specifically, the relationship between the study's domestic drop estimates and the level of leakage assistance provided is clearly linear.¹³⁶ However, despite the simple linear relationship presented in the study, CARB appears to apply a "stepwise" approach to determining industries' level of leakage assistance, ratcheting up the assistance level in fixed increments until the cutoff is exceeded.¹³⁷ Such an approach is clearly suboptimal relative to selecting the precise level of leakage assistance – to the decimal point – that would maximize the assistance provided relative to the cutoff threshold. In addition, charts in Appendix Figures E-3 and E-4 suggest that each additional increment of leakage assistance does not result in a constant or fixed reduction in an industry's domestic drop. Again, this implication is completely inconsistent with the domestic study's results, which posit a constant, linear relationship between domestic drop and the degree of leakage assistance. This misapplication of the domestic drop measure raises concerns that CARB does not fully consider the study's methodology or key results.

VI. Recommendations

CSCME recommends that CARB reevaluate its proposed approach, including whether to retain its existing framework, to ensure that its post-2020 allowance allocation framework is consistent with the guiding principles outlined above and is effective in minimizing the risk of leakage.

In the context of its proposed approach, we recommend that CARB:

Revise its regulatory process and timelines so that all stakeholders, including CARB staff, have sufficient opportunity to fully understand the strengths, weaknesses, and limitations of the leakage studies;

Release the information necessary for stakeholders to assess the data, methods, and results of the studies, including but not limited to data on international market transfer rates estimated by the international leakage study;

Engage stakeholders in a more robust conversation about measuring leakage risk, including but not limited to additional workshops in which stakeholders may ask

¹³⁶ ISOR at E-23, Table E-2.

¹³⁷ ISOR at E-9, Figures E-3 and E-4.

substantive technical questions about the studies to CARB staff and the authors of the studies; and

Consider analytical frameworks that do not rely on the results of the leakage studies as the sole determinative basis for measuring relative leakage risk but, instead, view them as one of several potentially useful data points for a framework that is consistent with the guiding principles outlined above. (CSCME)

Response: CSCME comments on the method used by staff to combine the outcomes of the two studies into a single AF estimate, that CSCME does not consider the method to be inherently conservative, the accuracy of the international market transfer as applied to a single industry, how process emissions are incorporated into leakage assessment, the theory underlying ARB's regression analysis of leakage study results, and the basis of cutoffs for domestic drops. CSCME makes requests regarding process, data release, and the basis of leakage assessment.

Staff has delayed implementation of a post-2020 AF framework in part to give an opportunity to replace or refine the emissions leakage prevention methodology proposed in the 2016 rulemaking's Appendix E¹³⁸ and Attachment B.¹³⁹ As noted in the second 15-day notice, staff intends to continue assessment of appropriate calculations of emissions leakage risk for the post-2020 period, and to propose post-2020 assistance factors in a future rulemaking. And, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program. ARB will continue to have limits on the data it can release, as discussed in responses to 45-day comments K-1.5 and M-1.13.

Regarding the international market transfer coefficient (international market transfer), CSCME quotes a section of the international study:

"The natural next step...is to translate these responsiveness measures to corresponding measures of market transfer and associated emissions leakage. However, pushing on to this next step amounts to pushing up against the limits of available data... A ratio of noisy numbers can be very noisy; our industry-specific estimates of market transfer rates are sensitive to changes in how the underlying estimating equations are

¹³⁸ Appendix E: Emissions Leakage Analysis:

<https://www.arb.ca.gov/regact/2016/capandtrade16/appe.pdf>

¹³⁹ Attachment B: Post-2020 Industry Assistance Factor Calculations

(<https://www.arb.ca.gov/regact/2016/capandtrade16/attachb.pdf>) and Post-2020 Assistance Factor Calculations Spreadsheet (<https://www.arb.ca.gov/regact/2016/capandtrade16/post-2020-af.xlsx>)

specified...Given the noisiness of these estimates, we cannot estimate the transfer rate for any given industry with any degree of confidence.”¹⁴⁰

Following the quote selected by CSCME, the researchers state “[they] can summarize general patterns in the [international market transfer] estimates,” that the estimates point to an industry-wide pattern of high transfer rates corresponding with those sectors designated as high leakage risk by ARB’s 2010 Appendix K leakage assessment. Use of the international market transfer, as well as other options, may be considered for use as part of a subsequent public process and rulemaking to develop post-2020 assistance factors. With respect to differentials in the GHG footprint of Californian versus out-of-State production, see staff’s response to the 1st 15-day comment B-6.4.

Industry-Specific Comments on Assistance Factors

B-6.10. Comment:

BOX 1. LEAKAGE RISK FACTORS IN THE CALIFORNIA CEMENT INDUSTRY: A PRIMER

As described in its March 2016 comment letter to CARB, the California cement industry is at an extreme risk of leakage in both absolute and relative terms.¹⁴¹ CARB has recognized the cement industry’s extreme risk of leakage in at least two critical respects. First, CARB classified cement in the “high leakage risk” category for the purpose of allocating allowances during the first three compliance periods. Second, CARB directed its staff to consider a border adjustment measure (“BAM”) for cement to address the additional risk of leakage associated with the existing allowance allocation approach.¹⁴²

The cement industry’s extreme leakage risk is based on a confluence of risk factors, including but not limited to:

- An extraordinarily high exposure to the compliance costs associated with a cap-and-trade program due to the industry’s high emissions intensity. In fact, according to CARB’s analysis that was used to support the current allowance allocation framework, the cement industry has a GHG intensity that is more than three times greater than that of the next most emissions-intensive industry.
- An exceptionally low ability to reduce its GHG intensity primarily because more than half of the industry’s GHG footprint is associated with process emissions,

¹⁴⁰ Fowlie, M.; Reguant, M., Ryan, S., “Measuring Leakage Risk,” May 2016, pp. 38-39, available at <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/ucb-intl-leakage.pdf>

¹⁴¹ See CSCME, “Comments Related to the Risk of Leakage in the Cement Sector” and Appendix, March 10, 2016, attached to CSCME, “Comments on May 18, 2016 Public Workshop on Emissions Leakage Potential Studies,” June 10, 2016, at Attachment 1.

¹⁴² CARB Resolution 10-42, December 16, 2010. Unfortunately, CARB has not developed a BAM to address the increasing risk of leakage to the California cement industry and is now proposing fundamental changes to the allowance allocation framework.

but also because existing plants already utilize the most advanced and energy efficient production technology and are constrained in their ability to substitute lower carbon fuels in the future due to market, technical, and regulatory barriers.

- A severely limited ability to pass through realized compliance costs to consumers without suffering a loss of market share or profitability due to the fact that cement is a commodity that competes almost exclusively on the basis of price; cement is a fungible product that is highly substitutable with imported supply; the California cement industry is a highly contestable market that is logistically and economically accessible to competitors throughout the Asia Pacific region; and the global cement industry is capital-intensive by nature and currently plagued by overcapacity, which gives international competitors both structural and cyclical motives to aggressively exploit the cost advantages that could materialize under the California cap-and-trade program.

This risk threatens to offset reductions of GHG emissions in the California cement industry with increases in GHG emissions outside of the state – thereby frustrating and undermining CARB’s ability to achieve California’s climate change objectives.

[The commenter attached the June 2016 comment letter to ARB, the March 2016 comment letter to ARB, and the appendix to the March letter that are referred to in the first sentence of the first paragraph of this comment and its footnote. These documents give further detail on some of the comments which the commenter has summarized in their current comment letter. The March letter cites Exhibits 1-12, which are included as attachments. These exhibits consist of a page from a Vivid Economics report on leakage risk in the EU ETS; excerpts from International Trade Commission (ITC) reports on cement imported from Japan, Mexico, and Venezuela; excerpts from Jamaican and Taiwanese anti-dumping investigations regarding cement; and ITC data on cement imports into California in 2000-2015.

The appendix, titled “Global Supply and Demand Conditions Elevate the Risk of Leakage in the Cement Sector,” goes into further detail on the points stated in the March letter. Its introduction, included immediately below, summarizes its main points:]

Global supply and demand conditions elevate the risk of leakage in the cement sector. There is significant excess cement capacity in foreign countries, particularly in China, and foreign producers are export oriented. The slowdown of the Chinese economy and significant government subsidies provided to Chinese cement producers indicate that excess capacity will remain high. Due to this excess capacity, foreign cement producers have the ability to significantly increase exports to California. In similar situations, significant global excess capacity in the aluminum and steel industries combined with slowing demand in key markets, particularly in China, have caused a surge in imports that are inflicting severe economic harm on U.S. industries. These factors pose a significant threat to the California cement industry and elevate the risk of leakage in this industry.

[The appendix cites Exhibits A-1 through A-26, which the commenter included as attachments. These exhibits consist of an excerpt from an EU Chamber of Commerce document on Chinese industrial production, cement companies, and EU responses; trade journal articles about Chinese cement demand, production and government targets, global prices, Japanese cement demand and production, Chinese aluminum, steel and oil production and global prices, steel energy use, Alcoa aluminum, EU Chamber of Commerce responses to Chinese industrial production, a U.S. customs and trade enforcement bill, and the US steel industry, including a statement from the China National Building Materials Group Corporation, some in English and some in Chinese with parts translated into English, presumably by the commenter; USGS 2013 Minerals Yearbook cement production and shipments data; a garbled news article about Vietnamese cement production and prices; China's Cement Industry "12th Five Year" Development Plan (2015 goals compared to 2010), in Chinese with excerpts translated into English, presumably by the commenter; cement industry plans from Shandong and Hubei provinces, in Chinese with excerpts translated into English, presumably by the commenter; excerpts from 2014 annual reports of Anhui Conch Cement Co., Ltd., Huaxin Cement Co., Ltd., Henan Tongli Cement Co., Ltd., Fujian Cement Inc., and Allied Cement Holdings Ltd., some in Chinese with parts translated into English, apparently by the commenter; and a U.S. Department of Commerce 2015 fact sheet on outcomes of the 26th U.S.-China Joint Commission on Commerce and Trade.

Some of the news articles state "Copyright CW Group. All rights reserved. Unauthorized distribution expressly prohibited.]" (CSCME)

Response: CSCME correctly identifies that the 2010 ISOR Appendix K framework designates the cement industry as having one of the highest emissions intensities of the covered industrial sectors that qualify for allowance allocation under the Cap-and-Trade Regulation (along with the lime sector).¹⁴³ CSCME also correctly states that its member cement sector covered facilities have significant process emissions that, in the absence of carbon sequestration, are a natural and unavoidable result of producing clinker, one of the key inputs to cement.

Under ARB's current allocation framework, these two features qualify the cement industry for a 100 percent AF and a reduced cap adjustment factor. As a result, the cement industry receives a high allowance allocation per unit of benchmark production from 2013 to 2020. ARB has extended establishment of a post-2020 allocation methodology to a subsequent rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

¹⁴³ 2010 ISOR Appendix K pK-15 "Table K-4: Proposed Emissions Intensity Classification"
<https://www.arb.ca.gov/regact/2010/capandtrade10/capv4appk.pdf>

B-6.11. Multiple Comments:

NAIMA participated in the public comment process when CARB initially established the Cap-and-Trade Program. NAIMA appreciated the extensive dialogue and exchange of information throughout that process. NAIMA found that CARB was responsive to NAIMA's concerns and comments and ultimately awarded 100 percent assistance factors in recognition of the evident risk to the Fiber Glass insulation industry of domestic leakage. The factual scenario and geographic configuration of manufacturing facilities at or near California's border remains essentially the same as it was in 2011 and 2012, so California's recognition of a domestic leakage risk for the Fiber Glass insulation industry remains fully justified.

II. CARB SHOULD APPROPRIATELY RECOGNIZE THE POTENTIAL DOMESTIC LEAKAGE RISK FOR THE FIBER GLASS INSULATION INDUSTRY, RETAIN 100 PERCENT ASSISTANCE FACTORS FOR THE THIRD PHASE, AND ASSIGN A 100 PERCENT ASSISTANCE FACTOR BEYOND 2020

A. The Fiber Glass Insulation Industry Has a Strong Presence In the State of California

The Proposed Amendments are particularly relevant to NAIMA and its members because NAIMA's members have four (4) manufacturing plants located in California:¹⁴⁴

- CertainTeed – Chowchilla, California
- Johns Manville – Willows, California
- Knauf Insulation – Shasta Lake, California
- Owens Corning – Santa Clara, California

In addition, virtually all of NAIMA's members' products are used or sold in California. More importantly, NAIMA's members provide important manufacturing jobs to the California economy. Specifically, Owens Corning operates a fiber glass building materials manufacturing facility in Santa Clara. According to public sources, Owens Corning's Santa Clara facility has an estimated 100 to 249 employees with an annual revenue of \$20 to \$50 million (www.manta.com/c/mmcontlv/owens-corning). Johns Manville operates a fiber glass manufacturing facility in Willows, California. According to public sources, Johns Manville's Willows facility employs between 250 and 499 employees and generates annual revenue of \$100 to \$500 million (www.manta.com/c/mmckkzn/johns-manville). CertainTeed Corporation operates a fiber glass manufacturing facility in Chowchilla, California. According to public sources, CertainTeed's Chowchilla facility employs between 250 and 499 employees and generates annual revenue of \$100 to \$500 million (www.manta.com/c/mmjhsbb/certain-teedcorp). Knauf Insulation operates a fiber glass manufacturing facility in Shasta Lake,

¹⁴⁴ UPF Corporation in Bakersfield is a maker of fiber glass filter media as well as thermal and acoustical aircraft and marine insulation. UPF operates a manufacturing plant in California. UPF is not currently a member of NAIMA.

California. According to public sources, Knauf's Shasta Lake facility employs between 100 and 249 employees and generates annual revenue of \$20 to \$50 million (www.manta.com/c/mm0tt3b/knauf-fiberglass).

California is losing manufacturing jobs – in both traditional and high-tech industries – to other states and nations. One of the key reasons for this exodus from California is the State's existing regulatory requirements and concerns about the future regulatory climate.¹⁴⁵ NAIMA's members have found California's regulatory environment to be challenging, time-consuming, complex, duplicative, and costly.

CARB's existing Cap-and-Trade Program and now its Proposed Amendments extending the Cap-and-Trade Program beyond 2020 with a specific proposal to ratchet down assistance factors while simultaneously lowering threshold limits is a perfect illustration of such costly regulation. As discussed in greater detail below, the Proposed Amendments afford the Fiber Glass insulation industry the much needed protection against domestic leakage. NAIMA strongly supports CARB's assignment of 100 percent assistance factors to the Fiber Glass insulation industry. This is prudent and wise because the California market could potentially be supplied with insulation products by manufacturing facilities in other bordering or nearby states, as well as Canada and Mexico, under the right market conditions.

With the inclusion of 100 percent assistance factors such a result is not likely to happen. As indicated above, fiber glass insulation is an important contributor to the California economy, through direct manufacturing, shipment of finished product to markets within California and other western states, and export of product to foreign markets. It also supports the insulation industry and installers, is a critical material for the construction industry, and a much-used material for do-it-yourself consumers. In addition, fiber glass insulation promotes energy efficiency, environmental preservation, and reduces pollutants, including greenhouse gases. Fiber glass is also the most thoroughly tested and researched insulation product on the market. It is the preferred product for more than 80 percent of the insulation market. Raising the cost of insulation products by raising the costs of doing business for fiber glass insulation manufacturers or by artificially reducing the supply of available insulating materials will reduce the ability of the State to meet its greenhouse gas emission reduction goals. If the cost to California insulation customers should rise, it would likely discourage insulation installation beyond code, particularly in the do-it-yourself market. The price increase could also occur as a result of increased transportation costs from out-of-state plants if regulations priced California products too high.

III. LOCATIONS OF NEARBY FIBER GLASS MANUFACTURING PLANTS SUPPORT CALIFORNIA'S DECISION TO ASSIGN 100 PERCENT ASSISTANCE FACTORS TO THE FIBER GLASS INSULATION INDUSTRY

¹⁴⁵ Ross C. Devol, Perry Wong, Armen Bedroussian, Candice Flor Hynek, and David Rice, "Manufacturing 2.0: A More Prosperous California," Milken Institute, June 2009, p. 9.

CARB's effort to stop leakage is really an attempt to ensure that emission reductions within the State of California are not offset by emission increases in other jurisdictions by reducing industry flight from California. The following information and facts support CARB's allocation of 100 percent assistance factors to the Fiber Glass industry: 1) there is a demonstrated ability for existing insulation manufacturing facilities located throughout North America to increase or maintain fiber glass insulation production if production in California is reduced; 2) there is a potential for increased transportation-related emissions because of insulation products being shipped into the State of California that were previously manufactured and distributed within the State; and 3) because the lowest emitting plants in the industry are located in California¹⁴⁶ and there is an absence of greenhouse gas regulations in other relevant jurisdictions outside California, transferring manufacturing to non-California jurisdictions would likely increase overall greenhouse gas emissions in the State and nation.

For the record, all California fiber glass manufacturers confirm that the vast majority of products presently produced in California that are used in California or are shipped out of California could potentially be supplied from other fiber glass manufacturing plants located within the U.S., Canada, and Mexico if the right market conditions prevailed such as high in-state production costs. As the cost to produce the product in California goes up, the economies of supplying the California market shift so that at some point it becomes more cost-efficient to import insulation products from out of state than to continue to supply the California market from the California facilities. This fact makes CARB's allocation of 100 percent allowances all the more important and vital to achieving CARB's emission reduction goals.

Since California plants are the best performers, it provides yet another incentive for CARB to keep fiber glass plants operating, without production reduction, in California. In fact, a production cost incentive to move more production to California facilities would have a positive impact on greenhouse gas reductions and California jobs.

Finally, while other North American manufacturers present the most immediate threat to California fiber glass manufacturing, Chinese imports, which have proven to be inferior in performance capacity and substandard in materials content, also present a significant threat to California's fiber glass insulation market and to overall greenhouse gas emission reductions.

A. The Evolution of CARB's Position On Leakage Risk For Fiber Glass Insulation

In CARB's original Cap-and-Trade proposal, fiber glass insulation (mineral wool) was assigned a medium level of leakage risk, which equated to a 100 percent assistance factor in 2012–2014; a 75 percent assistance factor in 2015–2017; and a 50 percent assistance factor in 2018–2020. The other two glass sectors (flat glass and glass packaging) received 100 percent allowances for all three compliance periods. CARB

¹⁴⁶ This statement is based on individual company's unique and specific knowledge of plant performance.

justified that distinction based on the lack of foreign competition for fiber glass insulation while recognizing that the other two glass sectors had strong foreign competition.

NAIMA responded that while there was a lack of foreign competition for fiber glass insulation, CARB's purpose for preventing leakage, nonetheless, was to stop businesses from fleeing the State;¹⁴⁷ it was equally plausible that leakage could occur within the United States. CARB had not conducted a domestic leakage analysis.¹⁴⁸ With the aid of a map showing all fiber glass and rock and slag wool manufacturing plants in North America, NAIMA was able to effectively demonstrate that, with two fiber glass manufacturing facilities at California's border in Arizona and two additional fiber glass plants in nearby Utah, domestic leakage was a far more immediate and realistic leakage threat than foreign leakage. NAIMA further demonstrated that the industry could easily transfer production eastward and easily maintain national production levels even with the closure of all California manufacturing plants.

In a meeting with Chair Mary Nichols, Chair Nichols informed NAIMA that CARB agreed with NAIMA and that 100 percent assistance factors would be assigned to the Fiber Glass insulation industry for all three compliance periods.

NAIMA is now facing new amendments to the Cap-and-Trade Program and an expansion to the Program beyond 2020. The facts that were so persuasive to Chair Nichols are still in place, and it is as equally important in 2016 as it was in 2012 for the Fiber Glass insulation industry (Mineral Wool Manufacturing) to be afforded 100 percent assistance factors for the final phase of the original Program and in 2020 and beyond. In fact, given CARB's goal of strengthening reductions, the facts are even more compelling now.

B. U.S. Domestic Insulation Production Still Presents A Genuine Leakage Threat For California

NAIMA respectfully requests CARB to recognize that if the California fiber glass operations are not economically viable as a result of AB 32 and the Proposed Amendments, some of NAIMA's California members might close their plants or significantly reduce capacity. The fiber glass insulation production capacity in other

¹⁴⁷ AB 32 mandates that CARB minimize leakage "to the extent feasible." See California Health and Safety Code § 38562(B)(8). CARB's technical appendices on leakage and allowance allocation seem to focus on international leakage (relocation of industry from California to other countries). But the statutory definition of leakage is not restricted to the international context; rather, it includes any situation where "a reduction in GHG emissions within the state [] is offset by an increase in GHG emissions outside the state." Cal. Health & Safety Code 38505(J). The main body of CARB's "Initial Statement of Reasons" (or "ISOR") for the Cap-and-Trade Program defines leakage in similar terms: "If production shifts outside of California to a region not subject to GHG emissions-reduction requirements, emissions could remain unchanged or even increase."

¹⁴⁸ During NAIMA's meeting, CARB acknowledged the limits of its analytical approach using only international leakage. In the context of trade exposure, for example, the Agency admits that its methodology "may not be sufficient to accurately quantify the degree of exposure to competition for many sectors." See ISOR App. K at page K-27.

jurisdictions will be able to adequately supply the California market, thereby increasing emissions in those jurisdictions and overall greenhouse gas concentrations, including in California. This fact is particularly relevant at the present moment because industry product resources are not fully utilized.

Any demand previously fulfilled by a California plant can be easily and economically supplied from other U.S. plants where production costs to change significantly. This industry does not have to look to offshore facilities to supply the California market. In addition to the increase in greenhouse gas emissions per ton of fiber glass insulation produced at these plants located outside California, the transportation needed to get that material to California markets would have a further negative impact on greenhouse gas emissions.

Aislantes Minerales, S.A. de C.V.
1. San Luis Potosi, Mexico

Armstrong Ceilings
2. Millwood, WV

CertainTeed Corp.
3. Athens, GA
4. Chowchilla, CA
5. Kansas City, KS
6. Ottawa, Ontario
7. Redcliff, Alberta
8. Sherman, TX
9. Tilsonburg, Ontario

Hollingsworth & Vose
10. Corvallis, OR

Industrial Insulation Group, LLC
11. Phenix City, AL

Johns Manville
12. Berlin, NJ
13. Cleburne, TX
14. Defiance, OH
15. Defiance, OH
16. Innisfail, Alberta
17. McPherson, KS
18. Richmond, IN
19. Waterville, OH
20. Willows, CA
21. Winder, GA

Knauf Insulation
22. Albion, MI
23. Inwood, WV
24. Kingman, AZ
25. Lanett, AL
26. Shasta Lake, CA
27. Shelbyville, IN
28. Wimsboro, SC

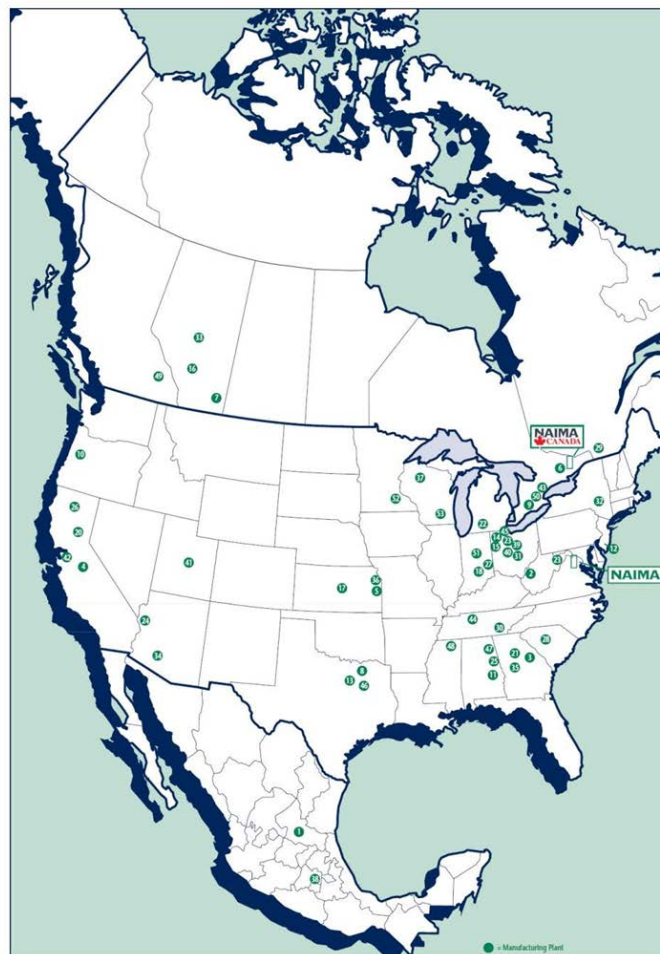
Owens Corning
29. Candiac, Quebec
30. Cleveland, TN
31. Columbus, OH
32. Delmar, NY
33. Edmonton, Alberta
34. Eloy, AZ
35. Fairburn, GA
36. Kansas City, KS
37. Ladysmith, WI
38. Mexico City, Mexico
39. Mount Vernon, OH
40. Newark, OH
41. Nephi, UT
42. Santa Clara, CA
43. Scarborough, Ontario
44. Springfield, TN
45. Tiffin, OH
46. Waxahachie, TX

Rock Wool Manufacturing Co.
47. Leeds, AL

Roxul Inc.
48. Byhalia, Mississippi
49. Grand Forks, British Columbia
50. Milton, Ontario

Thermafiber, Inc.
51. Wabash, IN

USG Interiors, LLC
52. Red Wing, MN
53. Watworth, WI



A close look at the map of fiber glass manufacturing capacity in North America effectively illustrates why fiber glass companies should be afforded 100 percent assistance factors for the third compliance period and all compliance periods beyond 2020. NAIMA again points out two manufacturing plants right at California's border in Arizona. Two additional plants in Utah also could relatively easily take up the work of

supplying the California market. There are also four insulation manufacturing plants in Western Canada.

The fiber glass insulation plants in the states bordering California are far more relevant to assessing the potential for leakage in this industry than 20 plants in Europe or 10 plants in Asia. If CARB is serious about preventing leakage from the State of California, it must carefully weigh the manufacturing potential, as illustrated on the above map of U.S. fiber glass and mineral wool insulation manufacturers. The presence of those 40-plus plants are the most effective argument for giving fiber glass plants 100 percent assistance factors for the third compliance period and beyond 2020.¹⁴⁹

The Fiber Glass insulation industry in California does face some competition from plants in Canada and Mexico. There have been some efforts by Chinese manufacturers to supply the U.S. market. However, the insulation produced was inferior to U.S.-produced product, and to date, China has not caught on as a source of supply for the U.S. market. A reduction of production in California could prompt a renewed effort on the part of Chinese manufacturers to supply this market. Aside from the economic impact of such a development, it could lead to even greater transportation-related greenhouse gas emissions in California and beyond.

C. Fiber Glass Companies Can Make Up For Production Reductions In California Plants

NAIMA has analyzed the fiber glass industry's capacity to compensate for the reduction in production or closure of 1 or more of California's fiber glass insulation manufacturing plants. Such reduction of production or plant closures could be likely triggered by the serious deleterious impacts from CARB's implementation of the proposed Cap-and-Trade Program.

First, to effectively assess the ability of North American fiber glass and mineral wool insulation manufacturers to satisfy any gap in the production of fiber glass insulation created by the closure of or reduction in output from California's fiber glass insulation plants, it is necessary to assess the current production of California manufacturing facilities.

The following chart identifies the number of production lines available at the California fiber glass facilities:

Company	Plant Locations	Number of Lines
CertainTeed	Chowchilla, CA	2
Johns Manville	Willows, CA	2
Knauf	Shasta Lake, CA	1
Owens Corning	Santa Clara, CA	2

¹⁴⁹ It is acknowledged that not all of these plants could produce the specific products being currently manufactured in the California plants.

The cumulative potential production capacity for the four California plants is estimated at 519,743 tons of fiber per year. The average utilization of this capacity in 2015 is estimated at 85 percent.

The CertainTeed, Johns Manville, Knauf, and Owens Corning facilities are producing residential and commercial insulation products that are used throughout the United States.

If any of the California plants were to reduce production or close due to the increased regulatory burden from the Proposed Amendments, fiber glass production facilities operating in the western part of North America could increase their production to serve the California market. These plants currently produce residential and commercial insulation products that are largely equivalent to those manufactured at California plants; there is no reason why they would not be able to serve the California market if production costs became too high in California. In addition, as the chart below demonstrates, these western U.S. plants have sufficient capacity to meet the demands of its current market plus demands west of its operation:

Company	Plant Locations	Number of Lines
CertainTeed	Redcliff, Alberta	1
Johns Manville	Innisfail, Alberta	3
Knauf	Kingman, AZ	1
Owens Corning	Eloy, AZ	1
Owens Corning	Nephi, UT	2
Owens Corning	Edmonton, Alberta	2

The cumulative potential production capacity of these western North American manufacturing plants is estimated at 352,840 tons of fiber per year. The average utilization of this capacity in 2015 is estimated at 58 percent.

Many of these western North American manufacturers are currently underutilized because of the residential and commercial building downturn; therefore, these plants have existing capacity to help meet the increased demand occasioned by the reduced production or closure of one or more California plants. In addition, consistent with the westward migration of products described above, any challenge to meet market demands from these western manufacturing facilities could be met by those manufacturing in the middle region of the United States and Mexico:

Company	Plant Locations	Number of Lines
CertainTeed	Kansas City, KS	4
Johns Manville	Cleburne, TX	3
Johns Manville	McPherson, KS	2
Johns Manville	Richmond, IN	2
Knauf	Albion, MI	4
Knauf	Shelbyville, IN	6

Owens Corning	Kansas City, KS	3
Owens Corning	Mexico City, Mexico	1
Owens Corning	Waxahachie, TX	3

The cumulative potential production capacity of these middle North American manufacturing plants is estimated at 1,235,878 tons of fiber per year. The average utilization of this capacity in 2015 is estimated at 88 percent.

As these charts demonstrate, the further east on the U.S. map, the greater the fiber glass insulation capacity. As illustrated above, the number of plants and the capacity of those plants are significantly greater. These simple geographic facts demonstrate that the current manufacturing capacity within the United States can, with a slight shift westward, accommodate the market demands created by the closure of three of the four California plants.

To further illustrate this point and bring it home, consider the chart below that lists the eastern manufacturing plants that also have the ability to meet any market demands created by the closure of California plants and the demand placed on plants in closer proximity to the California market:

Company	Plant Locations	Number of Lines
CertainTeed	Athens, GA	3
CertainTeed	Ottawa, Ontario	3
Johns Manville	Berlin, NJ	1
Johns Manville	Defiance, OH	13
Johns Manville	Winder, GA	2
Knauf	Inwood, WV	2
Knauf	Lanett, AL	3
Owens Corning	Delmar, NY	2
Owens Corning	Fairburn, GA	3
Owens Corning	Lakeland, FL	2
Owens Corning	Mount Vernon, OH	3
Owens Corning	Newark, OH	3
Owens Corning	Guelph, Ontario	2

The cumulative potential production capacity of these eastern North American plants is estimated at 1,094,938 tons of fiber per year. The average utilization of this capacity in 2015 is estimated at 77 percent.

The total cumulative capacity¹⁵⁰ for North America is estimated at 3,203,399 tons of fiber per year. A significant volume of capacity for mineral wool (rock and slag wool) insulation is not represented in this number. It is estimated that mineral wool has cumulative capacity for North America of 258,700 tons per year. The total utilization of this capacity in 2015 is estimated at 60 percent. The numbers speak for themselves, and it is plainly evident that any market gap caused by closure of California's plants could be quickly and easily satisfied by existing operations.

It is also worth noting that fiber glass insulation can readily be transported into California from other jurisdictions. Insulation can be shipped economically by truck or by rail (using intermodal trailers). It does not require any special infrastructure, and there are no hard and fast limits on shipping distances. In fact, some manufacturers have in the past and currently do ship products to Australia and Europe. Again, all out-of-state supplies, whether by rail, truck, or ship, would create additional transportation-related emissions in California and beyond.

The above series of charts tell a story of an industry and its ability to supply and meet the North American insulation market demands.

D. Domestic Leakage Analysis

The Brattle Group prepared an independent analysis of CARB's Domestic and International Leakage Studies. Key components of their analysis, as it relates to fiber glass production in California, are set forth below. The Brattle Group Report in its entirety is attached hereto and incorporated as part of NAIMA's comments.

"The RFF study examined 49 industries and used a mixture of industry and plant level data in California and other states to explore changes in output, employment, and value added resulting from energy price increases."¹⁵¹

"According to Table 2a, fiber glass manufacturing has the fourth highest electricity cost share (2.64%) of the 49 industries (average of 0.99%).¹⁵² Table 2a also reports the estimated elasticity of the manufacturing outcome measures with respect to electricity price. Elasticity measures the degree of responsiveness of one variable to a one percent change in another variable. According to Table 2a, a 1.0% increase in electricity price would cause a 1.42% drop in the output of fiber glass facilities

¹⁵⁰ Specific facilities that produce fibers for the production of ceiling tiles, fire proofing products, or specialized insulation production – for example, automotive, aerospace, and battery separators – are not included in this total capacity calculation. This capacity specifically relates to building insulation in residential, commercial, and industrial applications.

¹⁵¹ Output was measured as value of shipments, which is actually a dollar value and therefore affected by price as well as production quantity. This introduces a potential "identification" problem associated with the lack of an estimated elasticity of demand.

¹⁵² Electricity cost share is average share of electricity in value of shipments in 1989. As the authors explain, "[u]nder the standard assumption that in the long run, plants earn zero economic profits (i.e., accounting for opportunity costs), this share is equal to the cost share." (p. 9) In the text describing the results reported in Table 2a,

(measured by value of shipments), a 1.1% decline in employment and a 1.45% fall in value added (the value of shipments minus the cost of input materials). These adverse production results from electricity price increases are the second only to Automobile Manufacturing among the 49 industries studied.

“Like the Domestic Study, the econometric study of international leakage also shows the relative sensitivity of fiber glass manufacturing production to energy price increases. In Table 9, the fiber glass industry is the 11th most sensitive (out of 51 industries displayed and 98 industries studied) to energy prices as measured by the elasticity of production (50th percentile of coefficient values). Table 10 shows that the fiber glass industry would experience the 7th largest percentage production decline (out of 51 industries displayed) from a \$10/ton CO₂ price, assuming the 50th percentile value on coefficient estimates.

“Considered individually and together, the Domestic Study and the International Study indicate that fiber glass insulation manufacturing in California is very sensitive to energy price increases and thus prone to emissions leakage. Table 5 of the Domestic Study and Table 10 of the International Study show the output impacts of a \$10/ton CO₂ price. While fiber glass manufacturing (mineral wool) is the 6th and 7th most affected industry in the tables individually, only two industries are more affected according to *both* studies: paperboard mills (NAICS 322130) and iron and steel mills and ferroalloy (NAICS 331111). This underscores the high potential for emissions leakage arising from shifting fiber glass production outside of California as a result of CO₂ prices that affect production costs.”

[The commenter attached a study they commissioned from the Brattle Group, titled “Fiber Glass Insulation Manufacturing in California: A Case Study in Leakage Potential,” which goes into further detail on points which the commenter has summarized in their comments.] (NAIMA)

Comment:

I just wanted to raise a couple of issues to kind of highlight a couple of issues, first, on the assistance factor and the leakage for the first 2 compliance periods, and then, of course, for the 3.

Our industry was assigned 100 percent assistance factor based on a high leakage risk, primarily from domestic instead of international. We would certainly urge the Board to continue that post-2020. We're still at a high leakage risk, especially domestically, because there's still excess manufacturing capacity in the building insulation industry, because the housing market simply has not yet returned full. We do have, attached to the NAIMA comments, a separate report by the Brattle Group that analyzes the two leakage reports and does confirm that fiberglass insulation is still at a high leakage risk. (JOHNSMANV)

Response: NAIMA and Johns Manville emphasize that domestic leakage risk, as a result of significant national production capability in the fiberglass industry,

should be considered in establishing post-2020 assistance factors for the fiberglass industry. Staff agrees that domestic leakage risk is an important component of emissions leakage risk. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.12. Multiple Comments:

Our comments emphasize the importance of the current “high-risk” classification for the glass container manufacturing industry (NAICS 327213) and need for 100% industry assistance for the duration of the Cap and Trade program.

California’s glass container manufacturing industry has a well-established record as an Energy-Intensive-Trade-Exposed Industry (EITE). California glass container plants in particular compete with lesser-regulated glass plants across the country, in addition to international glass container production facilities.

We strongly disagree with the assertion made in the ISOR (page 39) that *“imports may decrease foreign production previously directed to serve international demand, rather than a one-for-one increase in foreign production.”* Glass container imports represent additional glass containers being manufactured in less regulated countries - directly offsetting and supplementing California glass container production. These containers would not be manufactured without the opportunity presented to offset California production.

As highlighted in the May 16, 2016 Final Report to CARB on Employment and Output Leakage under California’s Cap-and-Trade Program, *“an increase in California energy prices relative to prices in nearby regions will raise production costs in energy-intensive industries located in California and likely result in short-term (one year) losses in output, employment, and value added for those industries.”*

The Report (p. 16) clearly states that no EITE industry participant is impacted more by leakage than glass container manufacturing, who are anticipated to lose significantly in terms of output (17.10%) and jobs (13.31%). These losses will only be exacerbated by future increases in the cost of energy.

According to data collected by the US International Trade Commission (ITC) 2.1 billion additional containers were imported into the US in 2015, than in 2008. Nationally, imports of glass containers have increased 3-5% annually since 2008.

California and the broader US glass container industry have been competing with a consistent and significant increase of imported bottles and jars for food and beverages over the past several years. Analysis of 2015 glass container import data provided by the ITC found that on average, 28% of California glass customers purchased imported

containers. This is more than double the national average (13%) of imported glass container purchases by customers.

The majority of these imports are wine bottles, heading in through the West Coast ports, and competing directly with wine bottle manufacturing in California and similar plants in nearby states.

Sustaining and working to increase our already high levels of recycled glass use at our plants is the primary method of energy saving technology. For our industry, cullet usage represents additional “energy savings” at our plants. Due to the substitution of recycled glass for raw materials, the container glass manufacturers in California have been able to reduce their carbonate-based CO2 emissions to approximately 25% of the total CO2 emissions.

The high-risk classification, and continuing maximum industry assistance is critical to the future of California’s glass container manufacturing operations. It provides needed assistance and protects California glass plants from competitive advantages that similar plants in other countries and states currently enjoy.

Due to ongoing and future challenges (outlined above) to the California glass container industry, we request 100% industry assistance for the duration of the Cap and Trade program. (GLASSPACKAGING)

Comment:

I just wanted to briefly address the issue of transition assistance and leakage prevention for the container glass industry post-2020. As you probably know, the container glass industry is a very trade exposed industry. They are at a very high risk of leakage. The Board has always recognized this. Current regulations classify the container glass industry as a highly leakage risk industry. And as such, we enjoy 100 percent industry assistance factor for our industry.

We think that going forward that's very important, because as the Board's own assessment pointed out, the container glass industry among EITE industries is more -- is facing the largest impact of all the industries that were analyzed in the study.

We think that continuing 100 percent industry assistance factor going forward is a really easy way to mitigate some of the impacts that are discussed in this assessment to our industry, and in no way jeopardizes the integrity of the program and the greenhouse gas emission reduction goals of the State. (GLASSPACKAGING2)

Response: The Glass Packaging Institute (GPI) requests continuation of an 100 percent AF for the glass industry based on the domestic leakage paper’s findings of a large drop in domestic output and value added in a scenario under which ARB does not allocate allowances, recognition of recent trends of increased glass imports, and systematic differences in the fraction of imported versus domestic glass consumption in California versus the national average.

With respect to the findings of the domestic leakage paper, staff agrees that the domestic leakage paper provides important findings regarding domestic leakage. The paper's findings can help inform, or support, calculations of industrial assistance factors established pursuant to a future rulemaking to establish post-2020 assistance factors.

With respect to recent trends, ARB aims to incorporate recent data into establishing assistance factors to the extent that recent data improves on careful analysis of earlier time periods, and comes from reputable sources, and is available to staff in a timely manner. Staff draws a distinction between use of recent data on industry and forward extrapolation of industry trends. Staff has a strong preference against developing assistance factors based on extrapolation of industry trends, and instead has expressed an openness towards a future rulemaking should conditions experienced by covered facilities warrant a revisiting of assistance factor levels. Notwithstanding this, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

With respect to regional variation in trade exposure, in the notice to the second 15-day regulatory change proposal, staff committed to a public process with industrial and other stakeholders to establish post-2020 assistance factors.

B-6.13. Multiple Comments:

Comments on Staff's Proposals Concerning Leakage Risk

In 2011 and 2012, Board Resolutions 11-32 and 12-33 directed staff to investigate potential improvements to industrial allowance allocation to better meet the Assembly Bill 32 (AB 32) objective to minimize emissions leakage to the extent feasible. In response, ARB commissioned three emissions leakage potential studies to inform the development of assistance factors (AFs) for allowance allocation to manufacturing sectors.

The allowance allocation method that CARB devised at the onset of the cap-and-trade program included emissions intensity and trade exposure metrics which resulted in the food processing sector being designated as "medium" leakage risk. CLFP voiced objections to this classification scheme from the onset for the following reasons:

1. This method was, and remains, a very crude estimation technique unsupported by studies or other data;
2. The risk levels used to specify emissions intensity and trade exposure were based on gross measures of competitiveness, and arbitrary judgements about what constitutes high risk.

When CARB approved, in Resolution 11-32, a food processing industry leakage study, it was with knowledge of these inadequacies present in the previous study as well as it not being representative of the food processing industry in California. The initial study looked at only two processing plants, a California cheese manufacturer and a Georgia-based poultry plant, completely ignoring the fruit and vegetable processing operations located in the state. The data collected by CARB failed to note that many of California's food processors are seasonal, but also failed to take into account boilers sizes, differences in processing methods, and the international competitive pressures of the world markets. And there was no relevant market demand analysis or data at all.

Simply put, the purpose of the study approved in Resolution 11-32 was to acquire the data necessary to determine an accurate assistance factor/leakage risk for the food processing industry as the current leakage risk factors were not scientifically supported.

Per Resolution 11-32:

"BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-State competition of industries in California, and to recommend to the Board changes to the leakage risk determinations and allowance allocation approach, if needed, prior to the initial allocation of allowances for the first or second compliance period, as appropriate, for industries identified in Table 8-1 of the cap-and-trade regulation, including refineries and glass manufacturers...

"BE IT FURTHER RESOLVED that the Board directs the Executive Officer to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers, given domestic and international competition and continually fluctuating global markets. The Executive Officer shall identify and propose regulatory amendments, as appropriate." (Page 11) (emphasis added)

Any analysis of leakages without consideration of markets is no analysis at all. This need to understand our markets was intrinsic to the Resolution approved by the CARB Board in 2011. It is well recognized that very inelastic (price unresponsive) demand means that a large portion of the production cost increases can be passed downstream to consumers. However, in industries where California competes in international markets, such as dairy or tomatoes, demand facing California producers and processors is undoubtedly very elastic, meaning higher costs cannot be passed on and leakages will be very significant.

Yet, in the second paragraph of Appendix E, Staff Report: Initial Statement of Reasons (August 2, 2016) staff is seemingly attempting to alter the clear stated purpose for approving the leakage study:

"In commissioning the three studies, staff had intended to develop a revised methodology by which revised AFs, not including transition assistance, could be calculated and applied in the third compliance period (2018-2020). These revised AFs

would be at sector-specific levels necessary to minimize potential emissions leakage. After additional thought and discussion with stakeholders, staff decided to extend transition assistance through the third compliance period, at levels set in the 2013 regulatory amendments. Any revised AFs that may be proposed as part of 15-day comment period would be implemented starting in the fourth compliance period (post-2020).” (emphasis added)

What staff “intended” was never discussed with CLFP or any other food processing industry representative to CLFP’s knowledge, at least in regards to the food processing study. The impetus for the food processing study was the lack of data available to support CARB’s initial assignment of a medium leakage risk designation for the food processing industries and CLFP’s firm belief that CARB erred in the initial analysis. The Hamilton et al study was designed to provide accurate industry data for use in determining the leakage risk for the sector (NAICS §311) under the current Cap-and-Trade regulation. The study was specifically aimed at determining leakage risk for these sectors in 3rd compliance period.

As such, it would be patently unfair to allow such to be used as justification for a major policy decision that unilaterally denies a new leakage designation for food processors in the 3rd compliance period. What staff recommends compounds the original error in its decision by extending the transition assistance through the 3rd compliance period at levels set in 2013 without regard to the clear language in Resolution 11-32 and in light of the findings and conclusions of the Hamilton et. al study.

Food Processing Sector Study

It is irrefutable that most food processors in California compete with companies in other states and countries. California tomato processors compete with operations located in four other states and at least 18 other countries. Cheese is produced in virtually every state, and in numerous countries around the world, as well. Due to this level of competition, and the fact that food is generally not a luxury item, margins in the food processing business tend to be small. As a result, modest shifts in cost can affect market share, and CLFP believes that the Hamilton study, being sector specific, demonstrates that point.

CLFP has reviewed the Hamilton et al study and believes that the research team did a good job of quantifying market transfer rates and production leakage. The results demonstrate that, without free emissions allocations, the impact of even modest carbon prices on the processing sector would be significant and supports a continued high level of assistance for food processors in the 3rd compliance period.

The Hamilton et. al. Study was finalized in July 2015, months ahead of both the Fowlie and RFF Studies. However, CARB withheld the release of the food processing study pending the completion of the other two studies. All three studies were finally released May 2016. During that ten-month interim period, CLFP made two requests of CARB staff to release the study, either publicly or to CLFP for internal distribution to

participating companies. Both requests were rejected. In that ten months, CARB staff had ample opportunity to review and share its positions with the companies that participated in the study. Significant progress might have been made toward a more accurate leakage risk designation but for the delay in releasing the studies.

To date, CARB has yet to take a position regarding the Hamilton Study's conclusions as to high leakage risk for food processors. It should be noted that in light of the only sector specific study of the food processing industry's leakage risk, CARB has offer no factors to justify continuing the medium leakage risk in the 3rd compliance period. Nor has there been any position taken by CARB to refute the conclusions of the Hamilton et. al. Study. Lacking such, CLFP assumes that CARB has no general concerns with the findings.

As demonstrated by the Hamilton Study, even modest carbon prices can induce significant leakage to other states or countries. Having a reliable and stable supply of safe, high quality, and affordable food should be a public policy priority. That, along with the important economic impact that food processors have in communities across the state should be compelling reasons for CARB to designate food processors as high risk for leakage.

CLFP Recommendations

In conclusion CLFP makes the following recommendations:

Based on the Hamilton study, food processors should receive 100% allowance allocation or be designated a high leakage risk sector by CARB in the third compliance period. (FOODPROCESSORS)

Comment:

Emissions leakage for food and agriculture is Ag Council and AECA's central concern in this Regulation. Many food products do not go to market without further processing. Producing and processing food is mostly a seasonal activity, with operations lasting less than four months out of the year, with the exception of the dairy industry, where products are produced and processed throughout the year. Our industry is sensitive to import pressures from domestic competitors in other states as well as foreign competitors from countries such as China, Greece, Italy, South America and Mexico.

Many agricultural products are subject to trade exposure from low-cost competitors. Some of these markets can flood segments of our industry, such as the current situation in the canned peach industry. For example, the July 21, 2016 edition of "Peach Fuzz," a newsletter by the CA Canning Peach Association, demonstrates the problems associated with low-cost competitors.

California's canned peach imports for the 2015/16 marketing year reached a third consecutive all-time record high with 5,683,772 cases, up 9 percent from the previous record of 5,229,457 cases imported. China continues to be the leading importer with

3,046,046 cases shipped (54 percent of total volume). Unfortunately, the impact of this increased import volume is being felt in both the foodservice and retail market channels as this volume displaces domestic canned fruit sales. As an indication of the magnitude of canned peach imports in relation to domestic production, the 2015/16 canned peach imports amount to the equivalent of nearly 114,000 tons, which is 35 percent of California's peach crop this year.

This is just one example of a California food product being displaced by out-of-state suppliers. Another example of domestic pressure and competition is found in the dairy industry. California has experienced 20 consecutive months of milk production declines due in large part to higher production costs. Meanwhile, Wisconsin broke state milk production records in 2015 and has experienced 27 consecutive months of milk production increases. With this, it is becoming increasingly evident that the ongoing cost structure in California will adversely impact milk production. Processors could ultimately be unable to meet contractual commitments for both domestic and export opportunities and this has us very concerned.

The dairy sector has also been experiencing a decline in the number of dairy farms for several years. According to the California Department of Food and Agriculture (CDFA), 290 dairies have closed or left California since 2011, and 53 dairies have gone out of business in the first five months of 2016 alone.¹⁵³

Medium Leakage Risk Designation

Section 95870 – Disposition of Vintage 2013-2020 Allowances

Table 8-1: Assistance Factors by Industrial Activity for 2013-2020 (Page 153) This table shows that ARB staff is proposing NO CHANGES in industry assistance for food processing industry (NAICS code 311). Food Processing will remain a medium leakage risk for the third compliance period.

Under the existing allowance allocation methodology for the cap-and-trade program, ARB devised an emission intensity and trade exposure metric that resulted in the sector producing food being designated as “medium” leakage risk. For the first two compliance periods, companies producing food were granted a 100 percent Industry Assistance Factor. However, in the third compliance period (2018-2020) the allocated assistance will drop to 75 percent. To cover their compliance obligations, our member companies will have to purchase additional allowances. With low-cost competitors throughout the world, even a minimal increase in cost could displace certain market segments.

¹⁵³ https://www.cdfa.ca.gov/dairy/pdf/Annual/2011/2012_Annual_2011_Data.pdf (page 7) & <https://www.cdfa.ca.gov/dairy/pdf/Annual/2016/MidYear2016.pdf> (page 2)

This classification was based on a 2016 leakage analysis¹⁵⁴ of the food industry that was outdated, incomplete and incorrect on a number of issues. The leakage analysis only looked at four commodities produced in California, which is a fraction of the 400 commodities that are produced in the state. Additionally, the cheese portion of the analysis assumes federal programs are in place to support the industry.¹⁵⁵ These programs no longer exist. The Dairy Product Prices Support Program (DPPSP) ended on December 31, 2013. The Dairy Export Incentive Program ended on September 30, 2013 and was not used for approximately ten years prior.

The author also cites milk utilization data from 2001¹⁵⁶, when there is more recent data available from CDFA. Furthermore, the author states that imports are limited to 2-3 percent,¹⁵⁷ when in fact in times where there are disparities in international and U.S. prices, imports actually increase. The author also states that U.S. dairy is insulated from world market prices and foreign import trade,¹⁵⁸ however 15 percent of milk produced in the U.S. goes to export markets.

CDFA could provide additional information clarifying pressures from international markets. The study suggests that environmental costs could be mitigated through California's pricing system or "independent marketing system,"¹⁵⁹ but the program is not that simplified to easily offset all immediate costs bourn by the industry. The study also states, "The total cost to firms producing cheese ranges from \$50 - \$70 million a year, or 10-13 cents per pound of production."¹⁶⁰ These numbers are inaccurate. CDFA publishes actual cheese manufacturing costs every year that would be helpful in this piece of the study. Due to the major flaws in this report, it would be beneficial to have the author work more closely with CDFA to build a more accurate study of California dairy.

ARB has the authority to provide relief for industries like ours that are sensitive to trade exposure. However, we have not been granted 100 percent free allowances at this time. We hope that ARB will reevaluate its study on the industry and implement the Regulation in a way that more accurately portrays the international and domestic pressures on the California agricultural sector.

Recommendation: The food product sector should be moved to the top Industry Assistance Factor tier of "high" and receive 100 percent free allowances due to price pressures from domestic and international markets. Given the previous examples of the peach industry import pressures, coupled with the already existing problems of

¹⁵⁴ Hamilton, S. F., Ligon, E., Shafran, A., Villas-Boas, S. (2016). Production and Emissions Leakage from California's Cap- and-Trade Program in Food Processing Industries: Case Study of Tomato, Sugar, Wet Corn and Cheese Markets. Orfalea College of Business, Cal Poly San Luis Obispo.

¹⁵⁵ Hamilton et. al. (2016). Leakage, Page 13.

¹⁵⁶ Hamilton et. al. (2016). Leakage, Page 12.

¹⁵⁷ Hamilton et. al. (2016). Leakage, Page 13.

¹⁵⁸ Hamilton et. al. (2016). Leakage, Page 13.

¹⁵⁹ Hamilton et. al. (2016). Leakage, Page 13.

¹⁶⁰ Hamilton et. al. (2016). Leakage, Page 13.

California dairies leaving the state, leakage has already been demonstrated within California agriculture due to the competitive disadvantages we are experiencing in our current regulatory environment. This impending Regulation is bound to exacerbate this issue, as we are the only state in the nation with this law. (AGCOUNCIL)

Comment:

Emission leakage of food processors is our central concern. Agricultural products are sensitive to trade exposure from low-cost competitors in domestic and international markets. For example, U.S. canned peach exports for 2015 and '16 fell by 42 percent, which amounts to the industry's lowest export sales volume since 2002. Meanwhile, canned peach imports for 2015-16 marketing year reached a third consecutive all-time record high up 9 percent from the previous year.

China continues to be the leading importer with 54 percent of the total volume, while imports from Greece have increased 57 percent over the previous year.

California has also experienced 20 consecutive months of milk production declines due in large part to the high production costs. Meanwhile, Wisconsin broke state production records in 2015, and has experienced 27 consecutive months of production increases.

With this, it is becoming increasingly evident that the ongoing cost structure in California will adversely impact milk production, and processors may ultimately be unable to meet contractual commitments.

This has us very concerned. And despite the market realities, in the third compliance period of this program, staff is proposing to keep food processors in the median leakage category. To meet lower compliance obligations, our member companies will have to purchase additional allowances. A leakage analysis of the food processing sector showed that many food markets – showed that in many food markets price increases cannot simply be shifted onto consumers, so even minimal increases will displace markets for food product subject to this regulation.

The study came to this conclusion notwithstanding that it had a number of issues including outdated information on agricultural programs. We hope that ARB will reevaluate its current position and work with us to assign food processors to high leakage. (AGCOUNCIL2)

Response: Ag Council requests that the Hamilton study undergo substantial revisions and updates, including expanding the analysis to a number of additional commodities and incorporating institutional details in the dairy sector. The Hamilton analysis looked at four sectors because these are the only sectors that would provide data to the Hamilton researchers. Staff worked closely with Ag Council, CLFP, and the processing industry to complete these studies, and all covered food processing sectors (notably, there are no covered entities that produce peaches) had the opportunity and funding to expand the scope of the study, but declined to provide data for analysis by the researchers.

CLFP asserts that staff delayed the release of the Hamilton paper to the point where an opportunity was lost for staff and the Hamilton researchers to iterate further on additional refinement of processor-specific leakage assessments. Staff delayed the public release of the Hamilton paper until all the leakages studies were ready for publication because it would have been inappropriate for market-sensitive (in this case, potential future allocation) information about four sectors to have been released in advance of market-sensitive information about all other industrial sectors. ARB is careful to release information which has any bearing on the market in a manner that provides all market participants simultaneous access (as opposed to certain participants receiving information before others) to ensure a well-functioning market.

Staff is concerned that Ag Council calls the Hamilton study “outdated, incomplete and incorrect,” whereas CLFP wants ARB to rely upon it solely for assistance factor determination. CLFP and Ag Council request that the 2018-2020 assistance factors for the food processing sectors be set to 100 percent. See staff’s response to 45-day comment B-6.3 that specifically addresses this request by CLFP.

B-6.14. Comment:

We believe that the current Cap-and-Trade assistance factor of “medium” assigned to the ethanol manufacturing industry does not accurately reflect this existing level of competition, and the corresponding likelihood for small production price increases to drive ethanol production out-of-state.

This determination may have been the result of a failure to recognize that information regarding state-level imports of ethanol is readily available. We note that the discussion of Trade Data in Appendix K of the 2010 rulemaking, beginning at K-20, states that national imports and exports for all US ports will be used for the specific reason that “[s]tate level import data do not exist.” This statement may be true for other industry segments, but not for ethanol manufacturing. California imports over 80% of its ethanol from out-of-state. Therefore, if the state-level ethanol data were used, it would have resulted in a higher trade exposure metric and a corresponding higher initial leakage risk classification for the ethanol manufacturing industry.

The recent ARB leakage studies appear to recognize this inequity, but it is difficult to tell how the studies will translate into actual assistance factor values, and ARB has not yet proposed any revised assistance factors. ARB’s decision not to revise the third compliance period assistance factors could harm ethanol manufacturers, because the current leakage risk assigned to the industry is too low and does not accurately reflect the level of out-of-state market competition. (ETHANOL)

Response: The ethanol industry asks why regional data was not used in evaluating trade exposure in the ethanol industry. The ethanol industry also requests staff revise the 2018 to 2020 assistance factor upward for the ethanol industry. See

staff's responses to the 45-day comments B-6.1 for the justification, rationale, and previous accommodations to industry, in reducing 2018 to 2020 assistance factors for medium and low leakage risk sectors as designated by the 2010 ISOR Appendix K methodology. With respect to ethanol manufacturer's comment that State-specific trade data exists for the ethanol industry, staff notes that the commenter cited our 2010 analysis and methodology, not our most recent analyses of leakage risk.

The ethyl alcohol industry was added to Table 8-1 during the 2013 rulemaking after the 2010 methodology had been finalized. The 2013 rulemaking did not open re-classification of sectors through creation of a revised methodology selectively applied to new sectors (e.g., a methodology that could have used regional information). In light of the three leakages studies anticipated to be conducted as part of a future rulemaking (i.e., the current amendment process), staff did not contemplate creating a new regional methodology in past rulemakings, or in this current rulemaking. As such, it is out of scope of the current rulemaking as well.

B-6.15. Comment:

Emission and Investment Leakage Analysis - Solar remains concerned that we remain designated as a medium leakage risk. This designation will reduce our assistance factor by 25%. ARB Staff has not provided any information that substantiates the leakage analysis methodology is applicable to a single entity. Staff has also indicated that there will not be any changes for the 3rd compliance period, so that companies can plan accordingly. This is not the detailed reasoning industry was looking for when the Board directed Staff to revisit their leakage analysis in Resolutions 11-32 and 12-33. Staff should provide specific reasons and methodology for Solar's 3rd compliance period leakage designation ...

Post 2020 Industry Assistance Factors - The recommended regulatory changes do not include any proposed allocation assistance for Solar Turbines. ARB Staff would not provide any details to Solar about what may be proposed at a later date. Solar and other California businesses remain trade exposed, particularly given that no western states have joined the AB32 program, or enacted equivalent regulations on manufacturing. Solar has reduced our carbon footprint by 21% since 2006, and is committed to making more progress. However, assistance is still necessary, particularly for trade exposed companies like Solar that compete in international markets, to free up capital for plant investments. Solar requests that the Board direct staff to provide Solar with a post 2020 assistance factor of 100%. Additionally, any entity-specific allowances remaining from the previous compliance periods should be available for use in post 2020. (SOLARTURBINES)

Response: Solar Turbines requests an extension of its sector's 100 percent assistance factor for 2018 and beyond. It requests the specific reasons and methodology for their third compliance period leakage designation. 45-day comment B-6.1 provides staff's response on the reasoning and justification for reducing

through to 2020 assistance factors to 75 percent for medium leakage risk sectors, as well as the adjustments made to the originally-proposed 2018-2020 assistance factors made in the 2013 rulemaking. Staff's response to 45-day comment B-6.1 also explains the methodology by which sectors were classified into high, medium, and low leakage risk, as well as the intent for doing so.

Staff has postponed development of a post-2020 AF framework and sector-specific post-2020 assistance factors until a subsequent rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Miscellaneous

B-6.16. Comment:

II. GUIDING PRINCIPLES FOR ALLOWANCE ALLOCATION

Given its importance to the sustainability of California's cement industry and California's overall climate change program, CARB's allowance allocation framework must be designed in a careful, deliberate, and thoughtful fashion. CSCME believes that any allowance allocation framework to minimize leakage must uphold at least eight fundamental principles:

- Transparency: The framework should be based on verifiable data and methods so that stakeholders can confirm the accuracy of inputs and calculations.
- Accountability: The framework should, at a minimum, be based on data and analysis that can be fully verified and vetted by CARB so that the agency is accountable for its regulatory responsibilities.
- Accessibility: The framework should be as simple as possible and avoid unnecessary complexity so that stakeholders understand the basis on which they are being regulated.
- Compatibility: The framework should be easily adaptable by and integrated into other cap-and-trade programs so that CARB successfully achieves its goal of creating a broader, deeper, and more integrated carbon market.
- Applicability: The framework should allocate allowances in a manner that recognizes the applicable characteristics of individual industries.
- Equity: The framework should allocate allowances to industries according to relative leakage risk.

- Predictability: The framework should reduce policy uncertainty so that investors have clear “rules of the road” and can make long-term investments with confidence.
- Durability: The framework should be defensible against legal challenges and sustainable across multiple political and policy cycles.

CSCME believes that CARB’s proposed approach, as described in Appendix E of the ISOR, is inconsistent with all of these principles. Specifically, as demonstrated in the following sections, the approach:

- Relies on opaque data sources and inadequate oversight controls that violate basic principles of good governance, especially transparency and accountability.
- Embraces unnecessarily complex methods that render it inaccessible to the vast majority of stakeholders and virtually ensures that it will be incompatible with other cap-and-trade programs.
- Fails to adequately recognize the applicable characteristics of certain industries, including cement, and, therefore, is unlikely to result in allocating allowances in proportion to leakage risk.
- Reflects a rulemaking process that is likely to generate additional policy uncertainty and create legal and political vulnerabilities that will threaten the long-term viability of the allowance allocation system, the cap-and-trade program, and California’s overall efforts to reduce GHG emissions.

(CSCME)

Response: CSCME and other sectors provided comments expressing concerns about the leakage studies and staff’s methodology for developing assistance factors. In response, staff postponed establishment of post-2020 assistance factors until a future rulemaking that will occur in advance of post-2020 allocation. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.17. Comment:

1) ARB’s “Emissions Leakage Analysis” in Appendix E to the rulemaking Staff Report does not provide much useful information regarding leakage factors for particular industry groups because it is just an outline that explains how ARB will calculate leakage risk for the post-2020 Cap-and-Trade rule. ARB is now proposing not to change the 2018-2020 assistance factors, even though ARB originally proposed to do so. Any post-2020 assistance factors will be proposed at a later date and will be implemented with a shortened 15-day notice and comment period.

The problem with this approach is that any industries currently categorized as “low” or “medium” leakage risk which should have been a “high” leakage risk based on ARB’s recent leakage studies could get fewer than necessary allowance allocations in the 2018-2020 third compliance period.

2) Appendix E introduces the concept that the assistance factor (AF) in the Cap-and-Trade Regulation is composed of two elements, “transition assistance” and “leakage protection,” but this concept was not discussed in 2010 and 2013 when ARB performed its previous leakage analyses. ARB states that the three leakage studies it just completed are meant to only identify “leakage protection” values. ARB does not believe there is a need for “transition assistance” any longer.

Again, the problem with ARB’s approach to this rule amendment is that “high” leakage risk industries identified in ARB’s recent leakage studies could have “leakage protection” values greater than the current third compliance period assistance factors of 50% (low risk) or 75% (medium risk). Consequently, these industries could receive fewer than necessary allowance allocations in the third compliance period resulting in a competitive disadvantage for these California businesses and unintended GHG emissions leakage.

3) The ethanol manufacturing industry currently faces significant out-of-state domestic competition, and, therefore, the costs of the Cap-and-Trade Regulation have a significant impact on the competitiveness of California ethanol producers with this existing, well-developed out-of-state market. We believe that the current Cap-and-Trade assistance factor of “medium” assigned to the ethanol manufacturing industry does not accurately reflect this existing level of competition, and the corresponding likelihood for small production price increases to drive ethanol production out-of-state...

We request that the staff reconsider its determination not to revise the third compliance period leakage assistance factors, and review all industries that may have been previously categorized at a leakage assistance factor that was too low based on the recent ARB Members of the Air Resources Board leakage studies. Any industries with lower leakage assistance factors than those justified by the recent leakage studies should have their leakage assistance factors revised upward for the third compliance period. (ETHANOL)

Response: The ethanol manufacturers request an extension of medium and low leakage risk sectors’ assistance factors at 100 percent in case a future rulemaking determines a 100 percent AF is justified for some of these sectors. Staff refers the ethanol manufacturers to staff’s response to 45-day comment B-6.1 for a discussion of the rationale for leaving 2018-2020 assistance factors unchanged.

In response to concerns from stakeholders, ARB has postponed establishment of a new emissions leakage prevention methodology until a subsequent rulemaking that will be completed by fall 2020 in time for vintage 2021 allocation.

B-6.18. Comment:

Changes anticipated to the post-2020 Assistance Factors for industrial allocations will be proposed under a 15-day comment period.

Air Products feels this rulemaking process will not provide adequate time for impacted entities to fully assess the basis for the proposed change and develop a comprehensive response for agency consideration. Such changes may have a material financial impact and deserve adequate time to be reviewed and provide comments on.

Revision to the Assistance Factors for industrial allocations expects to eliminate the “transition assistance” portion beginning in 2021 while retaining the “leakage assistance” portion.

Air Products cannot effectively assess the impact of this proposed change in Assistance Factors, since the “transition assistance” portion of the current Assistance Factor for our sector has not been clearly differentiated from the overall factor. ARB should provide more background data before making such a change. (AIRPRODUCTS)

Response: Transition assistance is the difference between the 2013–2014 assistance factors and the 2018–2020 assistance factors, as defined in the 2010 Regulation.

B-6.19. Comment:

At Graphic Packaging International, we applaud ARB for continuing to address leakage issues for energy-intensive, trade-exposed entities like our Santa Clara Mill. (GRAPHICPACKAGING)

Response: Thank you for the support.

B-6.20. Multiple Comments:

In the current regulations, we do believe that trade protection -- trade exposure protection is necessary. And we encourage the Air Board to extend the industry assistance factor for future compliance periods. (CALCHAMBER2)

Comment:**“Expanded” Definition of Leakage**

According to the Initial Statement of Reason (ISOR), emissions leakage occurs when a program-caused decrease in emissions in California results in a corresponding program-caused increase in out-of-state emissions. The program-caused increase in out-of-state emissions is a necessary condition for emissions leakage. A drop in California emissions and/or economic activity alone is not a sufficient condition for, nor sufficient evidence of, emission leakage.

California agriculture is already experiencing leakage in many of its commodities. We agree with ARB when it admits that the climate change regulation is likely to cause

additional leakage and are pleased that it is attempting to mitigate the issue. We wish other state agencies would employ the same practice. However, it is admittedly difficult to determine exactly which regulation is causing leakage and it is likely that the entire complex regulatory environment in California is causing leakage. However, ARB needs to continue to recognize its role in leakage. This is underscored by the fact that ARB has invested so much in various leakage analyses.

Recommendation: One size does not fit all. We urge ARB to create a flexible enough definition (or understanding) of leakage so that it can be responsive to the various types of pressures that industries can experience as being the only state in the nation to embark upon an economy-wide cap-and-trade program. (AGCOUNCIL)

Response: Staff has a mandate to minimize emissions leakage to the extent feasible, which AB 32 defines as “a reduction in emissions of [GHGs] within the state that is offset by an increase in emissions of [GHGs] outside the state.” (Health & Safety Code, § 38505(j).) Emissions leakage is distinct from trade protection. Trade protection would enact barriers or compensate for costs and policies unrelated to the Cap-and-Trade Regulation in order to maintain profit and revenue. ARB staff declines to extend the emissions leakage mandate by compensating covered facilities or enacting trade protection in response to trade pressures or policies unrelated to the Cap-and-Trade Program.

ARB continually monitors for emissions leakage, and is open to rulemakings considering adjustments to emissions leakage prevention as warranted by data, including industry-supplied data on the specific pressures industry faces.

B-6.21. Multiple Comments:

Reduce giveaway of permits to industry: The fear of “leakage” has led to the program’s subsidies to the fossil fuel industry, which receives millions of permits for free (even though they mostly oppose the program). The Petroleum Refining, Natural Gas Extraction, and Cement sectors received over 49 million free allowances in 2016. At \$12.73 per allowance, that subsidy is worth over \$629 million per year. Reducing or eliminating this subsidy would help bolster demand which has been lagging in recent permit auctions. (SANDLER)

Comment:

The Petroleum Refining, Natural Gas Extraction, and Cement sectors received over 49 million free allowances in 2016. At \$12.73 per allowance, that subsidy is worth over \$629 million per year. That is in my opinion grossly unwarranted. Reducing or eliminating this subsidy would help bolster demand which has been lagging in recent permit auctions. (LOSSY)

Comment:

But the program can still be improved in several ways. The Petroleum Refining, Natural Gas Extraction, and Cement sectors received over 49 million free allowances in 2016. At \$12.73 per allowance, that subsidy is worth over \$629 million per year. Reducing or eliminating this subsidy would help bolster demand which has been lagging in recent permit auctions. (MEINZEN)

Comment:

No funding must be given to fossil fuel-based industries or any regulated entities under AB 32. (EJAC)

Response: See response to 45-day comment B-5.9.

B-6.22. Comment:

Transition Assistance to Industrial Sectors

We strongly support ARB's proposal to eliminate transition assistance to industrial sectors for the post-2020 program, and instead only freely allocate allowances based on leakage risk. In 2021, any credible argument for an additional allocation on the basis of 'transition assistance' will long since have vanished. As ARB acknowledges, the total value awarded to industrial sectors in the form of free allowances to date "likely exceeds compensation required for emissions leakage protection for most sectors."¹⁶¹ That excess may result in windfalls for industrial emitters at the expense of the public programs funded through auction proceeds. While we do not oppose providing assistance to industrial entities commensurate with their identified leakage risk, there is no longer any basis to award additional allowances for transitioning into a program that will be eight years old. (NRDC)

Response: Staff agrees that it is appropriate to eliminate transition assistance for post-2020 industrial allocation. See staff's response to 45-day comment B-6.1 for a discussion of the rationale for a step-down in allocation for medium and low leakage risk sectors starting with 2018 allowance allocation. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.23. Comment:

Staff proposes to eliminate transition assistance and allowances allotted for the Allowance Price Containment Reserve (APCR) beginning in 2021 and proposes

¹⁶¹ "Cap-and-Trade Regulation 2016 Amendments: Staff Presentation on a Methodological Framework for Emissions Leakage Designation for 2018 and Beyond," May 18, 2016, available at: <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/staff-leakage-workshop-methodology.pdf> (slide 16) (emphasis added).

complete elimination by 2030. ARB will freely allocate allowances to industrial sectors based on leakage risk.

Recommendation: Transition assistance and APCR should continue to be provided beyond 2021 and 2030. This would provide staff flexibility that would allow the cap-and-trade program to respond to market issues. As the cap declines, the cost of allowances will increase. (AGCOUNCIL)

Response: The Ag Council requests staff develop flexibility into the emissions leakage prevention methodology in response to market issues. Staff agrees a subsequent rulemaking will provide an opportunity to refine the post-2020 AF framework. In fact, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

See response to 45-day comment H-4.1 for a discussion of the APCR as it relates to the post-2020 timeframe.

B-6.24. Comment:

As for the 4th compliance period, I'm going to keep this very tight, as tight as I can on transition assistance elimination. We think that the transition -- transition assistance should be tied to the development of new technologies for companies under the cap and trade.

By doing that, what it does then is instead of just eliminating it out of hand, if any new technologies come along that result in a significant reduction in GHGs, then the -- then by sector, then you can look at the transition assistance and determine whether or not that needs to be lowered. (FOODPROCESSORS2)

Response: Staff declines to implement the proposed scheme of tying sector-specific assistance factors to technological development at an unknown pace. Doing so would establish an incentive to delay research, development, and deployment of technologies that can lower carbon emissions, and would not enable ARB to meet its AB 32 mandate to prevent emissions leakage to the extent feasible. Under the current allowance allocation mechanism, technologies that reduce GHG emissions are already incentivized.

See the response to 45-day comment B-6.1 for the rationale and history behind phasing out transition assistance to medium and low leakage risk sectors starting in 2018.

B-6.25. Comment:

The Current Scope of EITE Designations Do Not Adequately Account for “Leakage Risks” Faced by California Businesses.

The current Cap-and-Trade Regulation took steps to “minimize leakage” as required by California Health and Safety Code Section 38562(b)(8) by including provisions for free allocation of allowances to emissions intensive trade exposed (“EITE”) industries. The list of “industries” eligible for free allocation generally only includes companies in the manufacturing sector that exceeded the inclusion threshold during the initial rulemakings. Manufacturing is only a subset of California’s economy exposed to leakage risks. Technology and research and development companies can be highly energy intensive. Like companies in the manufacturing sector, the cap-and-trade can create leakage risks for these companies. In many ways, technology and R&D companies can be more easily moved to other states or countries due to the lower capital costs inherent in establishing a new technology and R&D facilities, such as data centers and engineering labs (i.e., compared to a major manufacturing facility with complex permitting requirements). As a matter of consistency in fulfilling the requirements set forth in Health and Safety Code Section 38562(b)(8), the ARB should evaluate new EITE designations for energy-intensive entities that are in technology and research and development sectors. The ARB should also consider EITE designations for entities that exceeded the cap-and-trade threshold after the initial review of EITE designations. Qualcomm believes this additional effort is necessary to ensure that the ARB meets the requirements of Health and Safety Code Section 38562(b)(8). (QUALCOMM)

Response: Qualcomm requests that staff implement a process for providing allocation to industrial facilities that become covered facilities¹⁶² after implementation of the C&T program. Qualcomm also requests extension of industrial allocation to technology and R&D businesses in California.

Industrial allocation is provided primarily to manufacturing and mining sectors. Within these broad NAICS sectors, see section 95891 of the Regulation for the existing process for establishing industrial allocation for new industrial covered facilities joining the program. New industrial NAICS have already entered the program and become newly-included in Table 8-1 for 2013-2020 allocation. For example, four new sectors were added to the existing sectors eligible for industrial allocation during the 2016 rulemaking. Providing an allowance allocation to any other sector is outside the scope of the 2016 rulemaking.

Allowance allocation is primarily restricted to manufacturing and mining sectors¹⁶³ with noticeable levels of trade exposure and emissions intensity, and thus staff declines to extend allocation to commercial facilities. The distinction between mining and manufacturing sectors, and other commercial sectors such

¹⁶² For example, such a facility might have had emissions less than 25,000mt CO₂e at the onset of the program, but exceeded 25,000mt CO₂e during the program (e.g., 2015).

¹⁶³ See Table 8-1 of the current regulation for a list of all sectors currently receiving industrial allowance allocation.

as technology and R&D facilities, are that mining and manufacturing facilities receiving industrial allocation emit carbon as part of their core business process.

C. COVERED SECTORS AND EXEMPT EMISSIONS

C-1. Exemptions

But-For Combined Heating and Power Exemption

C-1.1. Comment:

The ARB Should Not Remove the But-For CHP Exemption.

The Proposed Amendments would revise Section 95851 to phase out the “but-for-CHP exemption” when the natural gas sector is required to consign 100% of their cap-and-trade allowances. This removal is inconsistent with Board Resolution 12-33, which called for revisions to the Regulation that would “incentivize new, efficient distributed electricity generation technologies, such as Combined Heat and Power.” As discussed above, the natural gas sector is in a better position to achieve cost-effective emissions reductions. By removing the exemption and including small CHP systems in the cap-and-trade program, the ARB will disincentive these projects because the direct costs of complying with the cap-and-trade program will be more than the indirect GHG costs of the natural gas utility. Moreover, based on Qualcomm’s analysis for its CHP investments, installing the alternatives to CHP at its facilities were more GHG intensive than the efficient distributed generation technologies it deployed at the Qualcomm campus. Qualcomm therefore made an investment in CHP systems in order to reduce its GHG emissions. Removing the exemption would be inconsistent with the statutory requirement in California Health and Safety Code Section 38562(b)(1), which directs the ARB to encourage “early action” and the Board’s Direction in Resolution 12-33 to incentivize CHP.

Part of the intent behind the but-for-CHP exemption was a recognition that some activities that reduce GHG emissions compared to a business as usual scenario may be discouraged by a direct cap-and-trade compliance obligation. The exemption recognizes and incentivizes the net reduction in GHG emissions attributable to efficiently using the waste heat in a CHP system. Now that the natural gas sector is included in the program, small CHP facilities will be under the cap because natural gas utilities will pass through their GHG costs to facilities that fall below the threshold or otherwise exempt. For these reasons, the ARB should not remove the but-for-CHP exemption. (QUALCOMM)

Response: The commenter requests that the limited exemption of emissions from the production of qualified thermal output be extended indefinitely. Staff declines to make these changes.

The intent of this limited exemption was to provide equity for entities that are under the threshold and entities that would be under the threshold but for their

investments in CHP. The exemption is only appropriate during the time when there is a GHG cost difference between covered entities and non-covered entities that purchase natural gas. The Proposed Regulation, in addition to the probable outcome of CPUC proceeding R.14-03-003, are expected to result in full GHG cost pass-through in 2030. The amendments have the effect of extending the limited exemption of emissions from the production of qualified thermal output until the end of 2029. Starting in 2030, all entities that exceed the program inclusion threshold will have a compliance obligation under the Cap-and-Trade Regulation.

C-1.2. Comment:

The ARB Should Revise the But-For CHP Exemption to Account for Facilities that Contain Multiple, Cogeneration Units that Are Operated Independently of One Another.

Section 95852(j) sets forth an important Cap-and-Trade exemption that applies to any “facility with a cogeneration unit that meets the requirements of this section.” Based on the language in the exemption and the use of the words “facility” and “cogeneration unit”, the existing language in Section 95852(j) lacks clarity as to how the exemption should be applied to a facility with more than one cogeneration unit. Section 95852(j) can be read to apply at both the cogeneration unit level or the facility level. There are instances where there are multiple cogeneration units within a single facility boundary. The facility definition set forth in the Mandatory Reporting Regulation is broad and in certain instances encompasses multiple cogeneration units that are functionally separate, but are nevertheless part of the same facility due to common ownership. In these instances, if the cogeneration units are functionally separate, the exemption should be applied separately to each cogeneration unit. The ARB should amend Section 95852(j) to clarify that when cogeneration units are operated independently of one another, have separate air permits, and the thermal output is put to separate uses, then the cogeneration units will be evaluated separately under Section 95852(j). In these instances, the calculation set forth in Section 95852(j) should be calculated for each cogeneration unit. If each cogeneration unit satisfies the two conditions set forth in Section 95852(j)(1)(A) and (B), then each cogeneration unit should qualify for the exemption and the total emissions associated with the “facility” should be eligible for the limited exemption. (QUALCOMM)

Response: The commenter requests that ARB redefine the limited exemption of emissions from the production of qualified thermal output to be at the unit level rather than the facility level. Staff declines to make this change. This change does not match the intent of the exemption which is to account for facilities (as defined by MRR) that would fall below the Program compliance threshold of 25,000 metric tons of CO₂e “but for” their installation of CHP systems. This is only valid on the facility level and could not be applied to each unit separately.

Waste-to-Energy Exemption

C-1.3. Comment:

VI. NAIMA SUPPORTS CARB'S TWO-YEAR EXTENSION OF AN EXEMPTION OF RECYCLING PROGRAM FROM CARB'S PROPOSED AMENDMENTS

A limited exemption from a compliance obligation for emissions from the direct combustion of municipal solid waste in a waste-to-waste energy facility has been added by CARB for the 2016 and 2017 data years. CARB staff believes that it is appropriate to extend this limited exemption for two years as these options are further assessed. NAIMA supports CARB's recommendation as CalRecycle needs additional time to evaluate the treatment of end-of-life management options. (NAIMA)

Response: Thank you for the support.

C-1.4. Comment:

We support CARB's proposal to add an exemption from compliance obligations from emissions from the direct combustion of municipal solid waste at the state's three existing waste-to energy (WTE) facilities for the 2016 and 2017 emission data years. However that the fundamental reasons for the initial exemption are unchanged, we believe that this exemption should continue through the end of the 3rd compliance period in 2020. The rationale for initial exclusion is still valid, as landfills are still excluded from the cap & trade program, and the scientific & policy recognition of the GHG benefits achieved through the diversion of waste from landfill to WTE is stronger than ever. Inclusion of WTE in the cap beginning in 2018 would put WTE facilities at an economic disadvantage relative to landfilling, the financial impacts of which will be direr than in the past, as power prices have continued to slide and the Stanislaus WTE will no longer be considered renewable under state law. Lastly, inclusion of WTE in the cap in 2018 would put California's program in opposition to Ontario's, which has excluded WTE facilities through 2020.

Since the initial exemption of the existing WTE facilities in 2012, the recognition of WTE as a source of GHG mitigation has grown. This GHG mitigation is achieved by displacing grid connected fossil-fuel fired electricity, recovering metals from the waste stream for recycling, and most importantly, by avoiding landfill emissions of methane, a key short lived climate pollutant. The Center for American Progress and Third Way have both reviewed WTE and validated its GHG benefits.^{164,165} Recent work, completed by CARB itself, concluded that WTE offers GHG reductions relative to landfilling:

¹⁶⁴Center for American Progress (2013) Energy from Waste Can Help Curb Greenhouse Gas Emissions <http://www.americanprogress.org/wp-content/uploads/2013/04/EnergyFromWaste-PDF1.pdf>

¹⁶⁵ Third Way (2014) *Power Book: Energy from Waste*, <http://powerbook.thirdway.org/filter-web-app/energy-from-waste>, accessed November 26, 2014.

“Preliminary staff estimates ... indicate that combusting waste in the three MSW Thermal facilities in California results in net negative GHG emissions, ranging from - 0.16 to -0.45 MT CO₂e per ton of waste disposed, when considering that the waste would otherwise be deposited in landfills resulting in higher emissions.”¹⁶⁶

In addition, the Joint Institute for Strategic Energy Analysis (JISEA) operated on behalf of the U.S. Department of Energy’s National Renewable Energy Laboratory, the University of Colorado Boulder, the Colorado School of Mines, the Colorado State University, the Massachusetts Institute of Technology, and Stanford University published a report in 2013 after a review of solid waste management options for Boulder’s municipal solid waste concluded WTE was a better option than landfilling:

“We find that MSW combustion is a better alternative than landfill disposal in terms of net energy impacts and carbon dioxide (CO₂)-equivalent GHG emissions.

“Life cycle assessment studies published in the literature have generally been consistent in suggesting that MSW combustion is a better alternative to landfill disposal in terms of net energy impacts and CO₂-equivalent GHG emissions. The results from this study match that expectation. In this report, WTE leads to a higher reduction in emissions compared to landfill-to-energy disposal per kWh production.”¹⁶⁷

Here in California, Berkeley Law released a report earlier this year in response to a request from the Governor’s office, looking at the merits and demerits of energy recovery options for wastes remaining after reaching the state’s 75% recycling goal. The authors conclude that:

“Harvesting these leftover materials as solid waste energy sources could provide multiple environmental benefits:

- complementing intermittent renewable energy, such as wind and solar, to offset fossil fuelbased energy sources and associated greenhouse gas emissions; [and]
- avoiding landfill emissions of methane (a potent greenhouse gas that is 28-34 times as strong as carbon dioxide over 100 years) by diverting wastes to energy, particularly organic wastes;”¹⁶⁸

¹⁶⁶See Table 5 of California Air Resources Board (2014) Proposed First Update to the Climate Change Scoping Plan: Building on the Framework, Appendix C – Focus Group Working Papers, Municipal Solid Waste Thermal Technologies

¹⁶⁷Joint Institute for Strategic Energy Analysis (2013) Waste Not, Want Not: Analyzing the Economic and Environmental Viability of Waste-to-Energy (WTE) Technology for Site-Specific Optimization of Renewable Energy Options. <http://www.nrel.gov/docs/fy13osti/52829.pdf>

¹⁶⁸Berkeley Law Center for Law, Energy & the Environment (2016) *Wasting Opportunities: How to Secure Environmental &*

Clean Energy Benefits from Municipal Solid Waste Energy Recovery.
<https://www.law.berkeley.edu/research/clee/research/climate/waste-to-energy/>

Especially relevant, given California's dependence on the cap & trade program in developing its state measures plan to meet the EPA's new Clean Power Plan requirements, is the U.S. EPA's treatment of WTE under those requirements. WTE is a compliance option for reducing GHG emissions from electricity generation under the CPP. New EfW facilities are eligible to generate Emission Rate Credits (ERCs).¹⁶⁹ Existing facilities are not a covered source and are considered a source of no carbon energy under the program.¹⁷⁰

This ample additional recognition augments an already extensive list of international governments, NGOs, and researches that recognize the climate benefits of WTE, including the

U.S. EPA,^{171,172} U.S. EPA scientists,¹⁷³ the Intergovernmental Panel on Climate Change ("IPCC"),¹⁷⁴ the World Economic Forum,¹⁷⁵ the European Union,^{176,177} CalRecycle,¹⁷⁸ and other researchers.^{179,180}

¹⁶⁹40 CFR 60.5800

¹⁷⁰40 CFR 60.5845

¹⁷¹U.S. EPA Webpage, Energy Recovery from the Combustion of Municipal Solid Waste (MSW), accessed September 19,

2016. <https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw>

¹⁷²U.S. EPA Archived Webpage, Air Emissions from MSW Combustion Facilities, accessed September 19, 2016. <https://archive.epa.gov/epawaste/nonhaz/municipal/web/html/airem.html>

¹⁷³Kaplan, P.O, J. DeCarolus, and S. Thorneloe, 2009, Is it better to burn or bury waste for clean electricity generation? *Environ. Sci. Technology* 43 (6) pp1711-1717. Available at: <http://pubs.acs.org/doi/abs/10.1021/es802395e>

¹⁷⁴ EfW identified as a "key mitigation measure" in IPCC, "Climate Change 2007: Synthesis Report. Contribution of Work Groups I, II, and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change" [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]. IPCC, Geneva, Switzerland, 104 pp. Available at: http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_synthesis_report.htm

¹⁷⁵ EfW identified as a key technology for a future low carbon energy system in World Economic Forum. *Green Investing: Towards a Clean Energy Infrastructure*. January 2009. Available at: <http://www.weforum.org/pdf/climate/Green.pdf>

¹⁷⁶ EU policies promoting EfW as part of an integrated waste management strategy have been an overwhelming success, reducing GHG emissions over 72 million metric tonnes per year, see European Environment Agency, *Greenhouse gas emission trends and projections in Europe 2009: Tracking progress towards Kyoto targets* http://www.eea.europa.eu/publications/eea_report_2009_9

¹⁷⁷ European Environmental Agency (2008) Better management of municipal waste will reduce greenhouse gas emissions. Available at: http://www.eea.europa.eu/publications/briefing_2008_1/EN_Briefing_01-2008.pdf

¹⁷⁸ CalRecycle. 2012. CalRecycle Review of Waste-to-Energy and Avoided Landfill Methane Emissions. Available at: <http://www.calrecycle.ca.gov/Actions/PublicNoticeDetail.aspx?id=735&aiid=689>

¹⁷⁹ Weitz, K., Thorneloe, S., Nishtala, S., Yarkosky, S., and Zannes, M. (2002). "The impact of municipal solid waste management on greenhouse gas emissions in the United States." *J. Air Waste Manage.Assoc.*, 52, 1000–1011

¹⁸⁰ Thorneloe, S., Weitz, K., and Janbeck, J. (2005). "Moving from solid waste disposal to materials management in the United States." *10th Int. Waste Management and Landfill Symp., International Waste Working Group, Padova, Italy*.

EfW facilities generates carbon offsets credits under both the Clean Development Mechanism (CDM) of the Kyoto Protocol and voluntary carbon offset markets.^{181,182} Under CDM, more than 40 EfW projects have been registered, with a combined annual GHG reduction of 5 million metric tons of CO₂e per year.¹⁸³ To date, three EfW expansions have been validated as carbon offset projects in North America. The Lee and Hillsborough County facilities, operated on behalf of municipal owners in Florida, have been selling carbon credits into the voluntary market for several years.

Concurrently, new data show that the methane emitted by landfills and other sources is even more damaging than previously thought. Methane is the second largest contributor to global climate change.¹⁸⁴ A short lived climate pollutant (SLCP) increasingly under international scrutiny, methane has a much larger climate impact than previously reported and its atmospheric concentrations continue to rise (Figure 5).¹⁸⁵ According to the IPCC's 5th Assessment Report, methane is 34 times stronger than CO₂ over 100 years when all of its effects in the atmosphere are included and 84 times more potent over 20 years.¹⁸⁶

Fast action to reduce SLCPs, including methane, has the potential to slow down the global warming expected by 2050 by as much as 0.5 Celsius degrees.”¹⁸⁷ A failure to address SLCPs, like methane, significantly increases the risk of crossing the 2°C

¹⁸¹ Clean Development Mechanism Executive Board: “Approved baseline and monitoring methodology AM0025: Avoided emissions from organic waste through alternative waste treatment processes.” Available at: <http://www.cdm.unfccc.int/methodologies/DB/3STKBX3UY84WXOQWIO9W7J1B40FMD>

¹⁸² Verified Carbon Standard Project Database, <http://www.vcsprojectdatabase.org/> See Project ID 290, Lee County Waste to Energy Facility 2007 Capital Expansion Project VCU, and Project ID 1036 Hillsborough County Waste to Energy (WtE) Facility 2009 Capital Expansion Unit 4.

¹⁸³ CDM Project Database, project methodologies AM0025, ACM0022, accessed 6/9/2015, <https://cdm.unfccc.int/Projects/projsearch.html>

¹⁸⁴ See Figure SPM.5 of IPCC (2013) Summary for Policymakers. In: Climate Change 2013: The Physical Science Basis.

Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., et al. (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_SPM_FINAL.pdf

¹⁸⁵ World Meteorological Organization (2014), *WMO Greenhouse Gas Bulletin: The State of Greenhouse Gases in the Atmosphere Based on Global Observations through 2013*, 10, September 9, 2014. Available at: <https://drive.google.com/file/d/0BwdvoC9AeWjUd0IPWXBMU1VmNGc/view>

¹⁸⁶ The IPCC concluded that “it is likely that including the climate-carbon feedback for non-CO₂ gases as well as for CO₂ provides a better estimate of the metric value than including it only for CO₂.” See p714 & Table 8-7 of Myhre, G. et al. (2013) *Anthropogenic and Natural Radiative Forcing*. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., et al. (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

¹⁸⁷ Climate and Clean Air Coalition website, accessed 9/2/2014. <http://www.unep.org/ccac/Short-LivedClimatePollutants/BenefitsofMitigation/tabid/130286/Default.aspx>

temperature increase threshold widely discussed as most likely to limit severe climate change impacts.¹⁸⁸

Auspiciously, California has a comprehensive plan to reduce emissions of SLCPs in the form of SB1383 recently passed by the Legislature. We fully support the diversion of organics materials from landfills called for in SB1383 to higher and better uses of this material. Technologies like well-managed composting and anaerobic digestion that generate a usable product returning carbon and nutrients to the soil should be prioritized, however, energy recovery, including the three existing WTE facilities, has an important role to play. WTE facilities are particularly well suited to manage contaminated organic waste streams that can prove problematic for technologies like composting and anaerobic digestion. In addition, diverting organics to WTE realizes significant GHG benefits. A 2016 peer-reviewed paper published in *Environmental Science & Technology* confirms the value that WTE can bring to organics management, concluding that “it is beneficial to divert food waste from a landfill to AD, composting, or WTE but often not beneficial to divert food waste from WTE.”¹⁸⁹

We recognize that the steps the California legislature and CARB have taken to divert organics from landfilling will impact the composition of the waste stream that is managed in WTE. However, we do not think it is appropriate to presume the results of these actions, or their effect on the GHG benefits of WTE relative to landfilling. Most importantly, the benefits of WTE and other diversion technologies like anaerobic digestion and composting is not diminished by the success achieved in landfill diversion, particularly when these technologies will likely play the largest role in that success. Instead, the GHG benefits of these technologies should be evaluated against the baseline scenario without policy actions like SB1383. Additionally, while SB1363 has set a target to reduce organics disposal by 50% by 2020 relative to 2014, it expressly forbids even the adoption of regulations that would implement that target until 2025.

The case for WTE’s benefits relative to landfilling have only become stronger over the past four years. As a result, WTE should be excluded through the end of the 3rd compliance period so that WTE facilities would not be put at an economic disadvantage relative to landfilling and the state can continue to rely on their ability to mitigate GHG emissions relative to landfilling. However, CARB should develop a science-based and transparent process to evaluate the net lifecycle GHG impact of organics diversion on the waste streams managed by the state’s three WTE facilities as well as the potential impacts of the inclusion of WTE in the cap and trade program on lifecycle GHG emissions from the waste management sector for the post-2020 period.

¹⁸⁸ Shindell, D. *et al.*, (2012) Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security, *Science*, **335**, 183-189.

¹⁸⁹ Hodge, K.L., J.W. Levis, J.F. DeCarolis, M.A. Barlaz (2016) Systemic Evaluation of Industrial, Commercial, and Institutional Food Waste Management Strategies in the United States, *Environ. Sci. Technol.* 2016, 50, 8444–8452. <http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00893>

In light of AB197 and in recognition of other jurisdictions which have successfully achieved significant reductions in the waste management sector through the implementation of an integrated approach, CARB should consider if other policy mechanisms implemented in lieu of cap and trade are more suitable for the sector. The European Union Emissions Trading Scheme (EU-ETS), the largest and longest running carbon cap and trade program, excludes waste management from the cap.¹⁹⁰ In its place, the EU has a set of complementary policies pertaining to the sector, including a landfill directive which calls for a minimum 65% biodegradable waste diversion from landfills to alternatives, including recycling, composting, anaerobic digestion, and WTE.^{191,192,193} This integrated approach, entirely outside of the their cap and trade program, resulted in the biggest GHG reductions in any sector in the EU economy on a percentage basis (34%).¹⁹⁴ Just recently affirmed and expanded through the 2015 Circular Economy Package, we believe this type of an approach could be a model for California. (COVANTA)

Response: The commenter opposes the end of the limited exemption from a compliance obligation for emissions from waste-to-energy facilities through the end of 2017, and lists many reasons why they believe a limited exemption is appropriate. One initial reason for this exemption was to avoid any increases in landfill emissions due to reduced diversion if the waste-to-energy facilities had a compliance obligation under the Program. Current and future policies are such that landfill emissions are not expected to increase due to lack of diversion to waste-to-energy facilities. Existing State policies focus on the highest and best use of waste materials, in particular recycling, composting and anaerobic digestion. As mentioned in the comment, SB 1383 requires implementation of the Short-Lived Climate Pollutant (SLCP) Strategy by January 1, 2018, and codifies the 2030 SLCP emissions reduction targets, which specify reducing landfill methane via diversion of organic materials. Organic waste entering landfills must be reduced by 50% from 2014 levels by 2020, and by 75% from 2014 levels by 2025. CalRecycle and ARB will collaborate to develop regulations by late 2018 to divert organics from landfills, with regulations to take effect on or after January 1, 2022. This requirement is in addition to California's existing Landfill Methane Control Measure, which requires the

¹⁹⁰ EU (European Union) (2003) Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC. *Official Journal of the European Union*. L275, **46**, 32-46.

¹⁹¹ European Union, EU (2008) Directive 2008/98/EC of the European Parliament and of the Council of 19 November 2008 on waste and repealing certain Directives. *Official Journal of the European Union*. L312, **51**, 3-30

¹⁹² EU (European Union) (1999) Council Directive 1999/31/EC of 26 April 1999 on the landfill of waste. *Official Journal of the European Communities*. L182, 42, 1-19.

¹⁹³ EU (European Union) (1994) European Parliament and Council Directive 94/62/EC of 20 December 1994 on packaging and packaging of waste. *Official Journal of the European Communities*. L365, 10-23.

¹⁹⁴ European Environment Agency, Greenhouse gas emission trends and projections in Europe 2009: Tracking progress towards Kyoto targets http://www.eea.europa.eu/publications/eea_report_2009_9

installation of a landfill gas collection and control systems on landfills that meet certain criteria. Staff believes that it is appropriate to extend this limited exemption through the end of 2017, as proposed.

With regard to alignment with Ontario's Cap-and-Trade Program, staff notes that Ontario's program is sufficiently aligned with California's to enable program linkage, and that linkage does not require identical sector coverage. For instance, Québec assigns a compliance obligation to SF₆ under its cap-and-trade system, whereas ARB regulates SF₆ through a separate regulation.

C-1.5. Multiple Comments:

Oppose exemption for "Waste To Energy" in Cap & Trade, Oppose Cap and Trade for CPP compliance

In its Initial Statement of Reasons ("ISOR") for the Cap and Trade regulation extension, CARB proposes extending the existing exemption for the state's three garbage incinerators (or "waste to energy") under the cap and trade program. This "exemption from a compliance obligation" would be for an industry that emits carbon dioxide and other harmful pollutants in three environmental justice communities.

At a bare minimum, the state must align with the requirements of the CPP on this point. The CPP clearly recognizes that GHG emissions from burning the fossil fuel-based portion of garbage (including plastics) must be counted. The CPP also acknowledges that incineration undermines waste prevention programs, which have significant climate benefits.

Any proposal to meet the CPP must, therefore eliminate any exemption from compliance with GHG regulation for "waste to energy."

Exempting biogenic carbon from California climate regulation, including the Cap and Trade program, is causing other unintended consequences. CARB must examine the climate impacts of burning biomass, including the biological portion of municipal solid waste that is burned in such municipal waste incinerators. There is substantive harm to the climate and human health when such materials are burned, and incineration means these materials are not being composted and returned to the soil to store long term carbon.

The EJAC made similar recommendations to CARB about these particular points in the recommendations finalized August 26, 2016, on pages 16-19. (Available at https://www.arb.ca.gov/cc/ejac/ejac_recommendations082616revised.pdf) (GAIA)

Comment:

No credits must be given for landfill or for biodigestors for greenhouse gas avoidance. The state's biomass garbage and all other incinerators, including but not limited to gasification, will be treated like other carbon-intensive industries and pay for all carbon emissions under California's Cap and Trade program. At a bare minimum, the state

must align with the requirements of the EPA's Clean Power Plan (CPP) on this point. The CPP clearly recognizes that carbon dioxide emissions from burning the fossil fuel-based portion of garbage (i.e., plastics) must be counted. CPP also acknowledges that incineration undermines waste prevention programs, which have significant climate benefits. Beyond this minimum accounting requirement, the state already recognizes the benefits of using compost (from food, paper, wood, yard waste, and other natural materials in the waste stream) to store carbon in the soil. Thus, the carbon dioxide emissions of burning such materials must also be counted in the state's Cap and Trade program. Additionally, the state must revoke all existing incinerator carbon credits. Disincentivize and discourage locating biomass and digesters in disadvantaged communities or in close proximity to housing. (EJAC)

Comment:

I also am here to speak on a specific point that our organization works on in California and around the world, which is incineration. Deep in the staff proposal in front of you on the Cap-and-Trade Program is a proposal to extend the exemption that incinerators currently enjoy under the Cap-and-Trade Program in California.

These polluting facilities have already gotten off the hook for the first compliance period. And at that time, we were told, along with EJAC and other people who were -- organizations who were concerned about this, that this would be a one-time exemption. So it's a shame that we still have to spend time talking about this when we have so many more systemic issues to be focusing on today.

So I'll be brief with 3 reasons of the many reasons why I would encourage you for -- that ARB keep its promise on putting incinerators under the cap.

The first is that the State's incinerators are polluting environmental justice communities with co-pollutants, in addition to greenhouse gases. The second is that the Clean Power Plan clearly states that compliance mechanisms should apply to incineration. That's pretty clear. The third is that a lot of what gets burned in the State's incinerators is organic material like food waste and urban wood waste, things like that. That's material that we should be using in compost facilities and then applying to California's lands in order to sequester carbon in the long run, not putting in these incentives which actually incentivize burning it.

So, you know, it's a little bit hard to understand why we still have to address this issue when the State, including ARB and other agencies, have done a lot of work moving us forward on the nexus of waste, policy, and climate policy. So to move -- to agree to another extension for incinerators would be a step backwards. So I'd encourage us to keep on the path that we're on around composting and carbon sequestration.

And, you know, in sum overall of my comments, I want to say please give California a plan past 2020 that does not include trading, and through 2020 as long as there is Cap-and-Trade Program incinerators should be under that cap. (GAIA2)

Response: The commenters oppose extending the exemption for waste-to-energy facilities through the second compliance period, citing concerns about air emissions from these facilities and consistency with EPA's Clean Power Plan. Staff agrees that waste-to-energy facilities should have a compliance obligation. Starting in 2018, operators of waste-to-energy facilities that meet or exceed the Program emissions threshold will have a compliance obligation for GHG emissions from the combustion of waste.

Air pollutant emissions from waste-to-energy facilities, also known as solid waste incinerators, are regulated by local air districts and are subject to a performance standard promulgated pursuant to section 111 or 129 of the EPA Clean Air Act (CAA). The CAA limits air emissions of particulate matter, dioxins/furans, sulfur dioxide, nitrogen oxides, hydrogen chloride, lead, mercury, and cadmium from four categories of solid waste incineration units, including municipal solid waste incinerators. The rule and guidelines set emissions limits for waste-to-energy facilities, which are enforced via the local air district's permitting process, and serve to protect public health and the environment by reducing emissions of harmful air pollutants.

With respect to the comment about CPP, CPP states "When developing their plans, states planning to use waste-to-energy as an option for the adjustment of a CO₂ emission rate should assess both their capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs." California is taking steps to avoid such negative impacts. SB 1383 requires implementation of the SLCP Strategy by January 1, 2018, and codifies 2030 SLCP emission reduction targets, which specify reducing landfill methane via diversion of organic materials. Organic waste entering landfills must be reduced by 50 percent from 2014 levels by 2020, and by 75 percent from 2014 levels by 2025. CalRecycle and ARB will continue to evaluate the treatment of end-of-life management options for municipal solid waste, such as composting, recycling, landfilling, and generating energy, under the Program and will collaborate to develop regulations by late 2018 to divert organics from landfills, with regulations to take effect on or after January 1, 2022.

The comment about exempting biogenic carbon from California climate regulations is outside the scope of the current regulatory changes.

Biofuel Exemptions

C-1.6. Multiple Comments:

California's Cap-and-Trade Program Fails to Account for the Climate Impacts of Forest-Sourced Woody Biomass in Bioenergy Production.

California's continuing refusal to address biomass emissions under the cap-and-trade program—and, accordingly, under the Clean Power Plan Compliance Plan built around the cap-and-trade program—is contrary to science and unsupportable, and undermines the integrity and effectiveness of the cap as a whole. The Cap-and-Trade regulation exempts emissions from combustion of many forms of biomass from any compliance obligation whatsoever, and thus effectively treats biomass as “carbon neutral”; this exemption is completely out of step with prevailing scientific knowledge.¹⁹⁵ Extending this exemption beyond 2020 would be arbitrary, capricious, and indefensible.

Treating biomass as effectively carbon neutral is also inconsistent with the limits imposed on biomass energy generation as a compliance measure in the CPP.¹⁹⁶ In the CPP, EPA confirmed that its own Science Advisory Board panel and its revised draft “Framework” for biomass carbon accounting had explicitly rejected the assumption that all biomass combustion can be considered “carbon neutral.” (Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,885 (Oct. 23, 2015) (“Final CPP”).) Rather, “the net biogenic CO₂ atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.” (*Ibid.*)

The CPP thus provided that states may use only “qualified biomass”—defined as “a biomass feedstock that is demonstrated as a method to control increases of CO₂ levels in the atmosphere (40 C.F.R. § 60.5880)—in demonstrating compliance with either a rate-based or a mass-based emissions goal.¹⁹⁷ (Final CPP, 80 Fed. Reg. at p. 64,886.) “Not all forms of biomass are expected to be approvable as qualified biomass (i.e.,

¹⁹⁵ The Center has addressed these issues in detail elsewhere. (See Center for Biological Diversity, Comments on the Proposed Short-Lived Climate Pollutant Strategy (May 26, 2016), available at <https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=slcp2016> [comment nos. 94, 96, 97]; Center for Biological Diversity, Comments on Second Set of Proposed Modifications to the AB 32 Greenhouse Gas Cap-and-Trade Regulation (Sept. 27, 2011), available at <https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade10> [comment no. 93]; Center for Biological Diversity, Comments on the Proposed Greenhouse Gas Cap-and-Trade Regulation (December 15, 2010), available at <https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade10> [comment nos. 718, 746].) Each of the comment letters referenced in this footnote, and all exhibits submitted with those letters, are hereby incorporated by reference.

¹⁹⁶ The Center has also addressed this issue in its comments on California's proposed CPP Compliance Plan, filed under separate cover today.

¹⁹⁷ EPA's proposal for allowance trading under a federal mass-based implementation plan would require covered facilities co-firing with biomass to hold allowances for all of their CO₂ emissions, including emissions from biomass; EPA sought comment on an alternative approach allowing facilities to identify “qualified biomass” and “potential methods for demonstrating compliance, and thus reduc[ing] the mass emissions attributed to” an EGU cofiring with biomass. (Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations, 80 Fed. Reg. 64,966, 65,012 (Oct. 23, 2015).) Although EPA has not yet finalized the proposal, it confirms provisions in the Final CPP indicating that “qualified biomass” requirements apply to both mass-based and rate-based compliance options.

biomass that can be considered as an approach for controlling increases of CO₂ levels in the atmosphere).” (*Ibid.*)

Accordingly, State plan submissions must describe the types of biomass that are being proposed for use under the state plan and how those proposed feedstocks or feedstock categories should be considered as “qualified biomass” (i.e., a biomass feedstock that is demonstrated as a method to control increases of CO₂ levels in the atmosphere). The submission must also address the proposed valuation of biogenic CO₂ emissions (i.e., the proposed portion of biogenic CO₂ emissions from use of the biomass feedstock that would not be counted when demonstrating compliance with an emission standard, or when demonstrating achievement of the CO₂ emission performance rates or a state rate-based or mass-based CO₂ emission goal). (*Ibid.*)

EPA will “review the appropriateness and basis for proposed qualified biomass and biomass treatment determinations and related accounting, monitoring and reporting measures in the course of its review of a state plan,” and the agency will base its “determination that a state plan satisfactorily proves that proposed biomass fuels qualify . . . in part on whether the plan submittal demonstrates that proposed state measures for qualified biomass and related biogenic CO₂ benefits are quantifiable, verifiable, enforceable, non-duplicative and permanent.”

The Compliance Plan relies entirely on the cap-and-trade regulation, which in turn treats virtually all biomass generation as “carbon neutral”—directly contrary to EPA’s intent in the federal CPP. Indeed, as the Center’s comments in other contexts (see footnote 1, *supra*) and supporting materials indicate, it is extremely doubtful that many, if any, biomass resources typically used in California can be verifiably demonstrated to “control” atmospheric CO₂ concentrations on the timescales relevant to the CPP (i.e., between 2022 and 2030).

This problem alternatively could be described as a leakage problem: generation and emissions from CPP-covered EGUs, which bear regulatory costs under cap-and-trade, may “leak” to biomass units, which are not covered EGUs and bear no similar regulatory costs. The effect of this leakage on the atmosphere could be dramatic. California’s CPP-covered EGUs had a combined emissions rate of 870 lbs/MWh in 2014. (Compliance Plan at p. 12.) A new biomass steam turbine, in contrast, would have an emissions rate of more than 3,000 lbs/MWh at the smokestack.¹⁹⁸ Absent a sound, verifiable demonstration that California biomass actually controls atmospheric CO₂ concentrations, leakage to biomass facilities could dramatically undermine achievement of California’s overall CPP emissions target, as well as threatening California’s ability to attain the emissions reduction targets established in AB 32, SB 32, and Executive Orders S-3-05 and B-30-15.

¹⁹⁸ This figure is based on heat rate and efficiency data from the Department of Energy, Energy Information Administration, and Oak Ridge National Laboratory. (See Partnership for Policy Integrity, CO₂ Emission Rates for Modern Power Plants (Sept. 2016) (Attachment 1 hereto).)

Attachment 1.

CO₂ Emission Rates for Modern Power Plants (Sept. 2016) Published by the Partnership for Policy Integrity.

CO₂ Emission Rates From Modern Power Plants

	Lb CO ₂ /MMBtu	Facility efficiency	MMBtu /MWh	Biomass v. Lb CO ₂ /MWh	Tech
New gas combined cycle ^a	117	51%	6.7	786	385%
New subcritical coal steam turbine ^b	210	39%	8.7	1,839	165%
U.S. coal fleet avg, 2013 ^c	210	33%	10.5	2,198	138%
New biomass steam turbine ^d	213	24%	14.2	3,028	

References:

CO₂ per MMBtu

a, b, c : from EIA at http://www.eia.gov/environment/emissions/co2_vol_mass.cfm. Value for coal is for "all types." Different types of coal emit slightly more or less.

d: Assumes HHV of 8,600 MMBtu/lb for bone dry wood (Biomass Energy Data Book v. 4; Oak Ridge National Laboratory, 2011. <http://cta.ornl.gov/bedb>.) and that wood is 50% carbon.

Efficiency a: DOE National Energy Technology Laboratory: Natural Gas Combined Cycle Plant F-Class (http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf)

b: International Energy Agency. Power Generation from Coal: Measuring and Reporting Efficiency Performance and CO₂ Emissions. https://www.iea.org/ciab/papers/power_generation_from_coal.pdf

c. EIA data show the averaged efficiency for the U.S. coal fleet in 2013 was 32.6% (http://www.eia.gov/electricity/annual/html/epa_08_01.html)

d: ORNL's Biomass Energy Data Book (<http://cta.ornl.gov/bedb>; page 83) states that actual efficiencies for biomass steam turbines are "in the low 20's"; PFPI's review of a number of air permits for recently proposed biopower plants reveals a common assumption of 24% efficiency. (CBD)

Comment:

Do not exempt biomass burning activities...

Do not provide energy credits for biomass burning or count it as renewable energy.

Make wood chips available from dead trees to use as mulch in gardens (don't burn it).

(EJAC)

Response: The commenters request that biomass not be exempt from a compliance obligation. The exemption of biomass combustion emissions was not modified as part of this rulemaking, and is therefore outside the scope of the current rulemaking. One commenter also requests that ARB align the Cap-and-Trade Regulation's biomass provisions with U.S. EPA's CPP requirements. While it is true that U.S. EPA is developing stricter qualified biomass requirements for use in CPP Compliance Plans, the relevant provision of the CPP emission guidelines, 40 CFR 60.5800(d)(1), is explicitly for rate-based plans, under which biomass is used to generate ERCs. Since California's plan is not a rate-based compliance plan, this provision does not apply.

C-1.7. Comment:**§ 95852.1.1 Eligibility Requirements for Biomass-Derived Fuels.**

The eligibility requirements in §95852.1.1 for biomass-derived fuels continue to apply only to biogas and biomethane among all biofuels. Under the regulations, biomethane is the only biofuel that is required to demonstrate compliance with complex "resource shuffling" rules in order to obtain exempt status. The proposed regulations maintain this inequitable treatment. We urge the ARB to treat all biofuels the same – either all biofuel should be compelled to comply with resource shuffling eligibility requirements or no biofuels should be required to comply with these requirements. There is no scientific or policy justification we are aware of that would support singling offsets out biomethane and making biomethane, alone among all biofuels, subject to resource shuffling requirements when used as a vehicle fuel.

For this reason, we strongly urge the Air Resource Board to simply make biomethane vehicle fuel exempt under the MRR and Cap and Trade on equal footing with all other biofuels when used in transportation. The Regulation should promote the growth of all renewable fuel and not give any manner of preferential treatment to one fuel over another. We recognize that biomethane is also used in California as a fuel for renewable power generation. We would support continued application of resource shuffling requirements to biomethane used for power generation.

In the event that the ARB decides to apply resource shuffling requirements evenly across all transportation biofuels, we would urge the ARB to further clarify and expand the resource shuffling rules as follows:

- (1) Any biofuel should be exempt from MRR and Cap & Trade through 2020 if the certified LCFS pathway(s) through which the biofuel is delivered to California demonstrates a 20% reduction from petroleum fuel. A 20% reduction represents 2x what the target is for the entire fuel supply for California by 2020 under the LCFS. It would appear axiomatic to us that a biofuel that is well ahead of the compliance schedule under LCFS should not also carry a Cap and Trade obligation.
- (2) Biomethane voluntarily recovered from landfills or other biogas sources that is not required to be captured under EPA's New Source Performance Standards (NSPS) or relevant state law that is delivered to California for end use as transportation fuel should automatically be deemed exempt.
- (3) Biomethane from projects that commenced injection of the product into the pipeline after Jan 1, 2010 should be considered exempt. The rationale for this exemption is that, since 2010, the price of fossil fuel natural gas has been insufficient to sustain production of biomethane from any biogas resource. In addition, the California RPS market (the largest market for biomethane historically) has been closed to product produced outside the State since 2012. In order to enable these projects to access the California vehicle fuel carbon market and sustain operations, they should be deemed exempt. Failure to do so risks pushing these projects into failure, which would result in flaring or venting of the methane and run counter to California GHG reduction goals. (CLEANEN)

Response: The commenter requests modifications to both MRR and the Cap-and-Trade Regulation. The comments regarding MRR as well as those proposed for the Cap-and-Trade Regulation are outside the scope of this rulemaking.

ARB notes that resource shuffling concerns noted in the 2010 rulemaking still apply. Biomethane is specifically susceptible to resource shuffling concerns as it is readily and easily transportable via the extensive network of common carrier pipelines across the US. As defined in the Regulation, "Biomethane" means "biogas that meets pipeline quality natural gas standards," which specifically identifies biomethane, apart from other biomass derived fuels, as indistinguishable from fossil natural gas for GHG reporting purposes.

The Cap-and-Trade Program's requirements are designed to avoid a situation in which there is no net change in GHG emissions to the atmosphere as a result of incentives inherent to the Program, such as the incentive to purchase imported biomethane, which is treated as an exempt fuel under the Program. The biomethane provisions are thereby designed to ensure that imported biomethane does not simply come from sources that were previously sending biomethane to facilities out of State. To allow for biomethane supplied under previously existing contracts that was previously being sent to entities outside the State would result in resource shuffling.

The purchaser of imported biomethane who wishes to classify the fuel as exempt must show an ARB-accredited verifier that their contracts for imported

biomethane include new sources of fuel or an increased production of fuel at an existing facility. To date, entities have been able to successfully show that they have purchased imported biomethane that meets these requirements and thereby have classified their fuel as exempt.

C-1.8. Comment:

Clean Energy is committed to helping California achieve its overall carbon reduction goals and will continue to support the ARB in its efforts in managing the MRR and Cap and Trade programs. Clean Energy appreciates the ARB's commitment to fixing issues in the MRR and Cap and Trade program that have been raised to this point and we recognize the immense complexity of the task. We believe our recommendations on revision of the MRR and Cap and Trade Regulation will strengthen the programs, avoid unintended consequences, ensure that biofuels are treated equally and that in-state and out-of-state LNG producers are treated equally with respect to their California carbon emissions. The Regulation must be equally applied across all fuels and market participants to ensure California meets its carbon reduction goals in an equitable manner. (CLEANEN)

Response: Staff appreciates the expressed commitment to helping California achieve its emissions reduction goals. Staff aims for a Program that, where appropriate, treats fuels, facilities, and emissions equitably and appreciates the input and participation in the process to improve the Cap-and-Trade Program through the rulemaking process.

Liquefied Natural Gas Supplier Exemption

C-1.9. Comment:

§ 95852 (a)(1) Limited Exemption for Emissions from LNG Suppliers

We appreciate that the ARB has proposed a limited exemption for LNG suppliers from Cap and Trade obligations during 2015, 2016 and 2017. As we understand the proposed regulation, LNG suppliers that qualify for the exemption will be allocated credits in equivalent volume to those they retired to meet their 2016 obligation and in equivalent volume to those needed to meet the compliance obligation for 2017 and 2018. We believe we will qualify for this exemption. However, we remain concerned that we will incur a significant cost in 2016 to purchase credits to cover our 2015 compliance obligation that we will never be able to recover. This is a result of the fact that we do not anticipate having a need for the credits that will be issued to replace those that we purchased and retired. As such, we would request the ARB modify the exemption to allow entities that qualify for the exemption to sell the credits that they are allocated for the 2015 compliance obligation, or pledge them to the ARB auction. This will enable us to recover the costs we incur purchasing credits to cover our 2015 compliance obligation. (CLEANEN)

Response: Staff believes that this comment pertains to section 95852(l)(1), not section 95852(a)(1), of the Regulation. The comment correctly states that the proposed amendments include a limited exemption from a Cap-and-Trade Program compliance obligation during the second compliance period, which is 2015, 2016, and 2017. Under the proposed amendments, LNG suppliers that qualify for the limited exemption will recover costs associated with the 2015 compliance obligation through true-up allocation that will be provided by ARB by October 24, 2017. For this true-up allocation, the number of allowances used by the qualifying LNG supplier to meet its 2015 annual compliance obligation will be freely allocated to the supplier's annual holding account. The allowances allocated to the annual holding account may be sold on the secondary market, allowing the LNG supplier to recover costs associated with Program compliance in 2015.

Fuel Cell Exemption

C-1.10. Comment:

Eliminating Qualified Export and Natural Gas Fuel Cell Exemptions

...We also support eliminating the exemption for emissions from natural gas hydrogen fuel cells in advance of the third compliance period. Consistent with staff's analysis and our position on requiring full consignment for natural gas suppliers, removing this exemption will maintain a level playing field for natural gas emissions sources and reduction technologies. (NRDC)

Response: Thank you for the support.

C-1.11. Multiple Comments:

1. Existing State Policy Recognizes the Environmental Benefits of Fuel Cells.

The use of clean, onsite distributed energy generation offers a path to move away from California's reliance on centralized power plants that produce harmful health and environmental impacts. Customers who use clean, onsite power are able to generate electricity—using fuel cells and other GHG reducing technologies—at the location where it will be immediately used helping to meet the State's environmental goals. ARB recognized the environmental and energy benefits of natural gas fuel cells and elected to exempt these GHG emissions from a compliance obligation under the Cap-and-Trade Program.¹⁹⁹ At the same time, ARB acknowledged that natural gas suppliers would be assessed compliance obligations starting in 2015, and that the supplier would “pass GHG compliance costs to the end user of the fuel as an incentive to spur efficient technology investment such as that provided by fuel cells.”²⁰⁰ It is also important to note that natural gas fuel cells are paving the way for biogas fuel cells as fuel cell technology becomes more common place and the price of biogas decreases.

¹⁹⁹ Letter from ARB to Bloom Energy dated May 23, 2013

²⁰⁰ Ibid.

On any fuel source, whether biogas or natural gas, fuel cells reduce both GHG and criteria air pollutant emissions compared to generation from the current grid. Since the Cap-and-Trade Program began, the ARB has recognized these environmental benefits and the energy system benefits of fuel cell technologies and, accordingly, has not imposed a direct compliance obligation on fuel cell customers. Instead, fuel cell customers will see a GHG price signal and will be part of the Cap-and-Trade program through the inclusion of the natural gas sector in the Cap-and-Trade program. CPUC Decision 15-10-032 directs the natural gas utilities to pass through GHG costs to all customers in the transportation portion of natural gas rates. While the gas utilities have not yet included GHG costs in the natural gas transportation rates, GHG costs since 2015 are accruing in a memorandum account and will be passed on to natural gas fuel cell customers. Regardless of when the Commission lifts the suspension on GHG cost pass through, fuel cell customers will pay for all GHG costs incurred since 2015.

2. The ARB Should Not Remove Fuel Cells from the List of Emissions Without a Compliance Obligation.

Staff has proposed to reverse the treatment of fuel cells under the Cap-and-Trade in the recent proposed amendments before the Board by removing Section 95852.2(b)(2). The Staff's rationale for the proposed deletion is that emissions from fuel cells are the same as other emissions and therefore fuel cell emissions should count toward compliance obligations in the regulation. However, emissions from natural gas fuel cells are already accounted for through Cap-and-Trade regulation of the natural gas sector and existing law already requires GHG costs to be passed through to natural gas customers. In addition, inclusion of natural gas fuel cells fails to account for the fact that fuel cells are typically much less GHG intensive and displace conventional generation that would otherwise be associated with supplying energy by the utility. By removing fuel cells from Section 95852.2, the ARB may discourage this emissions displacement.

3. Natural Gas Fuel Cells Are Already Accounted For In the Cap-and-Trade Regulation.

Beginning in 2015, natural gas suppliers were phased in as covered entities and therefore have a compliance obligation under the Cap-and-Trade program. The level of obligation is determined by "every metric ton of CO₂e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California."²⁰¹

Per the definitions in the Sections 95852(c) and 95811(c), "natural gas suppliers" is inclusive of the entities that serve fuel cell customers who choose natural gas as their fuel supply. This is further verified by CPUC inclusion of the compliance fee in natural gas supplier tariffs that outline charges passed on to end-users of natural gas and subsequent utility tariff adjustments:

²⁰¹ Cap and Trade Regulation, Section 95852(c)

“Suppliers of natural gas, including Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SOCALGAS), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Company (SWG) (collectively, the utilities), must comply with the Cap-and-Trade regulations.”²⁰²

“Consistent with D.14-12-040, the Preliminary Statements provide that GHG compliance costs would be collected from core and non-core customers... GHG compliance costs should be allocated between customer classes on an equal-cents-per-therm basis.”²⁰³

“PG&E was ordered to file this Tier 2 Advice Letter within 30 days of the effective date of the Decision to update PG&E’s existing transportation tariffs to include GHG costs in transportation rates.”²⁰⁴

Therefore, natural gas fuel cell emissions and obligation payments are captured upstream through the natural gas utility.

4. Removal of the Fuel Cell Exemption Will Disincentivizes a GHG Emissions Reduction Technology.

As discussed above, fuel cell technologies can displace higher GHG emissions sources on the grid. Customers also forego service from the electric distribution utility that receives a free allocation of allowances from the ARB for the benefit of their retail ratepayers. By directly regulating fuel cells as an emissions source under Cap-and-Trade, customers will pay for GHG costs they may otherwise avoid because the incumbent utility is required to use its freely allocated allowances for the benefit of its customers. This situation will create a disincentive for the lower emitting alternative to utility service – fuel cells, and may lead to the counterproductive result of increasing system GHG emissions.

In conclusion, the removal fuel cells from Section 95852.2 will be detrimental to fuel cell development in California.. Fuel cells reduce GHG emissions compared to system-wide GHG emissions. Under existing law, natural gas fuel cell customers will pay for GHG costs going back to 2015 through the gas transportation rates. The amendment to Section 95852.2(b)(2) will create a disincentive for customers adopting fuel cells and effectively require them to choose between paying GHG costs and subjecting themselves to the administrative requirements of the Cap-and-Trade for a lower-emitting resource or not paying GHG costs (or receiving a climate credit) for a more emissions intensive product from the electric distribution utility. In order to encourage innovative distributed generation technologies, the ARB should not remove fuel cells from Section 95852.2. Bloom Energy appreciates the opportunity to submit these comments...

²⁰² Public Utilities Commission D.15-10-032, page 2

²⁰³ *ibid*, page 23

²⁰⁴ Pacific Gas & Electric Advice Letter 3651-G

In order to encourage the continue to drive GHG emissions reductions through the deployment of fuel cells, the Board should oppose the proposed removal of fuel cells from the list of emissions sources without a compliance obligation in the cap-and-trade regulation (Section 95852.2). The Board should adopt the following resolution:

WHEREAS, efficient distributed generation technologies, such as fuel cells, play an important role in the State's efforts to reduce GHG emissions,

NOW THEREFORE, the ARB shall release "15-day" proposed revisions to the Cap-and-Trade Regulation that continue to list natural gas hydrogen fuel cells as an emissions source without a compliance obligation. (BLOOMENERGY)

Comment:

We appreciate the opportunity to provide comments to the California Air Resource Board (known herein as 'Board') regarding the proposed amendments to the CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS REGULATION, particularly the amendment set forth in Appendix A: Proposed Regulation Order, Section 95852.2(b)(2), which removes the compliance obligation exemption on emissions from natural gas hydrogen fuel cells. Lockheed Martin respectfully disagrees with the Boards intention to eliminate the aforementioned exemption. Natural gas hydrogen fuel cells efficiently and electrochemically convert fuel into low-carbon, baseload electricity. Greater energy efficiency means less fuel consumed to produce the same output of electricity, and that lower fuel consumption corresponds to fewer CO2 emissions. Even when compared to advanced centralized combined cycle gas turbine power plants equipped with the best available control technology (BACT) — the US EPA's benchmark — natural gas hydrogen fuel cells delivers a lower CO2 footprint due to higher electricity efficiency.

Companies like Lockheed Martin recently invested in this technology with the understanding that the Board would continue to include such emissions in the compliance obligations (exemptions) of Section 95852.2. We invested significant money into the design and purchase of the capital equipment. We have also devoted substantial time into the operation and maintenance of the equipment to maximize efficiencies. All of these actions were completed under the assumption of regulatory relief from the Cap and Trade program.

For the reasons outlined above, Lockheed Martin recommends that the Board retain the language in Section 95852.2(b)(2). By retaining this language, the regulated community will be able to recognize the existing benefits (investments) in clean electricity producing technology, while potentially investing in future cleaner technologies. At a minimum, the Board should consider retaining the exemption and offering a compliance date of no less than 3 years for newly installed fuel cells. This would enable existing sites with fuel cells to fully recognize the benefit of their investments, while providing time for new projects to evaluate the benefits of the investment. (LOCKHEED)

Comment:

Thank you for the opportunity to comment on the staff proposal to reverse the treatment of fuel cells under the current Cap-and-Trade Program. Bloom Energy is one of 5 stationary fuel cell companies that are operating today in California.

Fuel cells are non-combustion technology. We convert fuel, either biogas or natural gas, electrochemically into energy. By doing so, we achieve GHG reductions, criteria air pollutant reductions, and do not use a lot of water. So there's a lot of co-benefits to the use of fuel cells.

Since the Cap-and-Trade Program began, ARB has recognized those environmental benefits and the energy system benefits of fuel cell technologies, and accordingly has not imposed a direct compliance obligation on fuel cells -- or their customers. Sorry, fuel cells or the customers.

Instead, fuel cell customers will see a GHG price signal, and are a part of the Cap-and-Trade Program through the inclusion of the natural gas sector in the program. Per the definitions of the program, natural gas suppliers is inclusive of the entities that serve fuel cell customers who chose natural gas as their fuel supply.

This is further verified by the CPUC inclusion of the compliance fee in natural gas supplier tariffs that our customers use. Therefore, natural gas fuel cell emissions and obligations payments are already captured upstream through the natural gas utility.

Further, the removal of fuel cells from the list of emission sources without a compliance obligation will have the unintended consequence of discouraging this technology, and the State will forego the net reduction of GHG emissions attributable to fuel cells.

In order to encourage innovative GHG-reducing distributed generation technologies, the ARB should retain the existing treatment of fuel cells in the Cap-and-Trade Program. (BLOOMEN2)

Comment:

Since the Cap and Trade Program began, the ARB has recognized the environmental and energy benefits of fuel cell technologies and, accordingly, has exempted their GHG emissions from compliance obligations under the Program. Emissions from natural gas fuel cells are included in Section 95852.2 "Emissions Without a Compliance Obligation." On page 132 of the Staff Report, a strikethrough appears on "emissions from natural gas fuel cells," recommending that natural gas fuel cells will no longer be exempt. This exclusion of fuel cells is contrary to California state policy objectives for a sustainable, low-carbon future and precedents that show that the benefits of fuel cells are directly in line with AB32, to wit:

1. GHG Reducing Technologies. Fuel cell systems are fuel flexible and can operate on biogas, hydrogen, or natural gas and, utilizing any of these sources, fuel cells reduce both GHG and criteria air pollutant emissions (e.g., NOx). Power generation produced

through natural gas combined cycle (NGCC) power plants meets the majority of electricity demand, but with the concomitant emission of criteria pollutants and efficiencies limited by heat engine constraints. Alternative and emerging clean high-efficiency fuel cells achieve low emissions of GHG and virtually zero emission of criteria pollutants. When using natural gas, fuel cells reduce both GHG and criteria pollutant emissions compared to generation from the current grid.

2. Pathway to 100% Renewable. Fuel cells have highly dynamic dispatch capabilities to (1) manage the diurnal variation, constrained capacity factor, and intermittencies associated with solar and wind power generators, and (2) increase the maximum penetration of renewable resources that can be accommodated in the utility grid network. These capabilities will result in additional GHG reductions through the integration of renewables. Over 30% of the power generated by fuel cells in California is already produced from biogas.

3. Precedent. Recognizing the superiority of fuel cell technologies in reducing criteria air pollutants and GHG emissions, the South Coast Air Quality Management District (SCAQMD) policy exempt: natural gas fuel cells and their supplemental heaters. from the requirement of written permits Rule 219 and Rule 222 "Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II" (May 13, 2013). Additionally, the CARB DG certification program requires manufacturers of electrical generation technologies- that are exempt from district permit requirements- to certify their technologies to specific emission standards before they can be sold in California. Stationary fuel cells are providing power, heating and cooling in California and the SCAQMD territory today, and are recognized as well suited to provide the required clean, high-efficiency 24/7 load-following power generation resource with virtually zero emission of criteria air pollutants. reduction of GHG emissions and no net water demand.

4. Fuel Cells are Critical to the Energy System. To meet the demands of the next-generation grid, stationary fuel cells systems are (1) being developed and deployed with requisite load-following attributes, (2) operate on hydrogen as well as natural gas and biogas, and (3) developed to integrate with a gas turbine engine to create a "hybrid" power generator with remarkably high efficiency. Simply stated, stationary fuel cells are (1) a key resource, along with storage, required to manage and enable a 100% renewable grid, and (2) a perfect match to hydrogen energy storage in providing the ideal means for converting massive amounts of renewable fuel into electricity.

Fuel cells uniquely create value as a grid resource to provide firm capacity, the most valuable type of distributed energy resource, with respect to deferring future grid investments and benefiting both the regional transmission system and the local distribution system. Firm capacity (i.e., 100% or near 100% availability) is available day and night, rain or shine, and wind or calm without the additional need for forecasting, planning, or storage. This adds resiliency, reliability, stability, and value

to both the transmission and distribution systems, and these benefits translate directly into a more rapid transition to a 100% renewable grid.

The proposal to subject fuel cell customers to the Cap and Trade Compliance Mechanisms sends a market signal to customers that they will have limited choice in how to best and most economically meet their environmental objectives and local energy needs. Fuel cells are GHG reducing technologies that can serve both onsite and utility scale generation with negligible criteria air pollutant emissions. They are a critical tool to reduce GHG emissions from the State's energy sector and have a positive, direct public health impact on communities with significant exposure to air pollution. These attributes are consistent with the mission of the ARB and legislative direction through AB 32.

The NFCRC works with Bloom Energy, Doosan Fuel Cell America, Fuel Cell Energy, GE-Fuel Cells, and LG Fuel Cell Systems, Inc. These companies, and the additional undersigned stakeholders, including South Coast Air Quality Management District (SCAQMD) staff, request the continued inclusion of natural gas fuel cells as Emissions Without a Compliance Obligation in Section 95852.2 in the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation.

(NFCRC)

Response: The commenters request that staff reverse its proposed amendment to delete the exemption for emissions derived from a natural gas-powered fuel cell. ARB staff declines to reinsert this exemption.

ARB notes that there are a number of advantages of fuel cells compared to other fossil fuel powered electricity generation, including zero to near zero criteria air pollutant emissions and high electrical efficiency. ARB staff believe that existing policies capture and account for each of these advantages without the need to specify an exemption in the Regulation. Generally, fuel cells receive incentives from local air districts by being exempt from permitting due to such sources having near zero criteria air pollutant emissions. The high electrical efficiency means less fuel and GHG emissions per unit of electricity, and thus, the unit will incur savings on the fuel and GHG compliance costs.

The amendments to the Regulation remove a number of exemptions with the goal of treating all GHG emissions the same. The removed exemptions include the above mentioned emissions from fossil fuel powered fuel cells, waste-to-energy facilities, and high and low bleed pneumatic devices.

Being covered in the Program is not an indication of environmental performance and does not negate a company's goals of sustainability, environmental leadership, or being "green." The Program covers numerous facilities that have implemented sustainability actions (e.g., installing large renewable energy

generation or electric vehicle charging stations, LEED-certified buildings) or are otherwise taking steps to reduce their GHG emissions.

Qualified Export Exemption

C-1.12. Comment:

Eliminating Qualified Export and Natural Gas Fuel Cell Exemptions

We support the elimination of the qualified export (QE) exemption. As staff's analysis shows, the QE exemption has operated as a loophole that needs to be closed.²⁰⁵ (NRDC)

Response: Thank you for the support.

C-1.13. Comment:

Qualified Export Adjustment Is Needed

ARB Staff proposes to eliminate the qualified export (QE) adjustment to imported electricity. The QE adjustment is a deduction to a compliance obligation on a megawatt-hour-basis to electricity that is exported out of California in the same hour as electricity imported into the State by the same electric power entity. This provision is currently in the regulation in an effort to calculate a reduction in compliance obligation associated with electricity that was not generated in California and did not serve California load (generally called wheeling of electricity). Staff proposes to eliminate the QE adjustment because over the first compliance period, there was a 50 percent increase in the use of the QE Adjustment. Staff's conclusion is that the QE adjustment reflects a change in scheduling and transaction procedures in order to lower GHG compliance obligations and not wheeling transactions. However, Staff's conclusion has not been supported by any analysis and would artificially increase California measured emissions for wheeled power. Power that is not generated in California and does not serve California load should not be subject to a GHG compliance obligation; the Board should reject the proposed change in regulation.

The change is purported to be based on a study by Staff that has not been released to the public, so it is not clear whether ARB Staff accounted for the expansion of the CAISO to include a Nevada electric cooperative, Valley Electric Association (VEA), during the first compliance period. This non-California entity may have increased the use of the QE Adjustment through scheduling and transaction procedures in order to eliminate GHG compliance obligations, but it is a correct use of the QE adjustment since VEA is not in California. Power that is wheeled through California, that was not produced in California nor consumed in CA, should not increase California's measured GHG. If the change in the use of the QE Adjustment was not due to increased wheeling and the addition of VEA, Staff should propose a solution that will not eliminate wheeling

²⁰⁵ ISOR at 54 (noting that over the first compliance period there was a 50 percent increase in QE adjustments while imported electricity emissions decreased over the same period).

power through California and will not incorrectly place a GHG compliance burden on VEA customers.

SDG&E Recommendation: The Board should reject proposed changes in section 95802 deleting the definition of qualified export should be rejected as should the deletion of the QE Adjustment in the compliance obligation in section 95852 (b)(1)(B). (SDGE)

Comment:

CARB should quantify electricity imports on a net interchange basis

The cap and trade and reporting regulation do not currently treat electricity transmitted through the state consistently; in some cases power transmitted through the state is not assigned an import obligation, while in other cases it is. CARB's proposal to eliminate the qualified export adjustment (QEA) after 2020 would further exacerbate the disparate treatment.

Consider three difference scenarios where an entity uses the CAISO system to move power from the California Oregon Intertie (COI) to Eldorado to serve load in Nevada:

1. An entity schedules a 50 MWh wheel-through in the CAISO from COI to Eldorado,
2. The EIM dispatches 50 MWH from an EIM participating resource in PAC west to serve a load imbalance in NV Energy, and
3. An entity submits an import bid at COI for 50 MWH in the day-ahead market and an export bid for the same interval at Eldorado. Both bids are awarded.

In each scenario, the dispatch and power flow through the state is identical and does not reflect any increase in electricity consumption by California. However, CARB's current cap and trade regulation treats the three scenarios differently. Under scenario one, the 50 MWH is reported as a wheel, but not assigned a carbon obligation; under scenario two, the 50 MWH is not reported and not assigned a carbon obligation; under scenario three the 50MWh is reported as an import and export, with a carbon obligation assigned to the import.

CARB's assignment of an import obligation for the third scenario is problematic for two reasons. First, it does not reflect actual electricity that serves California load. The statutory framework for emission obligations in Assembly Bill (AB) 32 directs CARB to account for all electricity *consumed* in the state. In all of the above scenarios, California's consumption of electricity is unchanged, as the import at COI is balanced by an export at Eldorado. The EIM dispatch algorithm and regulation's provisions for wheel-throughs appropriately result in the export flow being netted against the import flow. However, because the regulation currently only allows for a limited netting via the QEA for power scheduled via the day-ahead market (and CARB proposed to eliminate the QEA provision), the accounting would inappropriately attribute 50 MWh as being consumed in the state. The over-statement of consumption will be exacerbated in the

future as more and more solar is added within the CAISO footprint, and California becomes a net exporter in certain hours: E-tag schedules may still show imports into California to reflect utility contracts and RPS obligations, even in conditions where net imports are negative.

Second, the disparate treatment of power flows that are dispatched through EIM versus other CAISO markets may alter incentives for entities to participate in these markets. If an entity is not assessed a carbon obligation for electricity transferred through the state in the EIM market, but does in the CAISO markets (or in a regional ISO in the future), this could discourage participation in the CAISO markets.

- WPTF supports elimination of the QEA, but recommends that CARB modify its regulation to account for the quantity of power consumed in the state on a *net-interchange* basis for all CAISO markets. This would require a change to how the quantity of imported power is calculated for imports via the CAISO markets:
- CAISO would calculate the ratio of net imports to final scheduled imports, exclusive of EIM, for each hour²⁰⁶ and provide this information to scheduling coordinators and to CARB.
- The cap and trade and reporting regulation should be modified to provide that the calculation of MWH of electricity imported via the CAISO markets be adjusted by the ratio of net to scheduled interchange in each hour.

In preparing annual reports, Electric Power Entities would multiply the net import ratio for each hour by each scheduled import for that hour, so that each import (specified and unspecified) would be reduced by the same amount.

This approach avoids the need to net particular electricity exports against particular imports or to net emissions associated with exports, but instead simply corrects the quantity of imported power to match California load. If discussions regarding GHG accounting in the EIM and regional ISO (see comments below) result in changes to how import flows are assigned to specific resources, then such an approach could also be considered for determining which scheduled imports actually serve load in the CAISO markets. (WPTF)

Response: The qualified export adjustment was included in the original Regulation, and at that time staff indicated that it would monitor and analyze the effects of the QE adjustment to determine if gaming and emissions leakage were occurring (FSOR to the 2010 Regulation). The QE adjustment was developed in an effort to calculate a reduction in compliance obligation associated with simultaneous exchange

²⁰⁶ Quantification of this ratio could be done on a more granular basis. We believe that an hourly interval would provide for sufficient accuracy and conform with CARB's current practice for reporting of schedules on an hourly basis.

agreements for electricity that did not actually serve California load; however, it has been more extensively used than expected.

First, it is important to point out that imports and exports must be separately reported under MRR to ensure we account for emissions from the generation source, even under exchange agreements, if those exchanges are not simultaneous. In addition, electricity that is wheeled through California must be separately reported. Electricity wheeled through California is electricity that passes through California, but with a source and sink outside of California as listed on a single e-Tag. The requirement to report wheeled electricity as separate from imported and exported was included in the 2010 MRR “as a data quality assurance measure” (2010 MRR ISOR, page 166).

QE adjustments are simultaneous exchanges, where electricity is imported and exported by the same PSE in a given hour, but documented on different e-Tags. Staff believes that a broad methodology has been applied based on simply having an import and export in the same hour with no determination of whether there was a simultaneous exchange agreement in place, and with no determination of whether the combined import and export reasonably represented a “virtual” wheeling of electricity rather than simply imports and exports that coincidentally occur simultaneously.

Staff noted in the 2010 Cap-and-Trade Regulation FSOR that staff would monitor implementation of the QE Adjustment to determine whether adjustments should be made. Over the first compliance period, there was a 50 percent increase in QE adjustments while imported electricity emissions decreased over the same period. This increase in the use of the QE adjustment, with minimal evidence that the inclusion of the QE adjustment is needed to ensure proper alignment of market incentives has led staff to propose the removal of the QE adjustment after 2020. Staff’s intent in removing the adjustment is to ensure that emissions leakage is minimized to the extent feasible as required by AB 32. In addition, staff believes that doing so will not affect the behavior of the electricity market, and, given the small amount of QE adjustment that has been reported under MRR, will have only a relatively minor effect on the compliance obligation of a small number of entities.

Staff disagrees that the three scenarios laid out by WPTF lead to “dispatch and power flow” that are identical. In the first scenario, ARB observes that the transaction could be a wheel or an export under MRR depending upon the location of the source. The second scenario seems to be theoretical, since there is no real world basis to establish it. For example, there would be no CMRI (CAISO Market Results Interface) or CAISO OASIS data to support that the second scenario ever actually happened. This is really a feature of the CAISO bifurcated markets where specific supply is not tied to or associated with the service of specific demand or load. The third scenario combines two separate

transactions and one outcome. This is problematic for two reasons. First, imports and exports must be separately reported under MRR. Second, WPTF assumes that the 50 MW import from COI would be the source for the 50 MW export to El Dorado, and that the import would not sink to serve California load.

Staff disagrees with WPTF when it states that there is disparate treatment of power flows through EIM versus other CAISO markets, which may alter incentives for entities to participate in these markets. First, ARB notes that existing market design differences may warrant different treatment. For example, the demonstration of direct delivery is necessarily different for metered, tagged, and EIM deemed delivered imports, as a result of different market designs or industry practices. Regardless of the differences, proper GHG accounting can be achieved through the separate reporting of imports and exports. Second, ARB does not agree that the market designs and processes described would significantly alter incentives to participate in EIM because the proposed bridge solution in MRR, coupled with the anticipated EIM algorithm changes being designed by CAISO in the two-pass solution, will address many, if not most of the concerns raised.

In response to SDGE's comment about the basis of staff's analysis, the increase in QE adjustment is not affected by Valley Electric Association's reporting methodology, which bases covered emissions on electricity that serves California load. In addition, the removal of the QE adjustment does not remove the requirement to report and track wheeled electricity in California. MRR already accounts for this through the requirement to report wheeled electricity. Electricity wheeled through California does not incur a compliance obligation.

Food and Beverage Fermentation Exemption

C-1.14. Comment:

Section 95852.2 – Emissions without a Compliance Obligation

Ag Council and AECA support the addition of #13, "Carbon dioxide from fermentation that occurs during the production of food and beverages." This language reflects the variable nature of the fermenting process, and we support providing this flexibility. (AGCOUNCIL)

Response: Thank you for the support.

C-2. Miscellaneous

C-2.1. Comment:

Support including fugitive methane emissions:

The issue of fugitive methane emissions is not directly addressed in this rulemaking except to the extent that natural gas consignment might incentivize a reduction in

fugitive methane emissions. EDF believes that ARB should begin taking steps to accurately account for fugitive methane emissions in the cap post-2020. In reality, all natural gas is already under the cap since importers of natural gas and natural gas extractors have compliance obligations under the cap. However, those compliance obligations are based on the emissions associated with combusting that natural gas. When that natural gas is leaked from a pipe, for example, as methane, the greenhouse gas impact associated with that now fugitive methane is much higher.

When ARB initially set the cap before compliance began, measurement techniques were not yet sophisticated enough to accurately account for fugitive methane emissions. However, major progress has been made since that time in the ability to measure fugitive or leaked methane. ARB will need to do a thorough evaluation of the steps necessary to include fugitive methane in the cap and an evaluation of the available data. Much of that discussion is beyond the scope of these comments but we look forward to engaging with ARB on this topic. We do encourage ARB to complete this effort in time to include fugitive methane in the post-2020 cap starting with the 2021 compliance year. (EDF)

Response: EDF, in arguing for the inclusion of fugitive methane emissions in the program, correctly identifies that this consideration is out of scope of the current regulatory amendments.

C-2.2. Comment:

Since the ARB Included the Natural Gas Sector in the Cap-and-Trade, It Should Revisit the Inclusion Threshold for Covered Entities.

The ARB should raise the threshold for small industrial entities now that the natural gas sector is covered under the Cap-and-Trade program. The administrative and transactional costs associated with cap-and-trade compliance can be burdensome and expose many small industrial entities to leakage risks when they are not accounted for in the EITE designations. These costs can be minimized consistent with the direction of California Health and Safety Code Section 38566 to achieve “cost effective emissions reductions.” The natural gas sector is better able to absorb these costs and minimize the carbon costs borne by end users because natural gas utilities can spread their administrative costs over a large number of customers and purchase compliance instruments in large volumes through competitive RFOs or through multiple bilateral agreements. In other words, the inclusion of a carbon price signal can be more cost effectively incorporated into the natural gas sector. Moreover, regulating industrial entities through the natural gas sector would still achieve the ARB’s emission reduction goals through the enforcement of a cap on total allocations to the natural gas sector and the inclusion of a carbon price signal in natural gas rates as required by CPUC Decision 15-10-032. In order to achieve “cost effective emissions reductions” as required by Health and Safety Code Section 38566, the ARB should raise the Cap-and-Trade

threshold to 50,000 metric tons of CO₂(e)/year in Section 95812 of the Proposed Amendments. (QUALCOMM)

Response: The commenter requests that the program inclusion threshold be increased from 25,000 to 50,000 metric tons of CO₂e (MTCO₂e) per year. Staff notes that such a change is outside the scope of the current regulatory changes.

Staff notes, however, that for the 2007 Mandatory Reporting Regulation, staff conducted inventory analysis and worked with stakeholders in setting reporting thresholds consistent with these requirements and considering Cap-and-Trade Program inclusion thresholds. We found that a threshold of 100,000 MTCO₂e would not capture many sources of interest for possible reductions, while a threshold of 10,000 MTCO₂e would capture many more sources (some unnecessarily) but would only increase the portion of the overall inventory captured by 2 percent. ARB selected 25,000 MTCO₂e as the most appropriate Cap-and-Trade Program inclusion threshold. Staff believes that operators with emissions at or above 25,000 MTCO₂e per year are the entities most likely to have the authority to plan and implement greenhouse gas reduction projects at these large stationary sources. Emissions at this level require fuel combustion of a magnitude associated with large industrial facilities (e.g., in excess of 450 million standard cubic feet of natural gas). A threshold of 25,000 MTCO₂e is comparable in size to other reporting programs, including the Regional Greenhouse Gas Initiative, the U.S. Acid Rain Program, and some sectors of the European Union Emissions Trading Scheme.

C-2.3. Comment

Additionally, PG&E recommends that primary facilities that pass through gas to downstream facilities should be treated as intrastate pipelines...

"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.²⁰⁷ 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

²⁰⁷ Pacific Gas and Electric Company. Re: February 24 Workshop on Amendments to the Mandatory Reporting and Cap-and-Trade Regulations. March 11, 2016.

pass-through gas for downstream 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. (PG&E)

Response: The comment primarily seeks changes to the definition of “intrastate pipelines” in MRR. That portion of the comment is outside the scope of this rulemaking. With respect to the portion of the comment concerned with the assigning of a compliance obligation (section 95852(a)(1) of the Cap-and-Trade Regulation), staff notes that this provision was not modified as part of this rulemaking, and therefore, the comment is outside the scope of the rulemaking.

C-2.4. Comment:

Another important point I would like to make is that I believe dairies should be regulated, since my community who are low income and people of color are the most affected. We deserve every right to be in a healthy living environment. (LEADERCOUNSEL)

Response: This comment is outside the scope of the current regulatory changes.

C-2.5. Comment:

NAIMA makes the following requests for clarification in the final regulations:...

NAIMA requests confirmation that opt-in entities can effectively opt-out. (NAIMA)

Response: The provisions in section 95813(g) of the Regulation that allow an opt-in covered entity to opt out at the end of a compliance period have not been changed. An opt-in covered entity that wishes to opt out of this program must apply to the Executive Officer by September 1 of the last year of a compliance period.

D. ELECTRICITY

D-1. Clean Power Plan (CPP)

Support for Use of Cap-and-Trade for CPP Compliance

D-1.1. Multiple Comments:

The Proposed Clean Power Plan Compliance Plan is Legally Adequate

Calpine supports ARB's proposed Compliance Plan for the Clean Power Plan ("Compliance Plan") as both reasonable and legally adequate. In particular, we believe the proposed backstop standards will sufficiently assure Clean Power Plan compliance in the exceptionally unlikely event that emissions from affected EGUs exceed compliance targets during any interim or final compliance period. CARB should, however, evaluate the effect on emissions from imported electricity in the unlikely event that the backstop is triggered and ensure that in-state generating resources are not disadvantaged and emissions leakage does not occur. Calpine also agrees with ARB that, in light of the fact that the Cap-and-Trade Regulation will continue to apply to both new and affected EGUs, ARB need not demonstrate that leakage will not occur by electing a new source CO2 complement. Recognizing these existing features and continued application of an equivalent compliance obligation to both new and affected EGUs, ARB's proposal to account for leakage by way of demonstration is appropriate. (CALPINE)

Comment:

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...

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...

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. (PG&E)

Comment:

WPTF supports inclusions of provisions for implementation of the Clean Power Plan (CPP) in the cap and trade program rules after 2020... (WPTF)

Comment:

Calpine strongly supports the Clean Power Plan and has, along with ARB, been defending the Clean Power Plan in litigation filed in the U.S. Court of Appeals for the District of Columbia Circuit. The Clean Power Plan follows a long history of regulation of the U.S. power sector under the Clean Air Act, both in recognizing the sector's unique interconnected nature and in relying upon the principles of least-cost dispatch to drive emission reductions. When fully implemented in 2030, the Clean Power Plan will ensure that carbon dioxide ("CO₂") emissions are reduced to 32% below 2005 levels from affected EGUs on a nationwide basis. These reductions formed the basis of the U.S. CO₂ emission reduction commitment taken to the 2015 Paris Climate Conference, and what allowed the United States to leverage similar reductions from other nations under the Paris Agreement that emerged.

The Clean Power Plan therefore stands as testament to the success of the Cap-and-Trade Regulation and reflects the fulfillment of one of ARB's primary purposes in proceeding with its implementation.²⁰⁸ By forming part of the factual predicate for the "best system of emission reduction" for existing sources under Section 111 of the Clean Air Act, the Cap-and-Trade Regulation is alone fulfilling the ultimate goal of AB 32 of "encouraging other states, the federal government, and other countries to act,"

²⁰⁸ See CPP, 80 Fed. Reg. at 64725, 64735, 64835-36 and 64887-88 (recognizing that the EPA considered California's experience in developing a GHG trading program in formulating the "best system of emissions reduction" for existing fossil fuel-fired electric generating units and in designing other elements of the CPP).

recognizing that “[n]ational and international actions are necessary to fully address the issue of global warming.”²⁰⁹

Calpine previously provided comments in response to ARB’s September 2015 discussion paper,²¹⁰ and thereafter provided comments on certain topics discussed in two December 14, 2015 presentations: “Regional and Linkage Considerations” and “Clean Power Plan & Cap-and-Trade.”²¹¹ In our comments below, we provide our support for numerous amendments proposed by ARB to streamline and improve market performance, as well as ARB’s proposed extension of the Cap-and-Trade Regulation beyond 2020 pursuant to existing statutory authority and as the state’s Clean Power Plan Compliance Plan. Finally, we offer a handful of discrete technical amendments aimed at improving clarity and implementation for regulated entities. (CALPINE)

Comment:

IETA strongly supports the use of California’s cap-and-trade program as the backbone of the state’s Clean Power Plan (CPP) State Implementation Plan (SIP). Enabling alignment of the market program’s structure – for both compliance periods and coverage – to meet CPP requirements will place California at the forefront of compliance with the future federal program. (IETA)

Comment:

MID supports the use of the Cap-and-Trade program as California’s means of demonstrating compliance with the federal Clean Power Plan (“CPP”). California has already invested in the Cap-and-Trade market-based program and should leverage its capabilities to ensure compliance with the U.S. EPA’s Clean Power Plan. MID suggests that ARB consider outreach with neighboring states to help them adopt mass-based trading programs that are capable of robust, two-way linkage with the California Cap-and-Trade program. (MODESTOID)

Comment:

SCE supports ARB plans to use the Cap and Trade Program to comply with the Federal Clean Power Plan. ARB Staff is proposing to use the post-2020 Program as the compliance demonstration mechanism for CPP. The proposed amendments would allow compliance with the Cap-and-Trade Regulation (as amended by this package) to allow electric generating units in the state to be in compliance with CPP as well. SCE supports this effort, and encourages the state’s show other states that a Cap & Trade

²⁰⁹ Health and Safety Code Section 38501(d).

²¹⁰ See Clean Power Plan Compliance Discussion Paper (Sep. 2015) (hereinafter, “Discussion Paper”), <http://www.arb.ca.gov/cc/powerplants/meetings/2015whitepaper.pdf>. Calpine’s comments on the Discussion Paper are available at: <http://www.arb.ca.gov/lists/com-attach/7-111dcompliance-ws-UTJUMwBtUnFQPwRq.pdf>.

²¹¹ These presentations are available at: <http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm>. Calpine’s comments are available at: <https://www.arb.ca.gov/lists/com-attach/24-capandtradeccplan-wsBmVTNAdqACMKZQRq.pdf>.

program like the one operating in California can satisfy EPA requirements and demonstrate equivalency with federal standards – hopefully spurring other states to follow California’s lead. (SOCALEDISON)

Comment:

Clean Power Plan: We support the architecture of ARB’s compliance plan to rely on the cap-and-trade program under a state measures approach, and support the conforming changes ARB’s proposes to align the cap-and-trade program with CPP requirements (including compliance deadlines, EGU coverage, and a federally-enforceable backstop mechanism) *[for more detail see comments on California’s proposed compliance plan for the federal Clean Power Plan]*. (NRDC)

Response: Commenters offer support for the core design decisions made in the Compliance Plan, including the use of the Cap-and-Trade Program as the core compliance structure. Commenters note that the state Program’s comprehensive coverage and stringent targets will support CPP compliance, model programs for other states, and support future linkages. ARB staff agree and appreciate the support.

Opposition to Use of Cap-and-Trade for CPP Compliance

D-1.2. Multiple Comments:

Do not commit California to continuing Cap-and-Trade through the Clean Power Plan. Since carbon trading cannot be verified, ensure that the Clean Power Plan power purchases are from sustainable, renewable power plants...

Do not use Cap-and-Trade (or carbon trading, offsets) for the Clean Power Plan. The Clean Power Plan must ensure power is generated from sustainable, renewable sources. (EJAC)

Comment:

The State Board may not rely on Cap and Trade for Compliance with the Clean Power Plan.

The ISOR reflects staff’s proposal to use the post-2020 Cap and Trade program as the compliance demonstration for the Clean Power Plan. ISOR at 12. Further, staff propose a state measures plan, which means that the Cap and Trade program will be used for compliance purposes but not itself be federally enforceable. ISOR at 22. The Clean Power Plan allows states to submit a “state measures” plan, but that plan must meet the same integrity elements as federally enforceable measures. 80 Fed. Reg. 64662, 64836/2 (Oct. 23, 2015). California must demonstrate “adequate legal authority and funding to implement the state plan and any associated measures.” *Id.*; see also 80 Fed. Reg. at 64848/3; 40 C.F.R. § 60.5745(a)(9). For the reasons set forth above in Section II, the State Board has no legal authority under state law to implement Cap and

Trade after 2020 and therefore may not use Cap and Trade as a means for compliance with the Clean Power Plan. (JOINTENVJUSTICE)

Comment:

Furthermore, we have signed comments with broader scope, including opposition to extending the use of Cap and Trade for compliance with the CPP. We do not support the Trading Plan for CPP because carbon trading places unjust burdens on low income communities and communities of color. Climate change solutions must protect all Californians, starting with those already overburdened by air pollution.

We support the request that CARB instruct its staff to prepare a compliance plan that does not include carbon trading, but rather reduces emissions in environmental justice communities. (GAIA)

Response: Commenters contend generally that Cap-and-Trade should not be used as part of the compliance plan, asserting that the Cap-and-Trade program places an unjust burden on disadvantaged communities and lacks a legal foundation. Instead, commenters assert that a compliance plan should be designed to use renewable power and reduce emissions in environmental justice communities. Staff did not make changes in response to these comments. Staff did not do so for several reasons. First, as detailed in response to 45-day comments J-2.1 and K-1.8, and pursuant to AB 32, and with the recent passage of AB 398, ARB has legal authority for the Cap-and-Trade Program, and it is clear that the Program itself does not place unjust burden on disadvantaged communities, especially when considered in concert with state and federal criteria and toxics control programs and strengthening improvements to those programs that are underway. In any event, however, commenters appear to omit the critical point that CPP targets are well above anticipated (and even current) emissions levels for facilities in California. This means that CPP compliance plans cannot, in themselves, reduce emissions for federal compliance purposes below these levels: California is already on track to comply. To the degree that further emissions reductions are appropriate – and ARB staff support continued efforts to reduce emissions throughout the state and, in particular, in disadvantaged communities – this is a state law matter that does not concern CPP compliance designs.

CPP Costs

D-1.3. Comment:

Clean Power Plan and Imported Electricity

The proposed amendments reflect ARB's proposal that the Cap and Trade program serve as the compliance program for the CPP if the stay of the regulation is lifted. Thus, consideration of the CPP's impact on out-of-state generation that is ultimately imported to California is of vital importance when vetting the proposed amendments as noted in

the Proposed Compliance Plan for the Federal Clean Power Plan²¹². ARB staff are proposing and recognizing that under the proposed CPP Plan, imported electricity will realize both the Cap and Trade compliance obligations under the proposed regulation and the compliance obligations from other states. This essentially doubles the compliance obligations for these facilities. SCPPA is concerned that ARB has not recognized or discussed the economic impacts on electric utility customers for those affected utilities, including many SCPPA members, which have must-take contracts with out-of-state fossil-fueled generating facilities. This may result in heavy cost burdens on California electric utilities, many of which serve disadvantaged communities. Because of this, SCPPA requests that ARB evaluate and address the cost burdens that may be faced by these utilities. (SCPPA)

Response: The commenter asserts that CPP compliance costs faced by generators in other states may be passed onto California communities if ARB does not account for these costs in its design of Cap-and-Trade compliance obligations for imported power. Staff did not make changes in response to this comment. Changes would be premature: ARB is obligated to account for imported power emissions and is continuing to do so. If other states develop CPP compliance plans, it will be possible to consider how these plans interact with California's system, and to assess, in a public process, whether any further amendments are appropriate. Because there are no other CPP compliance plans, amendments in this area cannot be based on this careful analysis, and so cannot be proposed.

Trading-Ready CPP Compliance

D-1.4. Multiple Comments:

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)

²¹² See California's Proposed Compliance Plan for the Federal Clean Power Plan, released August 5, 2016.

Comment:

WPTF supports inclusions of provisions for implementation of the Clean Power Plan (CPP) in the cap and trade program rules after 2020 and recommends that CARB include additional provisions to enable the California cap and trade program to be deemed 'trading-ready'. As we stated in previous comments, we believe that the additional changes needed to be trading-ready are minor, and would not in any way circumvent or prejudice the consideration of specific linkages as required by Senate Bill (SB) 1018.

We provide a more detailed discussion of these issues in separate comments on the proposed CPP compliance plan. With respect to the cap and trade amendments themselves, WPTF proposes 3 specific changes:

- Addition of a provision to allow electricity generating units (EGUs) to use allowances issued by other CPP states for compliance;
- Inclusion of the export/import adjustment parameter in the CPP backstop trigger; and
- Inclusion of a mechanism to adjust the quantity of CPP allowances under the backstop to account for any transfers of allowance between California and CPP states.

Addition of Provision to allow EGUs to use allowances issued by other CPP states

CARB has proposed new provisions in section 95943 that would enable entities to use compliance instruments issued by other programs pursuant to a 'Retirement-Only Limited Linkage' at such a time that the Board has approved such linkage.

WPTF recommends that CARB take the same approach to potential CPP linkages. Specifically, we recommend that CARB add language to section 95943 that would enable EGUs to use allowances issued by an external emission trading system to which the Board has approved a linkage under the CPP.

Inclusion of the import/export adjustment parameter in the CPP Backstop Trigger

To be trading-ready, the backstop trigger would additionally need only to include consideration of the effect of net export/import adjustment on aggregated EGU emissions. WPTF therefore recommends that CARB modify the proposed language for section 95859(d) to include reference to the import/export adjustment:

"By October 24 of the year after a compliance period ends, the Executive Officer shall compare the aggregate reported and verified emissions and assigned emissions for all affected EGUS for the compliance period, as modified by any allowance export/import adjustment, to the aggregate CPP backstop trigger established in Appendix D."

Mechanism to adjust the quantity of CPP allowances to account for trading with other CPP states

WPTF considers CARB's proposed backstop design that would require EGUs to comply with the broad cap and trade program and comply with an EGU-specific cap by also retiring CPP allowances, to be workable in the context of the broader California program. However, the proposed backstop design will require further modification to function if and when California's program is linked to other CPP trading programs.

If CARB approves linkage of the California cap and trade program to those of other CPP allowance trading states, then transfer of allowances between California and CPP states must be accounted through the allowance export/import adjustment. Because California would be operating as a state measures program, California's ongoing compliance with the CPP would be demonstrated by comparing glide path targets to aggregated EGU emissions, as adjusted by the export/ import adjustment.

If the backstop is triggered and in effect, California's compliance with the CPP would be demonstrated through individual EGU's retirement of EGU-only CPP allowances. (In effect, California's program would operate as an emission standard type program while the backstop is in place). The net allowance import/export adjustment would therefore not be applicable for tracking transfers during the backstop period. Instead, a mechanism would be needed to adjust the size of the CPP allowance pool to reflect transfers of allowances to and from other CPP states.

- Transfer of a California allowance by a California EGU to an EGU in another CPP state will reduce the quantity of allowances available in the overall cap and trade program, but will not reduce the quantity of CPP allowances available to California EGUs. CARB should therefore include a requirement that the transfer of allowances to a CPP state requires retirement of the equivalent quantity of CPP allowances by the transferring EGU.
- Similarly, acquisition of allowances from an EGU in another CPP state would result in additional compliance instruments for the EGU to comply with the broad program rules (thus freeing up allowances for use by other entities in the program), but would not increase the quantity of CPP allowances available for backstop compliance. CARB should therefore issue a corresponding CPP allowance for each allowance acquired by an EGU from another CPP state.

(WPTF)

Comment:

Encouraging the Air Resources Board to identify and pursue the necessary changes to the GHG emissions program to make it a trading-ready program under the Clean Power Plan (CPP). The complexity of managing multiple state carbon programs under the EIM or regional ISO underscores the benefits of linking western states programs where possible. Having consistent trading ready state CPP implementation plans will facilitate

least-cost carbon reductions for electric power ratepayers, align carbon price signals to generators and minimize emissions leakage. We appreciate the efforts made in this amendment process to make the California program CPP compliant and encourage you to identify and take the additional steps needed to make it trading-ready. (PGP)

Comment:

As the Compliance Plan is evaluated further, Calpine encourages ARB to continue exploring the possibility of incorporating trading-ready elements or otherwise amending the Cap-and-Trade Regulation to take advantage of the opportunities presented by the CPP to link with broader markets and thereby maximize market efficiency and opportunities for least-cost reductions. Such linkages may be particularly important in light of the expansion of the California Independent System Operator (“CAISO”) markets to include other jurisdictions within the western interconnection that may be subject to mass-based carbon prices as a result of the CPP. (CALPINE)

Response: Commenters assert that the Compliance Plan should be designed as formally “trading-ready” – a term used by U.S. EPA to indicate Compliance Plans that can automatically link with other states’ CPP Compliance Plans. Commenters also propose various policy mechanisms, including backstop designs, that ARB could employ if it were operating a linked, trading-ready plan. ARB staff did not make changes in response to these comments. Staff will continue exploring opportunities to link California’s program with programs in other jurisdictions, and to support western grid systems and GHG control programs that support low emissions power. However, at this juncture, only California has proposed a CPP Compliance Plan in this region. It is, therefore, premature to develop specific policy mechanisms for linking and trading with other Compliance Plans. ARB staff may propose such mechanisms if other Compliance Plans are proposed. Staff continue to engage with officials in other western states to discuss potential collaborations in this area, and appreciate that many stakeholders would support expanded linkages. Any such decision would be made after a full public process, accounting for all relevant legal requirements, and would be designed to ensure environmental integrity.

Flexibility in CPP Compliance

D-1.5. Comment:

ARB is proposing to use a “state measures” approach to demonstrate California’s compliance with the federal Clean Power Plan, which establishes guidelines for carbon emission reductions from electric generating units.²¹³ This will allow California to incorporate Clean Power Plan compliance into the Cap-and-Trade Program and MRR. However, this approach may potentially limit California’s ability to participate in a broader carbon allowance trading regime, if one is developed, across the Western

²¹³ Cap-and-Trade ISOR at 24.

Interconnection or nationally. California's potential to be isolated from a broader regional or national carbon market is likely to create seams issues if the western energy market develops into a regional organized market. As described above with respect to the EIM, the energy market is becoming more integrated to maximize the benefits of a regional market to integrate the region's increasing renewable resources. State-specific carbon policies such as California's, if imposed myopically, have the potential to hinder this modernization and integration and slow the transition to a less carbon-intensive future. Accordingly, PacifiCorp urges ARB to consider its Clean Power Plan compliance approach with this long-term regional vision in mind and, to the extent feasible, retain flexibility to ensure that California's energy and environmental policies are developed in concert. (PACIFICORP)

Response: The commenter urges California to maintain flexibility in the Compliance Plan design to account for the possibility of a regional or national carbon market. Staff did not make changes in response to this comment. As discussed in response to 45-day comment D-1.4, incorporated here by reference, it is premature to make policy changes at this time, in the absence of other regional Compliance Plans. However, both the Compliance Plan and Cap-and-Trade Regulation are designed to allow for potential future linkages, if appropriate conditions are met, and ARB staff continue to support regional collaboration as policy continues to develop.

Compliance Period Schedule Conditional on CPP

D-1.6. Multiple Comments:

EPA Clean Power Plan Implementation

Aligned Compliance Dates

ARB staff's proposed language in section 95840(d) would establish new, shorter compliance periods under the Cap-and-Trade Program to facilitate compliance with the federal Clean Power Plan (CPP). It is our understanding that ARB's intent with regard to this section is to only alter the current three-year compliance period structure of the Cap-and-Trade Program if the CPP is upheld on appeal in the federal courts, and even then only if EPA subsequently approves California's state plan submission. SCPPA supports the conditionality of these provisions and, in the absence of the CPP, would prefer to retain the current 3-year compliance period structure of the existing Cap-and-Trade Regulation. SCPPA requests that ARB confirm our understanding that the change in compliance period timing specified in proposed section 95840(d)²¹⁴ would not take effect if any of the following events take place:

²¹⁴ Proposed section 95840 also provides that if EPA has not approved California's plan for compliance with the CPP by January 1, 2019, (including the new timeframes for compliance periods specified in specified in section 95840(d)), then current timeframes will continue to apply. In this case, the fourth

- The CPP is vacated or remanded to EPA by a federal court (either the D.C. Circuit or the U.S. Supreme Court);
- The EPA voluntarily withdraws the CPP or issues subsequent regulations that supersede the CPP;
- Congress passes legislation that effectively stays, rescinds, or significantly amends the CPP; or
- The EPA disapproves California's CPP compliance plan in whole or in relevant part.

As written, section 95840 does not explicitly address what the Cap-and-Trade Program's compliance periods would be under circumstances other than approval or disapproval of California's plan. For example, the proposed regulation does not address the possibility of remand, regulatory revision, or legislative override of the CPP that would block or substantially delay implementation of the CPP program. SCPPA envisions that ARB would need to conduct additional rulemaking in the future to address the repercussions of these events. Although it may not be possible to specify all of the events that would prevent a new compliance schedule from taking effect, ARB should at least clarify in its Final Statement of Reasons that if any of these events occur, the proposed compliance dates in section 95840(d) would not apply.

In addition, SCPPA anticipates that in the event the CPP is upheld and subsequently goes into effect, a court or EPA may nonetheless push back the start date of the CPP due to delays caused by the current Supreme Court stay of the CPP. In the event that the CPP's deadlines are tolled and thus the start of the CPP program is extended beyond 2022, SCPPA urges ARB to maintain the 3-year compliance period structure of the Cap-and-Trade Program for as long as possible before adjusting the compliance period length to comply with the CPP. Such an approach will minimize any potential disruption that could result from changing the current compliance deadline schedule in order to align the federal and state programs. (SCPPA)

Comment:

Alignment of the Compliance Dates

While LADWP understands the purpose of ARB's proposal to shorten compliance periods to two years in the post-2020 period in order to meet CPP requirements, LADWP generally supports longer compliance periods in order to provide compliance entities with additional flexibility.

Therefore, LADWP supports ARB's proposal to condition those changes intended to align the Cap-and-Trade Regulation with the CPP on EPA approval of California's CPP

compliance period would start on January 21, 2021 and end on December 31, 2023, with each subsequent compliance period having a duration of three calendar years.

implementation plan. To the extent that the Cap-and-Trade Regulation is not serving as the basis for California's CPP compliance (such as if the CPP is vacated or in the highly unlikely event that California's plan is deemed unsatisfactory), LADWP recommends retaining the current three year compliance period structure of the Cap-and-Trade Regulation.

Similarly, in the event that the start of the CPP's compliance period is tolled by the Court of Appeals for the District of Columbia Circuit or the United States Supreme Court and extended beyond 2022, LADWP urges ARB to maintain the three year compliance period structure of the Cap-and-Trade Program for as long as possible. (LADWP)

Comment:

Change of Compliance Periods to comply with the Federal Clean Power Plan (CPP)

Air Products understands the need to develop a compliance plan that can be approved by US EPA to satisfy the CPP “interim compliance steps”, but shortening the Compliance Periods to two years for all covered entities creates an additional burden on sectors not engaged in electricity generation. Air Products asks ARB to consider alternatives, including:

- i. Retain the current 3-year compliance period interval (which will align with Ontario's cap and trade program) and negotiate with US EPA on an alternative compliance schedule that satisfies the CPP program intent.
- ii. Only impose the new Compliance Periods on the electricity generation sector
- iii. Allow for a transition into the new, shorter periods – specifically, define the Compliance periods as:

The fourth compliance period defined as a 4-year period, January 1, 2021 through December 31, 2024 (aligns with the first CPP interim step),

The fifth compliance period defined as a 3-year period, January 2025 through December 31, 2027,

The sixth compliance period as a 2-year period, January 1, 2028 through December 31, 2029, and

Subsequent compliance periods continue every two-years, thereafter. (AIRPRODUCTS)

Response: Commenters express concerns that CPP compliance periods may change due to ongoing litigation or U.S. EPA decisions, and express a preference for the current three-year compliance periods of the Cap-and-Trade Regulation. Commenters urge ARB staff to provide flexibility for these dates where possible, or to limit the date changes to only CPP covered entities. Staff did not make changes in response to these comments. As drafted, CPP requires compliance periods that are shorter than the current Cap-and-Trade compliance

periods, and on a somewhat different time schedule. ARB will continue to advocate for compliance periods that more resemble the current three-year cycle in the existing Cap-and Trade Program. Maintaining a unified market requires all covered entities to be governed by these compliance periods. Staff judge, consistent with the support of many commenters, that the benefit of unifying the state and federal programs outweighs these concerns with compliance period timing. Staff is aware of the continued federal debate over CPP timing and implementation. Staff believe that rigorous implementation, as soon as possible, is critical to reducing national power sector emissions. However, to the extent U.S. EPA revisits the timing of particular compliance periods, ARB staff will continue to advocate for appropriate flexibilities to ease program integration, and believe such flexibilities are appropriate under the federal Clean Air Act's cooperative federalism model. Staff have also designed the Compliance Plan to ensure that the compliance periods will shift only if U.S. EPA approves those components of California's Compliance Plan. Accordingly, staff have provided for some flexibility and will continue to seek improved alignment where possible.

Compliance Obligation for Emissions Regulated by Other Jurisdictions

D-1.7. Comment:

California EDUs rely on significant amounts of imported electricity from neighboring states. These out-of-state power sources serve a critical role in enabling EDUs to meet their obligations to provide reliable, cost-effective electricity to California's business and homes. If other states in the West implement the CPP by imposing limits on GHG emissions from generating facilities in those states, importers of electricity would effectively be required to "pay twice" for each ton of GHGs emitted: once under the California Cap-and-Trade Regulation, and a second time under the other state's CPP implementation plan.

This double-regulation of imported electricity would cause numerous problems, including:

- Higher ratepayer cost burdens;
- Limited flexibility to avoid double-regulation due to long-term contractual constraints;
- Negative impacts on California's local air quality by incentivizing increased in-state generation;
- Negative impacts on trade-exposed industries due to higher electricity cost that would result from double regulation; and
- Risks for California's ability to comply with the CPP if double regulation incents significant shifts from out-of-state generation to in-state generation.

Similar problems would occur if neighboring states, such as Washington, were to adopt stand-alone GHG regulatory programs that are designed to achieve state-specific GHG emissions reduction goals.

To solve the double-regulation issue, CARB should modify the compliance calculation for electricity importers in section 95852(b)(1)(B) of the Cap-and-Trade Regulation by adding an adjustment factor for electricity sources from facilities that are regulated under neighboring states' CPP implementation plans. With this modification, entities that import electricity from facilities that are regulated under a neighboring state's CPP implementation plan would not be required to surrender allowances for the same electricity under the California Cap-and-Trade Regulation.²¹⁵ The adjustment would not apply to unspecified electricity imports or imports from facilities that are not covered under the CPP. Although not specifically discussed in these comments, this proposed solution discussed below for addressing double regulation due to the CPP would also apply to address similar problems resulting from stand-alone state GHG regulatory programs to achieve state-specific GHG emissions reduction goals.

This adjustment is allowed under AB 32, and would be similar to other adjustments to the compliance calculation that are already included in the Cap-and-Trade Regulation. Therefore, ARB should implement this solution as one important component of its ongoing process to extend the Cap-and-Trade Regulation and in a manner that is coordinated with the State's CPP implementation plan.

The discussion below explains this solution in greater detail.

B. The Problem: Overlapping Regulation of Imported Electricity

Many EDUs in California rely on significant amounts of imported electricity from neighboring states. These out-of-state power sources serve a critical role in enabling EDUs to meet their obligations to provide reliable, cost-effective electricity to California's business and homes. For example, in 2014, nearly a third of the electricity used to serve ratepayers in California came from electricity that was generated outside of California.²¹⁶ Although LADWP and other EDUs have been divesting from high-emitting generating facilities in neighboring states, EDUs in California will continue to rely on significant amounts of fossil-fueled out-of-state generation to meet their service obligations and maintain affordable electric rates.

²¹⁵ Although this section focuses primarily on the double-regulation that would arise if a neighboring state establishes a mass-based CPP plan that imposes an allowance-holding requirement on affected fossil-fueled electric generating units, many of the same issues discussed in this section of the comments would also arise if neighboring states or EPA impose rate-based plans to comply with the CPP. This would occur because a rate-based plan would impose a requirement for affected generating facilities to hold emission rate credits to the extent that their actual CO₂ emissions were above the applicable CO₂ emission rate limitation.

²¹⁶ Cal. Energy Comm'n, Energy Almanac, Total Electricity System Power (2014) , [http://energyalmanac.ca.gov/electricity/total system power.html](http://energyalmanac.ca.gov/electricity/total%20system%20power.html).

GHG emissions from out-of-state generation are currently regulated by the California Cap-and-Trade Regulation. Under this regulation, electricity importers must surrender compliance instruments to account for the GHG emissions associated with the electricity they import. In the future, other states are expected to also regulate the same electricity under implementation plans adopted to comply with the federal CPP. When Arizona, Nevada, Utah, Oregon, and other states in the West implement the CPP, emissions associated with imported electricity will be double-regulated—once under the California Cap-and-Trade Regulation and a second time under each state's CPP implementation plan.²¹⁷

Imposing these overlapping regulatory obligations are problematic for a number of reasons:

- Higher Ratepayer Burden. In-state generation would face only one GHG regulatory obligation under the Cap-and-Trade Regulation; however, imported electricity would face two obligations—one imposed by California, and the second imposed under a neighboring state's CPP plan. Importers would therefore be required to pay the costs associated with two overlapping GHG requirements, whereas in-state generators would only pay the costs associated with the California Cap-and-Trade Regulation. This situation will create a strong, perverse incentive to shift power purchases from otherwise relatively low-cost imports to higher-cost in-state generation sources. (This incentive would occur even in cases where the GHG emissions associated with electricity production at in-state and out-of-state generation are equivalent, such as between two natural gas combined cycle facilities.) Such shifting from out-of-state generation to in-state generation will lead to market inefficiencies and expose California consumers to higher electricity rates without necessarily achieving any incremental GHG reductions.
- Limited Flexibility to Avoid Double-Regulation. For many EDUs, such as LADWP, that own out-of-state generation, shifting generation from out-of-state to in-state energy sources may not be possible in the short- to medium-run due to contractual constraints, as well as health and environmental considerations in California. For example, entities in the South Coast Air Basin are already subject to stringent limits on ozone precursors and particulate matter. These requirements already place strict limitations on the amount of electricity EDUs in Southern California can generate. In LADWP's case, it will most likely not be feasible for LADWP to shift all of its fossil-fueled generation from out-of-state to California due to these constraints. As a result, LADWP and other EDUs may not

²¹⁷ As noted above, these comments focus primarily on the double-regulation that would arise if a neighboring state imposes a mass-based CPP plan that relies on a cap-and-trade-style approach for the electric sector. However, many of the same issues would arise if neighboring states or EPA impose rate-based plans to comply with the CPP given that a rate-based plan would impose a similar requirement for affected generating facilities to hold emission rate credits to the extent that their actual CO₂ emissions exceeded the applicable CO₂ emission rate limitation.

be able to avoid the added costs of complying with these overlapping regulatory obligations, and could be required to recover their costs by increasing its retail electricity rates. This increase in rates would not be associated with any improvement in environmental quality or increase in GHG reductions.

- Impacts on California's Local Air Quality. Even if some EDUs could shift from imported electricity to in-state generation to avoid the double-regulation, this shift could have major ramifications for local air quality. If in-state generation were to become more cost-effective than out-of-state generation due to double-regulation of imported electricity, in-state generation from fossil-fueled generators would be expected to increase due to this price signal. This increase in generation from in-state fossil-fueled generation could result in substantially greater emissions of air pollutants in California than would be the case without this double-regulation. Such a significant increase in emissions not only presents major compliance challenges to electric utilities in the South Coast, but also is likely to increase substantially the cost of compliance with these stringent emissions limits.
- Impacts on Trade-Exposed Industries. EDUs that are currently importing electricity are faced with two compliance options that would increase the cost of electricity. One option is to pay twice for GHG emissions attributable to imported electricity; the other would be for EDUs to shift their generation to relatively more expensive in-state generation in order to avoid the double-regulation of imports. Under either option, trade-exposed industries in California that are served by those EDUs would face higher electricity costs, which could exacerbate leakage and harm the economy by causing these industrial facilities to move out of California. This result would undermine the goals of AB 32.
- Risks for Clean Power Plan Compliance. California will be required to limit generation from in-state fossil-fueled generating units under the CPP. To the extent that California adopts a state measures plan to comply with the CPP, a significant shift from out-of-state generation (which does not impact California's ability to meet its emission goal) to in-state generation (emissions from which are counted toward California's CPP goal) could lead emissions from affected power plants to exceed California's CPP goal. This increase in in-state generation could result in the triggering of backstop measures, which could complicate the State's ability to comply with the CPP.

Because many California EDUs rely on imported power and expect to continue to do so in the future, this issue will become critical if the CPP goes into effect and the Cap-and-Trade Regulation is not revised to address this issue of duplicative GHG regulation. Therefore, it is crucial that ARB address this issue in the context of the upcoming rulemaking to extend the Cap-and-Trade Program.

Policy Design Principles for Addressing the Double-Regulation Issue

The following are four key principles that should guide ARB's development of any solution to address the double-regulation issue:

Principle 1. Avoid Double-Payment. California's consumers should not "pay twice" for each ton of carbon dioxide emissions attributable to the imported electricity that they consume.

Principle 2. Avoid Economic Inefficiency. The State should avoid imposing economically inefficient incentives for electric utilities in California to limit their use of imported electricity.

Principle 3. Provide Flexibility. The GHG regulation of imported electricity should be flexible and account for major changes in neighboring state GHG regulatory programs over time.

Principle 4. Maintain Environmental Integrity. The environmental integrity of the California Cap-and-Trade Regulation should not be compromised under any GHG regulatory approach that is developed to address the double-regulation of imported electricity. Any solution to the double-regulation issue should ensure that California can continue to meet its state-wide GHG reduction goals.

The Solution: Modify the Cap-and-Trade Compliance Calculation to Adjust for Emissions Accounted for in Other States

1. The Rationale Behind the Cap-and-Trade Program's Electricity Importer Provisions

As ARB stated in the Initial Statement of Reasons for the 2010 Cap-and-Trade Regulation, AB 32 requires ARB to account for and reduce emissions from both in-state generation and electricity imports.²¹⁸ The electricity_ importer provisions in the Cap-and Trade Program were implemented to ensure that the Program would reduce GHG emissions associated with electricity generated out-of-state and imported to serve California load. At the time these provisions were implemented, neighboring states did not regulate GHG emissions from generating facilities located outside California. Therefore, meeting AB 32's goal of reducing emissions associated with all electricity consumed in California necessitated using the Cap-and-Trade Regulation to set an overall tonnage cap on GHG emissions and impose an allowance-holding requirement to ensure that regulated sectors met the cap. Among other things, these requirements had the effect of providing a price signal to utilities to reduce the GHG emissions associated with the generation of electricity from out-of-state facilities serving California load.

2. The Rationale for Requiring Importers to Surrender Allowances Does Not Apply Where a Neighboring State Also Imposes Carbon Costs on the Same Generation

²¹⁸ See 2010 ISOR at 11-10 (citing Cal. Health & Safety Code § 38530(b)(2)).

As ARB has previously recognized, there is no need to impose a regulatory obligation on imported electricity if the GHG emissions associated with that electricity are already regulated under another GHG program. For example, ARB's 2010 Cap-and-Trade ISOR explained that if New Mexico or another state in the West were to implement a GHG reduction program, ARB would need to adjust the Cap-and-Trade Regulation to avoid double-counting emissions from imported electricity.²¹⁹ Where emissions associated with electricity imports are already regulated under another state's GHG program, the other state's program provides an incentive for generators to reduce emissions associated with imported electricity. Because these producers already face a GHG reduction requirement, there is no need for ARB to provide a duplicative incentive (in the form of the electricity importer allowance surrender obligation) that would effectively serve the same purpose as the neighboring state's GHG regulatory program.

In fact, AB 32 specifically requires ARB to consider and-to the extent possible-avoid duplicative regulations. ARB is directed by the statute to consult with the CPUC "in order to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements."²²⁰ ARB is also required to consult with other states to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.²²¹

Therefore, the need and justification for imposing a compliance obligation on imported electricity is not applicable in cases where the GHG emissions associated with the imported electricity are already being regulated. It is also inconsistent with ARB's statutory obligations to avoid duplicative regulatory requirements. On the other hand, continuing to regulate imported electricity when the emissions associated with this electricity are already being regulated by another state's program would cause a range of problems for California EDUs and their ratepayers (as described above in Section VI.B) while providing no additional environmental benefit.

3. ARB Could Eliminate This Double-Regulation by Modifying the Cap-and-Trade Compliance Calculation

To avoid double-regulating imported electricity, ARB should adjust the compliance calculation for electricity importers in section 95852(b)(1)(B) of the Cap-and-Trade Regulation. Specifically, ARB should adopt a new covered emissions adjustment factor to deduct from an electricity importer's compliance obligation any emissions for which the importer has already surrendered an emission allowance.²²² With this modification,

²¹⁹ See 2010 ISOR at II-43-44.

²²⁰ Cal. Health & Safety Code § 38501(b) (emphasis added). See also id. § 38561 (a) (requiring ARB consultations "to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner") (emphasis added); id § 38562(f).

²²¹ Cal. Health & Safety Code § 38564.

²²² The solution described in this section would also work in cases where a neighboring state imposes a rate-based CPP implementation plan. However, additional adjustments to the mechanism may be

entities that import electricity from facilities that are required to comply with a neighboring state's CPP implementation plan would not be required to surrender allowances for the same generation under the California Cap-and-Trade Regulation.

This covered emission adjustment factor would be limited to emissions associated with electricity imports from facilities that are covered by a neighboring state's CPP implementation plan. It would not apply to imports from facilities that are excluded from the CPP, such as simple cycle combustion turbines, units that are modified or constructed after the applicability date of the CPP, and certain other excluded facilities.²²³ (However, if a neighboring state decided to impose GHG reduction obligations on these facilities-e.g., by capping emissions from both new and existing power plants-these facilities would also be eligible for the covered emission adjustment factor.) This adjustment also would not apply to unspecified imports for which the generating source cannot be identified. Imports of unspecified power and imports from specified sources that are not covered by a neighboring state's GHG reduction requirements would continue to count toward an electricity importer's compliance obligation. Also, this adjustment factor would not alter the existing requirement under the MRR that electricity importers report emissions associated with all electricity imports.

4. To Ensure Environmental Integrity, ARB Would Need to Adjust the Cap to Account for the Imported Electricity Adjustment

In establishing the Cap-and-Trade Regulation emission budget, ARB first determined a desired emission level for covered sectors that would be consistent with AB 32's goal of reducing GHG emissions to 1990 levels by 2020.²²⁴ This determination took into consideration all GHG sources that would be subject to a compliance instrument surrender obligation under the Regulation, including those sources of GHG emissions

required to reflect the fact that the compliance burden under another state's rate-based plan is a requirement for affected electric generating facilities to hold emissions rate credits (and not allowances) to the extent that their actual CO₂ emissions exceed the applicable CO₂ emission rate limitation.

²²³ In certain limited cases, it is possible that a single facility would consist of some units that are covered by the CPP and others that are exempt. For example, a single facility site could consist of a mix of natural gas combined cycle units (which would be regulated under the CPP) and simple cycle turbines (which are exempt from the CPP). Under the MRR and WECC-wide e-tagging conventions, such a facility would typically be registered and reported as a single specified source. In this situation, MRR reports based on e-tags may not provide sufficient information to determine whether imported power was produced by a CPP-regulated unit at the facility or by an exempt unit. To address the potential for double-regulation in these cases, ARB could provide a partial deduction that reflects only the proportion of facility power generated by the CPP-regulated units. In this case, importers would only receive a deduction for the portion of the facility that is double-regulated, and would still be responsible for surrendering California allowances for the portion of the facility that is exempt from the CPP. Information on each unit's annual generation is already reported to EPA and ARB (this information is already being used by ARB to calculate average facility-wide emission factors). Therefore, it would be relatively simple for ARB to determine the proportion of each facility that would be eligible for the deduction.

²²⁴ See 2010 ISOR, Appendix E at E-5 (2010), <http://www.arb.ca.gov/regact/2010/capandtrade10/capv3appe.pdf>.

associated with electricity imports.²²⁵ As such, any significant changes to the scope of covered emissions sources will have an impact on the environmental integrity of the State's GHG reduction goals unless the overall cap established by the Cap-and-Trade Regulation-and therefore, the total number of allowances that are allocated and auctioned-is revised to reflect that certain imports are no longer subject to the GHG emission cap set for California.

Therefore, beginning in the year that the CPP goes into effect, ARB should reduce the size of the cap to account for the expected reduction in total covered GHG emissions due to the imported electricity adjustment described above.²²⁶ The GHG emission cap should be reduced prospectively in order to provide a clear price signal to market participants and to facilitate long-term planning. In order to determine the size of the cap reduction, ARB could utilize MRR data to determine the percentage of emissions associated with imports in a particular representative year (such as 2016 or 2020). Alternatively, ARB could model expected future emissions associated with imports under the current Cap-and-Trade Regulation and adjust the cap to account for the projected level of imported electricity that would likely be excluded from the cap.

One method for reducing the cap would be to reduce the allocation to EDUs by an amount that corresponds with the expected number of compliance instruments that will no longer be required to meet compliance obligations associated with imported electricity.

By reducing the cap to account for emissions that are regulated by other states but retaining the requirement to report emissions associated with imports, ARB can ensure that California will continue to be able to meet its obligations under AB 32 and SB 32 to reduce statewide GHG emissions (including those associated with imported electricity) by 40% below 1990 levels by 2030.²²⁷

E. Discussion of Legal Issues

While it would necessitate some changes to the current Cap-and-Trade Program regulations, addressing the overlapping regulation of imported electricity as outlined above is well within ARB's legal authority under AB 32.

1. AB 32 Does Not Require Electricity Importers to Surrender Allowances

AB 32 does not, by its terms, require the Cap-and-Trade Program- the "market-based compliance mechanism" authorized by AB 32-to regulate any particular source of emissions. Although AB 32 establishes a number of requirements for such a

²²⁵ (2008), <http://www.arb.ca.gov/cc/scopingplan/document/appendices volume1 .pdf>.

²²⁶ Reducing the size of the cap is not equivalent to changing the overall state-wide emission reduction goals established by AB 32 and SB 32.

²²⁷ Importantly, LADWP is not recommending any changes associated with the MRR. All electricity imports-and emissions associated with those imports-would continue to be reported.

program,²²⁸ California law contains no explicit requirement to include emissions associated with electricity imports in the Cap-and-Trade Regulation.²²⁹ Rather, ARB has relatively wide discretion in setting requirements for regulated entities in order to meet the GHG emission target specified by AB 32.²³⁰ Although ARB is required by law to adopt reporting regulations that "account for greenhouse gas emissions from all electricity consumed in the state, including . . . from electricity generated . . . outside the state,"²³¹ no provision of law requires ARB to impose an allowance surrender obligation for the emissions associated with imported electricity. ARB can continue to require entities to account for GHG emissions attributable to imported electricity without also requiring that importers surrender allowances for the GHG emissions associated with those electricity imports.

The Cap-and-Trade Regulation is not the only policy that ARB may consider when adopting regulations to comply with AB 32's emission reduction targets. AB 32 requires ARB to "adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions in furtherance of achieving the statewide greenhouse gas emissions limit,"²³² which is defined to include emissions from imported electricity.²³³ However, AB 32 does not require the market-based mechanism to be the only regulatory mechanism to meet this statewide emission limit.²³⁴ Rather, the Capand-Trade Regulation is only one component of ARB's overall approach to achieving statewide emission reductions.²³⁵ In determining how best to achieve the State's GHG emission goals, ARB has discretion to take into account the effect of regulations imposed by other states on emissions associated with imported electricity, including other states' plans to implement the carbon dioxide reductions required by the CPP. ARB could make a regulatory determination that the control of GHG emissions from imported electricity is already occurring under regulatory programs administered by neighboring states and, as a result, there is no need for California to adopt additional regulations that duplicate those regulations. As Section V. D of these comments explain, AB 32 requires ARB to avoid imposing duplicative GHG regulations.

²²⁸ See Cal. Health & Safety Code § 38562(d)(1)-(2)..

²²⁹ See Cal. Health & Safety Code §§ 38570-38574 (related to Market-Based Compliance Mechanisms);

²³⁰ Cal. Health & Safety Code § 38570(c) ("The state board shall adopt regulations governing how market based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits").

²³¹ See Cal. Health & Safety Code § 38530(b)(2) (emphasis added).

²³² Cal. Health & Safety Code § 38560.5(c); see a/so id. § 38562(a)

²³³ Id. §§ 38505(n) and (m).

²³⁴ Cal. Health & Safety Code § 38570(a) ("The state board may include in the regulations adopted . . . the use of market-based compliance mechanisms to comply with the regulations") (emphasis added).

²³⁵ See, e.g., ARB, 2030 Target Scoping Plan Update Concept Paper, at 2 (June 17, 2016), available at http://www.arb.ca.gov/cc/scopingplan/document/2030_sp_concept_paper2016.pdf (discussing the suite of State programs California is using to reduce GHG emissions).

In fact, ARB has already interpreted AB 32 in such a way as to permit it to take into account interactions between the Cap-and-Trade Regulation and complementary state energy policies, western electric market realities, and regional climate policies by reducing or eliminating compliance obligations for electricity importers under a number of specific circumstances.²³⁶ Therefore, it would be reasonable for ARB to conclude that regulating emissions from imports that are already being regulated in another state is unnecessary for achieving the statewide emissions limit and, furthermore, would impose a duplicative regulation on the utilities that rely on this imported electricity. Such a finding would be consistent with ARB's long-exercised legal authority.

In sum, while ARB must clearly adopt regulations that further AB 32's goal of reducing California GHG emissions-including emissions associated with imported power-it need not adopt regulations that impose duplicative requirements on importers.

2. The AB 32 Requirement to Minimize Leakage Can Be Addressed Without Double-Regulation of Emissions from Imported Electricity

In adopting regulations to establish the Cap-and-Trade program, ARB is directed to "minimize leakage," but only "to the extent feasible."²³⁷ The current requirement that importers of electricity surrender compliance instruments contributes to minimizing leakage from the electric sector that could occur if in-state generation shifts out-of-state.²³⁸ However, regulation of emissions from imported electricity under the Cap-and-Trade Regulation is not the only means of addressing leakage. Consequently, ARB's obligation to minimize leakage is not a bar to eliminating the double regulation of imported electricity.

It is important to note that AB 32 does not require the Cap-and-Trade Regulation to *eliminate* leakage. It merely requires ARB to implement feasible" measures to minimize" leakage. The approach outlined above-in combination with CPP regulatory requirements on out-of-state generators and complementary California policy-clearly

²³⁶ See Cal. Code Regs. tit. 17, § 95852(b)(1)(B) (related to the linked jurisdiction emissions adjustment); Cal. Code Regs. tit. 17, § 95852(b)(4) (related to the RPS adjustment); Cal. Code Regs. tit. 17, § 95852(b)(5) (related to the Qualified Export adjustment). Note that it would be appropriate and legally permissible to authorize adjustments consistent with those allowed for linked jurisdictions without requiring neighboring states to undergo formal linkage. Linkage permits the cross-border use of allowances and therefore automatically incorporates many design features of linked jurisdiction's GHG emissions trading systems such as price mitigation measures. See J. Jaffe, M. Ranson, & R.N. Stavins, Linking tradable permit systems: A key element of emerging international climate policy architecture, 36 *ECOLOGICAL* 789, 799-802 (2010), available at <http://scholarship.law.berkeley.edu/cgi/viewcontent.cgi?article=1910&context=elq>. As such, linkage appropriately requires a finding that the stringency of the linked jurisdiction's emissions trading system is commensurate with the California Cap-and-Trade Program. However, because the adjustments described in these comments are significantly more limited, they will not result in such effects on the California Cap-and-Trade market and thus may be implemented without the need to link with a neighboring jurisdiction.

²³⁷ Cal. Health & Safety Code § 38562(b).

²³⁸ See 2010 ISOR, Appendix D at D-620 to D-621, <http://www.arb.ca.gov/regact/2010/capandtrade10/capv2appd.pdf>.

meets this requirement. Because the adjustment factor described above would only apply to electricity imports from facilities whose GHG emissions are also being regulated under neighboring states' programs, there is little risk that entities would shift generation from California facilities to these regulated facilities in neighboring states.²³⁹ Existing requirements, such as the Cap-and-Trade Regulation's resource shuffling rules,²⁴⁰ SB 1368 emission performance standard, and the California RPS program will also provide additional incentives to continue reducing GHG emissions associated with out-of-state generation. Conversely, were ARB to fail to adopt a solution that avoids double-regulation of electricity imports, this policy could exacerbate leakage as industrial and commercial customers shift their businesses (and emissions) to states with lower electricity costs.

Therefore, the approach described in these comments, when combined with other state programs, represents a reasonable approach to minimizing leakage. This approach would avoid imposing duplicative costs on electricity importers and their customers, would avoid encouraging local industry to relocate its production and emissions out-of-state, and would be feasible to implement while minimizing leakage. To the extent ARB may be concerned with the potential for the solution described in these comments to lead to leakage, ARB can and should continue to monitor changes in the Western electricity market to determine whether any leakage is occurring. Further adjustments or policy approaches could be implemented if there is evidence of leakage.²⁴¹ This approach would be consistent to the one taken with respect to leakage under the initial Cap-and-Trade Regulation.²⁴²

In sum, unless changes are made to the current regulatory structure, the implementation of the CPP and other regional carbon policies could result in numerous difficulties for California ratepayers and industry that would not be justified by any improvement in the environment or public health. To address this issue, ARB should

²³⁹ Limitations on the applicability of the approach outlined above, including limiting the compliance obligation adjustment to specified sources that are specifically covered under a state's Clean Power Plan state plan-i.e., not simple cycle turbines or electric generators subject only to the New Source Performance Standards at 40 C.F.R. pt. 60 subpt. TTTT (the Carbon Pollution Standards rule for new and modified units)-will further limit the potential for leakage.

²⁴⁰ See Cal. Code Regs. tit. 17, § 95852(b)(2).

²⁴¹ One notable example could involve ARB applying a "discount factor" for the GHG emissions associated with imported electricity that would negate any incentive to shift emissions out-of-state. By allowing entities to deduct a portion of the emissions associated with imported electricity, ARB would reduce the extent to which these entities pay twice for the same emissions, while at the same time reducing the incentive to shift generation to out-of-state facilities. As a general matter, there are several possible approaches for setting the discount rate. One approach could involve in ARB setting the discount rate at a rate that reflects the relative stringency of California's program as compared to neighboring states' CPP targets. Another option could be a cost-based approach tied to the ratio of carbon prices in the two programs that would equalize any marginal economic incentives to shift generation to neighboring states.

²⁴² See, e.g., 2010 ISOR at IV-9 ("As part of implementation of the cap-and-trade program, ARB will monitor whether leakage is occurring. Should ARB find that leakage is occurring despite the safeguards in the regulation, ARB will examine what additional safeguards, possibly including border adjustments, should be implemented.").

modify the Cap-and-Trade Regulation to exclude emissions from out-of-state facilities that are already regulated under neighboring states' CPP implementation plans. This adjustment, which is consistent with ARB's obligations under California law, would maintain the environmental integrity of the Cap-and-Trade Regulation while resolving the problems associated with double-regulation of electricity imports. ARB should adopt this solution as part of the ongoing process to extend the Cap-and-Trade Program beyond 2020. (LADWP)

Response: The commenter asserts that CPP compliance costs faced by generators in other states may be passed onto California communities if ARB does not account for these costs in its design of Cap-and-Trade compliance obligations for imported power. The commenter asserts these issues could limit overall regional greenhouse gas reductions and unduly raise costs. Staff did not make changes in response to this comment. Changes would be premature, as explained in response to 45-day comment D-1.3, incorporated here by reference. ARB is obligated to account for imported power emissions and is continuing to do so. If other states develop CPP compliance plans, it will be possible to consider how these plans interact with California's system, and to assess, in a public process, whether any further amendments are appropriate. Because there are no other CPP compliance plans, amendments in this area cannot be based on this careful analysis, and so cannot be proposed. Nonetheless, staff appreciate the issues raised by commenter, and the proposed approaches to addressing them. Should another state importing to California move forward with a CPP Compliance Plan, staff will carefully consider these suggestions further before proposing any additional policy responses to such Plans.

CPP Backstop Design

D-1.8. Multiple Comments:

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. (PG&E)

Comment:

As discussed below, LADWP generally supports ARB's proposed backstop mechanism that would be triggered if California fails to meet its CO₂ reduction obligations under the CPP. Specifically, LADWP supports the establishment of a separate cap-and-trade program that would allocate free allowances to CPP-affected electric generating units (EGUs) under the backstop measure based on historic emissions. However, the comments below briefly outline LADWP's recommendations to ARB's proposed methodology for calculating the free allowances that would be allocated to each affected EDU under the backstop measure. In addition, LADWP supports ARB's proposal to allow affected EGUs to trade backstop emission allowances, but recommends that ARB allow for the interstate trading of CPP allowances under the backstop program.

Establishment of a Separate Regulatory Program to Implement the CPP Backstop

LADWP believes that in order to implement the CPP backstop, ARB should create and codify a wholly separate cap-and-trade system. This approach makes sense given the low probability of California ever triggering the backstop measure and in order to provide maximal flexibility in implementing the backstop. By establishing a separate parallel program, there is no need to make major changes to the design elements of the California Cap-and-Trade Regulation (such as the carefully crafted rules for emission trading and allocation of allowances). As discussed below, LADWP recommends specific changes to its proposal with respect to compliance with the CPP with respect to the allocation and trading components of the proposed backstop approach.

Methodology for the Allocation of Allowances

ARB proposes to use the calendar year immediately preceding the implementation of the backstop (described as "triggering compliance period" in the proposal) as the basis for allocating allowances to EGUs under the backstop program. While LADWP supports

ARB's proposal to calculate the backstop allowance allocations based on past emissions levels, we do not believe it is appropriate for ARB to use the year that immediately precedes its triggering when determining allowance allocations. Such an approach would reward the EGUs whose excess emissions caused the sector to exceed the CPP goal. This approach would also result in under-allocating allowances to those EGUs whose emissions had been reduced to well below the level that would be sufficient to meet the CPP goal without triggering the backstop.

LADWP recommends that ARB use a known, pre-CPP multi-year baseline of emissions as the basis for allocating allowances. ARB, for instance, could determine allowance allocation for its backstop program based on the average of affected EGU emissions from 2013-2015. Using this historic baseline would appropriately reflect the relative size and emission-intensity of different EGUs while avoiding the possibility of rewarding those EGUs that are most responsible for triggering of the backstop.

Using a multi-year period²⁴³ would provide a more representative baseline of normal operations than a one-year period, thereby lessening the impacts of unusual circumstances such as forced outages of EGUs, low energy demand, or low hydroelectric supply.

Interstate Trading of CPP Backstop Allowances

LADWP supports ARB's proposal to allow EGUs to trade CPP allowances within the backstop mass-based emission budget trading program. However, the backstop proposal would only permit the trading of allowances with other CPP-affected EGUs within California. LADWP believes that there is no reason for ARB to disallow the *interstate* trading of allowances.

LADWP believes that allowing interstate trading under the backstop program is good policy. Most California utilities, including LADWP, supply electricity to their customers from a mix of in-state and out-of-state generation sources, and so interstate trading of compliance instruments will reduce administrative costs. Interstate trading under the backstop program would promote more economically efficient decisions about generation throughout the West. Such flexibility and economic efficiency will be needed in a backstop situation because the very factors that could lead to excess emissions (unexpectedly high demand and unexpectedly low zero-emission generation) are also likely to complicate utilities' abilities to reduce in-state EGU emissions at a reasonable cost while maintaining reliability.

While it would be more flexible and efficient, interstate trading of CPP allowances under a backstop plan would not be complex; the allowances at issue will be EGU-only allowances created specifically for the CPP. Unlike with trading under state measures plans, the CPP authorizes trading of such allowances between affected EGUs that are subject to linked mass-based plans, and provides for one-for-one adjustments of states'

²⁴³ LADWP recommends using at least three full years of emissions data.

CPP mass-based goals to account for net flows of allowances between participating states.

Finally, there is no legal limitation or requirement that precludes ARB from establishing an interstate trading scheme for the CPP backstop program. The statutory requirements of SB 1018 only apply to the California Cap-and-Trade Regulation and other market-based programs to implement the goals of the AB 32 legislation.²⁴⁴ This limit, therefore, does not apply to the CPP backstop program because the backstop program is only implemented to assure compliance with federal requirements wholly separate from AB 32. So long as the federal backstop program is kept separate and independent from the Cap-and-Trade Regulation, ARB does not need to demonstrate compliance with SB 1018 requirements in order to authorize interstate emission trading under CPP backstop program.²⁴⁵

LADWP recommends that ARB design its backstop program to include authorization of EGUs to trade CPP allowances with other mass-based CPP state programs if the backstop is triggered, and to use allowances from these other programs to comply with California's backstop cap-and-trade requirements. (LADWP)

Comment:

Clean Power Plan Backstop

SCPPA generally supports ARB's approach to designing a backstop measure for compliance with the CPP, which is required for a "state measures" approach. In particular, SCPPA supports the creation of a separate Cap-and-Trade program only for CPP-affected electric generating units (EGUs), as well as ARB's proposal to allocate allowances at no cost (i.e., free allocation) to affected EGUs under the backstop based on historic emissions. SCPPA also supports ARB's proposal to allow affected EGUs to trade backstop emission allowances.²⁴⁶ SCPPA seeks clarity on whether a triggered backstop would remain in effect for the remainder of the program, or could potentially include a mechanism to revert back. However, SCPPA recommends that ARB make the following changes to the allocation and trading components of the backstop approach.

Changes to Allocation Component of Backstop. SCPPA recommends that ARB *not* use the most recent calendar year (described as "triggering compliance period" in the proposal) as the basis for allocating allowances to EGUs.²⁴⁷ Using the period in which emissions first exceeded California's mass-based CPP limits would have the

²⁴⁴ See SB 1018, codified at Chapter 39, Statutes 2012 (providing that the prerequisites for interstate trading only apply to a market-based compliance mechanism established pursuant to AB 32 and specified in Sections 95801 to 96022).

²⁴⁵ For this reason, LADWP recommends that the CPP backstop provisions be codified as a independent regulatory system, located in separate sections of the California Code of Regulations from the Cap-andTrade Regulation

²⁴⁶ See proposed § 95859(e)(6) (providing that backstop emission allowances —may ... be traded among entities that own or operate affected EGUs located in California and that are registered in the ProgramII).

²⁴⁷ See proposed § 95859(e)(5).

counterproductive effect of rewarding the very EGUs whose excess emissions caused the sector to exceed the CPP goal, while under-allocating allowances to those EGUs that have lowered their emissions to levels that may be well below a level that would be sufficient to meet the CPP goal without triggering the backstop.

Rather than using this proposed approach, ARB should instead use a known, pre-CPP baseline of emissions as the basis for allocating allowances. For example, ARB could use the average of affected EGU emissions from 2013-2015 as the basis for allocating allowances to affected EGUs.²⁴⁸ Using a historic baseline appropriately reflects the relative size and emission-intensity of different EGUs while avoiding the possibility of rewarding those EGUs that are most responsible for triggering of the backstop. In particular, it would prevent those EGUs – whose high emissions may have contributed most significantly to the triggering of the backstop – from being rewarded for their high levels of emissions by receiving a greater share of allowances than the EGUs that have taken measures to achieve significant reductions in their emissions.

In the alternative, if ARB decides to retain its current approach of using most recent emission years to calculate the backstop allowance allocation, ARB should consider using a longer averaging period (e.g., using the previous two compliance periods, or a minimum of three full years of emission data) in order to lessen the extent to which ARB rewards the biggest emitters under the backstop approach. In addition, the use of a multi-year period will provide a more representative benchmark of normal operations than a one-year period. Specifically, a multi-year period should minimize the distortions that would result from forced outages of EGUs, low energy demand, abnormally low hydroelectric supply, or other unusual circumstances during any given one-year period.

Changes to Trading Component of Backstop. While SCPPA strongly supports ARB's proposal to allow EGUs to trade —CPP allowances within the backstop Cap-and-Trade program, SCPPA also urges ARB to allow the *interstate* trading of allowances between California and other states' CPP plans with emissions trading programs. First and foremost, the statutory prerequisites of SB 1018 for interstate trading only apply to the California Cap-and-Trade Program and other market-based programs to implement the goals of the AB 32 legislation.²⁴⁹ *This means that the requirements of SB 1018 do not apply to the CPP backstop program given that ARB would establish the backstop program to assure compliance with the federal Clean Air Act (CAA) requirements under the final CPP rule, and not to implement the reduction requirements under the California Cap-and-Trade program and achieve the emission targets under AB 32. So long as the federal backstop program is kept separate and independent from the Cap-and-Trade*

²⁴⁸ If any affected EGUs were constructed or modified after January 1, 2013 but before the January 8, 2014 applicability cutoff date for the CPP, those EGUs' emissions during the historic baseline period could be estimated—for example, by assuming that these EGUs operated at an average capacity factor and emission rate the comports with the technology in use at the EGU

²⁴⁹ See Senate Bill 1018, codified at Chapter 39, Statutes 2012 (providing that the prerequisites for interstate trading only apply to a market-based compliance mechanism established pursuant to AB 32 and specified in Sections 95801 to 96022).

program, ARB does not need to demonstrate compliance with SB 1018 requirements in order to authorize interstate emission trading under CPP backstop program. To avoid any confusion on the relationship between the federal and state programs on this point, SCPPA recommends that ARB not codify the proposed backstop provisions in final Cap-and-Trade regulations specified in Sections 95201 to 96022 of Title 17 of the California Code of Regulations, as has been proposed. Rather, we suggest that ARB adopt the backstop program pursuant to regulations that are entirely separate from the Cap-and-Trade regulations and codify that program in a separate regulatory section of the California Code.

Second, allowing interstate trading under the backstop program makes good policy and economic sense. Most California utilities—including many SCPPA members—supply electricity to their customers from a mix of in-state and out-of-state generation sources. Although SCPPA supports ARB's selection of a state measures plan, we note that this selection—combined with other states' likely selection of other compliance approaches—will somewhat complicate these utilities' abilities to flexibly and cost-effectively balance in-state load and in- and out-of-state supply as demand and power availability fluctuates on a daily and seasonal basis. We recognize that authorizing interstate allowance trading between the AB 32 Cap-and-Trade Program and other states' EGU-only CPP programs may be complicated (although we urge ARB to continue working with utilities to enable such trading to take place). However, in the case of the backstop approach ARB has selected, such linkages between the California backstop Cap-and-Trade and other states' CPP Cap-and-Trade programs are likely to be both straightforward and beneficial for all entities.

Allowing interstate trading of CPP allowances between California's backstop program and other states' CPP programs will be straightforward because the instruments being traded between the California backstop program and other states' CPP programs will be EGU-only allowances created specifically for the CPP. The CPP explicitly authorizes trading of such allowances between affected EGUs that are subject to linked mass-based plans, and provides for one-for-one adjustments of states' CPP mass-based goals to account for net flows of allowances between participating states.

Finally, allowing EGUs in California to use CPP allowances issued by other EPA-approved programs, and vice versa, will also enhance the flexibility of California's backstop program while promoting more economically efficient decisions about generation throughout the West because it will allow California utilities to use CPP allowances obtained in California to satisfy obligations in other Western states, or to use allowances obtained in other state programs to satisfy the California backstop requirements. Such flexibility and economic efficiency will be needed most acutely in a backstop situation because the factors that could lead to excess emissions—e.g., greater-than-expected load growth or an extended outage of low-emitting generation (e.g., due to extended drought conditions in the Northwest or an extended nuclear outage)—are also likely to complicate utilities' abilities to reduce in-state EGU emissions

while meeting these utilities' obligations to serve California ratepayers reliably and cost-effectively. For these reasons, ARB should ensure its backstop program is "ready for interstate trading," including explicitly authorizing EGUs to trade CPP allowances with other mass-based CPP state programs if the backstop is triggered, and to use allowances from these other programs to comply with California's backstop cap-and-trade requirements (and vice versa). (SCPPA)

Comment:

As proposed, the backstop measure would require that all EGUs share in the responsibility to bring the state back into compliance should the state fail to meet the adopted CPP glide-path target identified in Appendix D of the Proposed Amendments and the backstop is triggered. Staff notes that such an approach is appropriate because there are no entity-specific caps in the CPP, as the federal limit is not EGU-specific. However, this proposal could result in some entities – namely those that fully met their compliance obligations under the Cap-and-Trade Program – bearing a larger burden for bringing the state into compliance with the CPP. The Staff Report and related CPP Report²⁵⁰ do not address how the backstop proposal avoids penalizing EGUs that met their full compliance obligation under the Cap-and-Trade Program through the mandate to surrender CPP compliance instruments if the backstop is triggered as set forth in proposed section 95859(c). If the shortfall in compliance can be attributed to specific EGUs, the backstop measures should also include – or at least CARB should further explore – options that would allow California to hold just those EGUs accountable. (NCPA)

Response: Commenters acknowledge that use of the backstop program is unlikely, but propose options to account for what they view as some unduly costly components of the program. Specifically, commenters argue that ARB should allocate backstop CPP allowances based on more than the prior compliance year, that ARB should allow interstate trading if the backstop is triggered, and that ARB should consider approaches that focus solely on "specific EGUs" that caused the target to be exceeded. Staff did not make changes in response to these proposals. Initially, staff agrees that it is exceedingly unlikely that the backstop would be triggered. As the CPP compliance demonstration shows, California EGU emissions are expected to be well below federal target levels in all years; even under the stress case, emissions are below federal levels. Thus, there is not an urgent need at this time to further manage costs of this backstop program, because it will almost certainly not be triggered. As to the specific suggestions: First, staff is not proposing that backstop CPP allowance allocation be based on a single prior year; instead, the regulation proposes to allocate based on emissions in the prior multi-year compliance period, consistent with commenters' suggestions. Second, it is premature to design a backstop system that links with other states' Compliance Plans at this time. No such Compliance

²⁵⁰ California's Proposed Compliance Plan for the Federal Clean Power Plan, dated August 5, 2016.

Plans exist, and ARB staff is unable to evaluate the rigor, design, and emissions control levels of these plans, and so cannot determine whether any specific plan is suitable for use in the backstop program, even if such separate linkages are legally permitted. Therefore, this suggestion cannot be implemented at this time. Finally, staff does not believe it appropriate to attribute backstop triggering to any specific subset of EGUs if the backstop is triggered; CPP is a sector-wide plan, and EGUs operate jointly in the grid, so such attributions are neither required nor appropriate. However, the backstop allocation methodology does provide some incentives for more efficient EGU operation, which addresses the underlying proposal's presumed intent of favoring lower emission electricity.

Definition of Affected Electricity Generating Units

D-1.9. Comment:

CARB's Regulations Should Define "Affected Electricity Generating Unit":

The proposed amendments frequently reference the term "affected electricity generating unit," particularly those amendments that address compliance with the Federal Clean Power Plan (CPP) in Section 95859. However, as far as IEP can tell, the proposed regulation does not contain a definition of "affected electricity generating unit" (EGU). While IEP understands that affected EGUs are defined in more detail in the Federal CPP, and other related CARB documents, it would be helpful to have "affected electricity generating unit" explicitly defined in CARB's final cap-and-trade regulations. For example, CARB may want to create a place in the upfront definitions section of the cap-and-trade regulations (Section 95802) that defines what an affected EGU is, consistent with the Federal CPP. Alternatively CARB could define "affected electricity generating unit" by citing to the specific sections of the CPP that define an "affected EGU." Currently, the proposed amendments seem to cite to the CPP in general without referencing the specific sections of the CPP that define an "affected EGU". This definition is fundamental to the program design going forward and should be referenced in the definitions section of these regulations, even if duplicative of other related regulations. Accordingly, IEP recommends including a definition of "affected EGU" in Section 95802 of the Proposed Amendments. (IEP)

Response: The commenter urges ARB to explicitly define "affected electricity generating unit." Staff did not make changes in response to this comment. The amendments to both the Cap-and-Trade Regulation and MRR implementing the Compliance Plan explicitly incorporate the affected EGU definitions set out in CPP. It is therefore not necessary to add a further definition.

D-2. Energy Imbalance Market (EIM) Imports

Accounting For Imported Electricity Emissions from EIM and Addressing Emissions Leakage

D-2.1. Multiple Comments:

CARB should develop consistent rules for attribution of imports and GHG emissions to California

CARB staff have raised concerns that the EIM algorithm is not completely accounting for GHG emissions associated with serving California load. To address this emission leakage, CARB proposes to calculate emissions leakage resulting from the EIM algorithm using the default emission rate and to assign an additional emissions obligation to California load-serving entities proportional to their EIM purchases. Additionally, CARB has proposed a new regulation that would exclude electricity imported via the EIM from the resource-shuffling exemption for short-term transactions.

WPTF agrees that the way the EIM is currently dispatching and assigning generation to CAISO load is distorting dispatch and in some cases results in increased emissions in the combined CAISO/EIM footprint. This appears to be a result of the EIM's displacement of California gas generation by a low-emission EIM imports, and the 'secondary dispatch' of a higher emission EIM resource. However, we do not support the proposed regulatory amendments because they will not fix the underlying problem associated with the EIM dispatch and the treatment of associated GHG emissions; instead they merely impose additional costs on California load-serving entities...

WPTF does not yet have a view on the correct solution, but notes that the distortionary effect of the EIM's current algorithm results from a combination of three factors: 1) the fact that the EIM optimizes for least-cost dispatch across the combined EIM and CAISO footprints, 2) the fact that carbon costs are not assigned uniformly to generation and dispatch within this footprint, and 3) the ability of the EIM algorithm to assign output from EIM resources to California even where the output of the resource was previously scheduled to serve load in an EIM entity. Changing any one of these three factors may result in GHG accounting that is more in line with the AB32 goals, but may have other consequences that make the solution impractical or politically unacceptable.

Many of the same GHG accounting issues that have arisen in the EIM will also need to be resolved for a regional ISO. To this end, WPTF suggest that GHG accounting in both the EIM and a regional ISO should conform to the following principles:

- Attribution of electricity to California load should not discriminate between California and external resources in providing opportunity to serve California load.
- The assignment of carbon compliance obligations to California resources and to imported electricity that serve California load should reflect actual emissions.

- EIM and Regional ISO market design should enable participating resources to accurately reflect carbon compliance costs in market bids for power that the resource offers to serve California load.
- Assignment of carbon costs and allocation of dispatched electricity to serve CAISO load in the market algorithm should not result in an increase in emissions in the market footprint due solely to displacement of generation from a California resources to a non-California resource.
- Market design should not impose carbon costs on resources that do not serve California load, nor on non-California load-serving entities.

Market design should eliminate the potential for double-counting of electricity that is reported to CARB as an import on the basis of e-tags (e.g. the CAISO day-ahead and fifteen minute markets) and electricity that is reported to CARB as an export allocation via the EIM.

WPTF recognizes that these are complex issues. It is because of this complexity and the potential for unintended consequences for the energy market, that WPTF urges that the CAISO and CARB to work jointly to address these issues within the energy market design. (WPTF)

Comment:

Executive Summary

The Energy Imbalance Market (“EIM”) jointly optimizes the real-time dispatch of physical generation resources across a footprint including Balancing Authority Areas (“BAAs”) within California and outside of it. By combining both the loads and the physical resources across an enlarged participating footprint, the EIM is able to reduce the cost of balancing load and generation in real-time. This real-time balancing function is of growing importance—and is an increasing challenge—as greater levels of renewable generation are added to the western grid. Renewable resources that depend on the availability of wind or sunshine introduce significant variability into the supply conditions that a grid operator encounters, requiring both increased adjustments to the output of dispatchable resources, and also improved operational planning to make sure sufficient dispatchable and flexible resources will be available if and when needed. The EIM provides a platform for participating BAAs to benefit from the California Independent System Operator’s (“CAISO’s”) sophisticated real-time tools, as well as from the diversity benefits of being part of a larger, coordinated, real-time system.

For these reasons, the EIM is often described as an important tool to facilitate renewable resource integration in the region. Indeed, the EIM is credited for reducing or avoiding the need to curtail California renewable output by identifying opportunities to export power from California, in turn reducing generation outside of the state (largely from fossil-fueled resources such as those that burn coal or natural gas). Without the EIM, such last-minute export transactions may not have occurred and California renewable production would have consequently been curtailed, while fossil fuel power

plants outside of California continued to produce electricity and greenhouse gas (“GHG”) emissions. In such circumstances, the EIM is undoubtedly providing environmental benefits in the form of significantly reduced GHG emissions in the region.

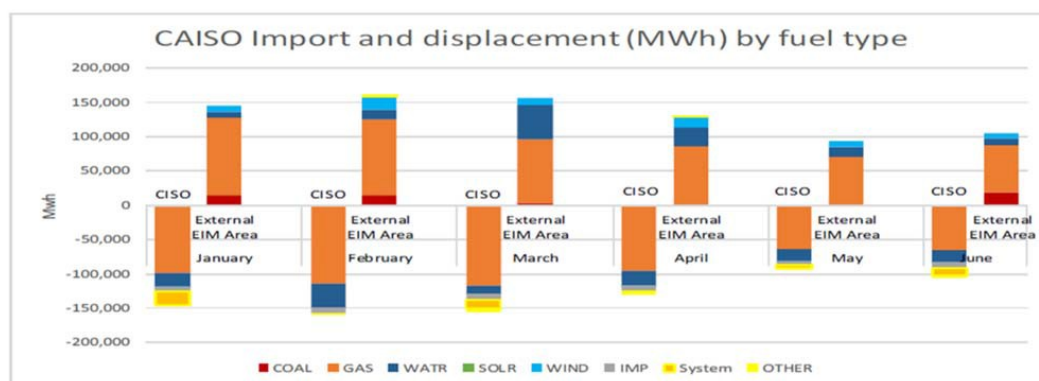
The EIM also is used to arrange for real-time imports into California from energy resources located outside of the state. Such imports—like all California electricity imports—are subject to the regulations of CARB, specifically the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (the “Mandatory Reporting Regulation” or the “MRR”) and the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (the “Cap-and-Trade Regulation”; the MRR and the Cap-and-Trade Regulation are collectively referred to as “CARB’s GHG Regulations”). CARB’s GHG Regulations reflect the requirements under California Assembly Bill 32 (“AB 32”) to (1) regulate GHG emissions at the production source for all electricity generation in the state; and (2) regulate GHG emissions for energy imported from resources outside of the state.

In these comments, Powerex addresses the manner that the EIM applies CARB’s GHG Regulations for imports serving load in California, and whether changes are necessary. While there may be significant environmental benefits associated with EIM exports out of California, that activity is not the subject of CARB’s carbon allowance framework²⁵¹, nor is it relevant to assessing whether EIM imports into California comply with CARB’s GHG Regulations or the environmental policy objectives of AB 32.

A review of the actual performance of the EIM raises significant concerns about the manner in which the GHG emissions of imports into California have been treated in the EIM dispatch and reported to CARB. The figure below shows the use of out-of-state resources in the EIM through June 2016, as prepared by the CAISO. The bars above the horizontal axis show the monthly EIM dispatch of out-of-state resources, by resource type, during intervals in which there were imports into California.²⁵² During those periods, it is clear that the EIM dispatched mostly natural gas-fired out-of-state resources (orange bars), with smaller amounts of energy produced by non-emitting hydro (blue) or wind (light blue) generation or by higher- emitting coal-fired generators (red).

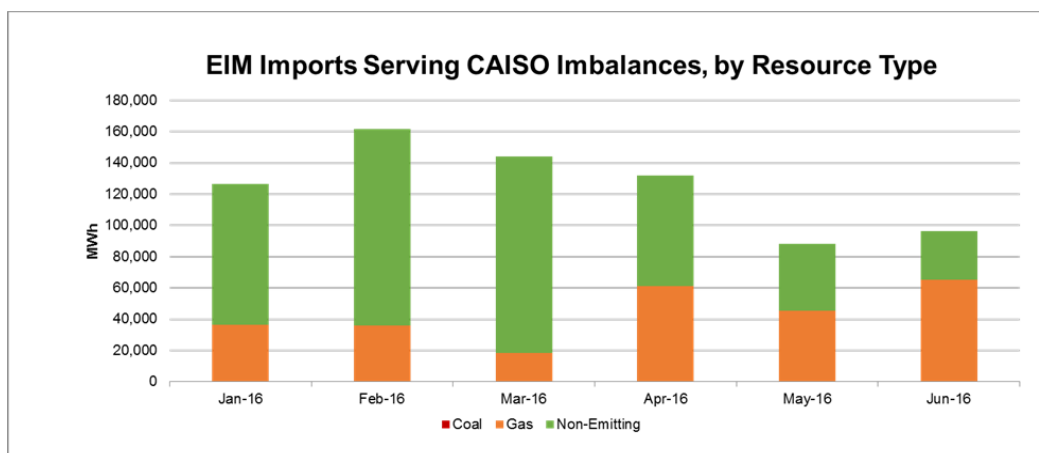
²⁵¹ Export activity is, however, included within CARB’s reporting framework. CARB also provides a limited provision for “Qualified Exports,” which involve imports and exports occurring in the same hour and arranged by the same importer. Powerex believes a Qualified Export is distinct from the issues discussed in this paper and notes that CARB has proposed to remove the Qualified Export provisions from both the Mandatory Reporting Regulation and Cap and Trade Regulation.

²⁵² The bars below the horizontal axis show the California generation that reduces output pursuant to the EIM dispatch.



Source: CAISO EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_Jan-Jun_2016_.pdf at slide 3. Available at: <http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>

In contrast, the chart below shows the EIM's monthly resource-specific allocation of the source of EIM imports serving California load during the same period of 2016 (*i.e.*, how the GHG intensity of those imports will be reported to CARB and, consequently, the amount of GHG emissions allowances that will need to be procured to comply with the Cap-and-Trade Regulation). This chart shows that EIM imports serving load in California have been deemed by the CAISO as mostly from non-emitting resources (green bars), with lower quantities deemed as being from natural gas resources (orange) and none from coal- burning resources.



Source: Plotted from 2016 data in CAISO MonthlyEIM_Transfer_ISO_Imbalances_MWh.xlsx. Available at: <http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>

These comments examine the underlying cause behind this apparent disconnect between the GHG emissions of out-of-state resources actually dispatched in the EIM and the resources in the EIM that are “deemed delivered” to California. Powerex understands that these outcomes occur largely because the out-of-state resources that can be assigned “deemed deliveries” to California by the EIM algorithm are not limited to

the resources that actually increase their production in the EIM. Simply put, the current EIM algorithm does not identify the out-of-state resources that are actually dispatched in order to import energy to serve California load; rather, it selectively “deems” those imports to come from those resources whose CARB compliance costs are lowest. For instance, a non-emitting (e.g., hydro or solar) out-of-state resources might not increase its output in the EIM above its pre-submitted “base schedule” at all, but could still be “deemed” to be the source of a new EIM import serving load in California. Conversely, a high-GHG out-of-state resource could be instructed by the EIM to increase its production, and do so specifically to support additional EIM imports to serve California load, yet the EIM algorithm would not “deem” this resource to be the source of those EIM imports into California. In doing so, the EIM algorithm does not merely minimize CARB compliance costs by reducing emissions, but by minimizing the application of CARB’s GHG Regulations to GHG-emitting resources in the first place. This outcome may, indeed, be “optimal” from a “least cost” perspective for the wholesale electricity sector, but it likely diverges from the intended application of AB 32 and CARB’s policies regarding electricity imports.

It appears that the current EIM algorithm can lead to numerous outcomes that Powerex believes are inconsistent with California’s environmental policy objectives, including understating the GHG emissions of imports into California, causing GHG emissions “leakage,” and undermining CARB’s market-based incentives to encourage imports from low- or zero-emitting out-of-state resources and to discourage such imports from high-emitting resources. Additionally, the treatment of GHG emissions in the EIM algorithm is impacting price formation in the EIM and CAISO real-time markets. In Powerex’s view, the present and continuing environmental and wholesale electricity market impacts require immediate attention and action by CARB, CAISO and stakeholders.

CAISO materials indicate that the current EIM algorithm does not accurately or reliably identify the out-of-state resources dispatched to support imports into California. Consequently, the EIM’s “deemed deliveries” are not a reasonable basis for reporting those imports to CARB using a “specified source” emission rate, as the source specified may often be incorrect. It would therefore appear appropriate to modify CARB’s GHG Regulations to (1) suspend “specified source” reporting for imports into California occurring through the EIM and (2) require that all such imports be reported using the “unspecified source” GHG emission rate, at least until such time as modifications can be made to the EIM algorithm. But such a change should not be considered to be an optimal long term solution: Powerex also believes it is both preferable and possible to revise the EIM algorithm so that it does accurately identify the specific out-of-state resources that are the actual source of EIM imports into California. In these comments, Powerex outlines one proposed approach to achieve this outcome by addressing the current flaws in the EIM algorithm. Powerex acknowledges that other alternative approaches may be available. Once a solution has been developed and CARB is satisfied that CAISO has implemented the necessary improvements to the EIM

algorithm, Powerex believes CARB should once again permit GHG reporting of EIM imports into California on a “specified source” basis.

If and when CAISO expands to become a multi-state regional organized market, it will also be important to ensure that CARB’s GHG Regulations and programs are appropriately applied in this new environment. This indicates a need for the solutions adopted for the EIM to be compatible with the existence of a future regionalized market. The alternatives proposed by Powerex satisfy this objective, ensuring the solution adopted by the EIM does not pose a barrier to regionalization, and continues to be workable in an environment where some entities participate in the EIM but remain outside of a regional market. The EIM is distinct from a regional market, particularly in its need to co-exist with (and not conflict with) substantial trade activity and delivery commitments conducted outside of CAISO’s organized markets but within the EIM geographical footprint. Whereas the existing “contract path” arrangements for bilateral trading and scheduling are augmented by the EIM, which provides additional opportunities for intra-hour transactions, a regional organized market would replace these existing “contract path” arrangements within the expanded footprint in their entirety. The application of CARB’s GHG Regulations to a regional market is therefore likely to differ from application in the EIM. Consequently, the potential for the future expansion of CAISO to a regional organized market should neither delay nor unduly restrict how CARB addresses the immediate concerns over GHG reporting in the EIM.

Ensuring there is a framework for accurately determining GHG emissions in the EIM—and, eventually, in a regional organized market—is critical to achieving California’s environmental objectives in the context of expanding organized electricity markets. The initial experience of the EIM demonstrates that the pursuit of greater regional coordination founded on least-cost optimization solutions requires careful and accurate application of CARB’s GHG Regulations in order to advance California’s underlying environmental goals. Powerex looks forward to continuing to work with CARB, CAISO, and stakeholders toward solutions that deliver the benefits of organized markets across a multi-state footprint, while fully respecting California’s environmental regulations and objectives.

There is an Apparent Disconnect between EIM GHG Reporting and Actual EIM Dispatch of Out-of-State Resources

The EIM jointly optimizes the real-time dispatch of physical generation resources across a footprint including BAAs within California and outside of it. This optimization needs to reflect CARB’s GHG Regulations, which apply to all electric power generation within California as well as to electricity imports that serve load in California. The application of CARB’s GHG Regulations to electricity imports is necessary to prevent out-of-state GHG-emitting resources from displacing in-state resources simply because CARB’s GHG Regulations apply to in-state resources but do not directly apply to out-of-state resources. Preventing such “leakage” is particularly challenging in the EIM, since it means that the GHG costs of resources located outside of California must be

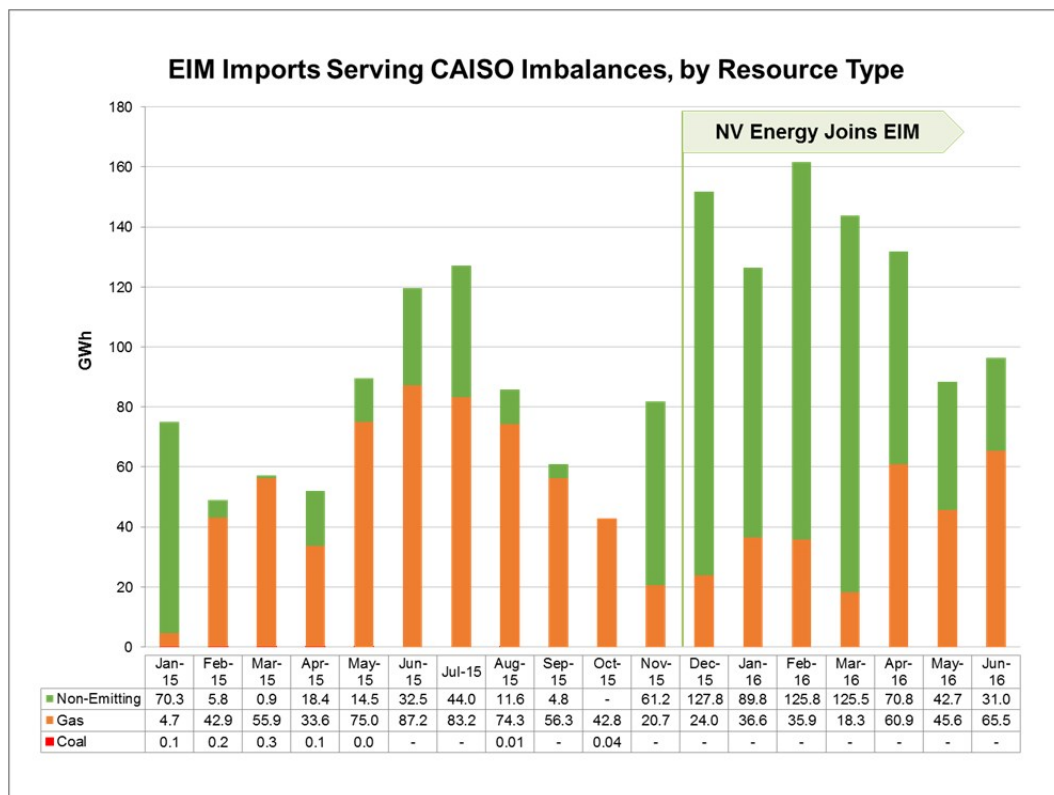
considered when out-of-state resources are dispatched in the EIM to serve load in California, but those costs must be ignored when out-of-state resources are dispatched in the EIM to serve load outside of California.

To implement the California GHG requirements in the EIM, the CAISO modified its Security Constrained Economic Dispatch (“SCED”) algorithms to (1) include a resource-specific GHG bid “adder” to indicate the quantity and price at which the resource is willing to be deemed to be delivered into California; and to (2) assign EIM imports serving load in California to specific EIM participating resources. CAISO explained that the EIM algorithm would incorporate the GHG requirements in a way that results in the lowest total production cost. It was recognized at the time of CAISO’s early EIM tariff filings that the new algorithm would result in the cleanest resources *incrementally* dispatched by the EIM being “deemed” to be imported into California, a design feature termed “efficient resource shuffling” by one prominent industry expert.²⁵³ While this concept was illustrated through simplified examples during the early considerations of the EIM, the full ramifications of this approach can now be assessed in more detail, based on the actual operating experience of the EIM over the past 1.5 years.

The three figures below illustrate the need for a more thorough understanding and review of GHG treatment in the EIM.

The first useful metric for assessing GHG treatment in the EIM is the CAISO’s reporting of EIM transfers to serve CAISO imbalances, which CAISO allocates among (1) coal resources; (2) natural gas generation; or (3) non-emitting resources. This is shown in the chart below, and appears to report that approximately half of these EIM imports are “deemed delivered” from non-emitting resources (green bars), with the remainder from resources that burn natural gas (orange bars). In many months, particularly in 2016, non-emitting resources are the “deemed” source of the majority of EIM imports serving load in California.

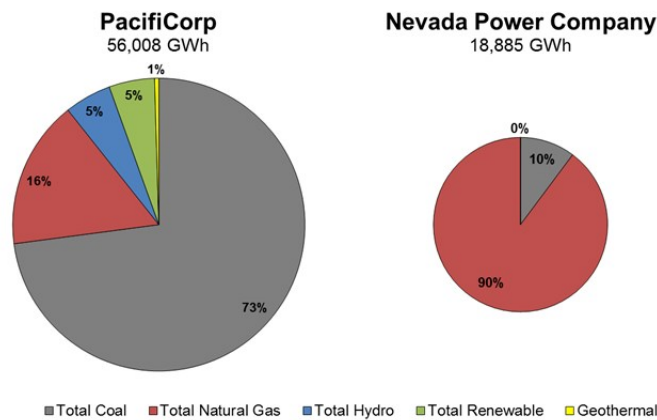
²⁵³ Hogan, W. W. (2013). CAISO Energy Imbalance Market Straw Proposal: Comments (pp. 1–4). Available at http://www.hks.harvard.edu/fs/whogan/Hogan_CAISO_EIM_Notes_062613.pdf



Source: Plotted from *CAISO MonthlyEIM_Transfer_ISO_Imbalances_MWh.xlsx*.
 Available at: <http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>

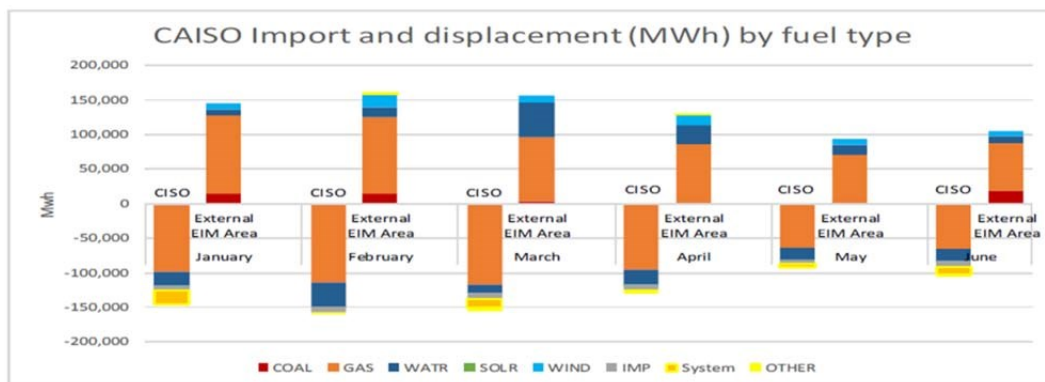
Second, the GHG intensity of EIM imports serving load in California needs to be viewed in the context of the resource mix of the entities that participate in the EIM. This composition is shown below, and consists primarily of coal-fired generation, followed by natural gas resources; with less than 10 percent from nonemitting resources.

2015 Generation by EIM Entity and Resource Type



Note: Resource mix is for each company, and does not include resources in the EIM Entity BAA owned by other entities.
Source: SNL.

Recently, CAISO provided 2016 monthly data on the EIM dispatch of out-of-state resources during the specific intervals that CAISO was importing energy in the EIM. As CAISO explained, “[u]pward bars reflect external supply dispatched in EIM case that would not be dispatched in counter-factual without EIM.”²⁵⁴ The figure below shows that, when electricity is being imported into California in the EIM, the resources increasing their output in the EIM are mostly natural gas resources, with a limited amount of hydro and coal resources increasing output as well.



Source: CAISO *EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_Jan-Jun_2016_.pdf* at slide 3. Available at: <http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>

The above charts present contradictory representations of the GHG emissions associated with California imports in the EIM. On the one hand, these imports are being

²⁵⁴ CAISO *EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_Jan-Jun_2016_.pdf*, at 2.

reported as being substantially—and at times predominantly—from “clean” out-of-state resources. But this does not appear to be consistent with the composition of resources in the EIM Entity BAAs, nor with the types of out-of-state resources that *actually increase output* when California is importing energy in the EIM, which appear to be mostly gas generation, with a lesser amount from coal and non-emitting resources.

The addition of NV Energy’s resource mix and transmission capacity to the EIM in December 2015 further highlights this disconnect. Beginning in December, the portion of EIM imports serving load in California that was reported as being from non-emitting resources increased sharply. This change does not seem consistent with NV Energy’s resource mix—which consists almost entirely of gas or coal generation—nor does it appear to be supported by any increase in the dispatch of non-emitting resources in the EIM.²⁵⁵ Again, there appears to be a substantial misalignment between the resources being “deemed delivered” to California and the actual dispatch of resources in the EIM.

This apparent misalignment indicates that the EIM algorithm does not properly recognize GHG emissions when dispatching out-of-state resources. This should be of substantial concern to CARB because, as further discussed herein, it suggests that the current dispatch of resources in the EIM may be leading to several unintended outcomes:

- Carbon leakage appears to be occurring in the EIM on an ongoing basis, and is likely to grow as the EIM expands.
- Resources with high-GHG emissions are increasing production relative to their base schedules, resulting in additional power being transferred to California, but without the appropriate quantity of carbon allowance obligations being incurred.
- The EIM dispatch decisions and price signals for both high-GHG and low-GHG resources do not appear consistent with the way the GHG program seeks to achieve its environmental objectives.
- Compensation provided in the EIM to both high-GHG and low-GHG resources appears inconsistent with the state’s environmental objectives; the EIM appears to over-compensate external fossil fuel generation that is incrementally dispatched to supply the CAISO grid, and simultaneously appears not to appropriately compensate—or encourage the expanded participation and use of—clean resources.

As further discussed below, Powerex also believes that, absent appropriate steps being taken to correct the current EIM dispatch and GHG allocation algorithm, the above problems will likely worsen as the EIM expands its footprint and includes additional

²⁵⁵ NV Energy’s participation in the EIM also increased the available transfer capability between PacifiCorp East’s Balancing Authority Area and the CAISO BAA. However, additional transfers from PACE also would not explain the increase in non-emitting imports into California, given the limited quantity of non-emitting resources in the PACE BAA.

participating resources. Over time, Powerex believes EIM expansion without correcting these inadvertent flaws can be expected to produce the following problematic results:

- Eventually, it is possible that little if any, GHG carbon allowance obligations will be incurred in the EIM, including in intervals in which increases in production in the EIM are predominantly (or entirely) from GHG-emitting resources. Over time, the EIM footprint may include sufficient nonemitting resources whose output could be selectively “deemed” by the EIM algorithm to support EIM imports into California in every hour, regardless of whether those resources actually increase their production in the EIM.
- The EIM will become a “market of choice” for high-GHG emitting resources located outside of California, because it affords a unique opportunity for such resources to make sales and increase production that directly result in deliveries to California without incurring the appropriate GHG allowance obligations that would otherwise apply to such activity. If the same activity occurred outside the EIM, the resource would face a GHG allowance obligation at either its resourcespecific GHG intensity or at the unspecified GHG intensity.²⁵⁶
- The EIM will become a relatively less attractive market for real-time energy sales from low-GHG emitting or clean resources located outside of California, as the low/zero-GHG attributes of the resource may receive little, if any, compensation in the EIM.

II. Proper Accounting of GHG Emissions Associated with EIM Imports is Critical to Achieving the Objectives of CARB’s Cap-and-Trade Regulation

In AB 32, California set out to track and reduce the state’s GHG emissions, including those associated with its electricity sector. CARB regulates GHG emissions from electricity generation in the state, as well as from electricity imports into California.

For the majority of the first two years of the Cap-and-Trade Regulation, it was relatively straightforward for the CAISO market design to accommodate the regulations surrounding GHG emissions. The CAISO market either procured energy directly from physical resources located within California or it procured energy from importers into the state.

The implementation of the EIM in November 2014 introduced a new challenge. Through the EIM, CAISO determines the economic dispatch of physical generation

²⁵⁶ Arguably, a bilateral trade could be arranged outside of the EIM whereby a high-GHG resource serves the load of an entity that owns non-emitting generation, which in turn is able to then schedule its zero-GHG generation into California. In such a scenario, however, the high-GHG resource would typically receive a discounted price (relative to the price inside California), providing a very important price signal to discourage incremental production from high-GHG resources for import into California. When an analogous transaction is arranged in the EIM, however, this critical price signal is bypassed, and high-GHG resources may be dispatched, and potentially receive compensation, as if there were no CARB program in place at all.

resources located outside of California. Emissions from these resources are not subject to the Cap-and-Trade Regulation directly. However, to the extent these resources result in electricity imports into California, then CARB's rules do apply. The result is that the EIM's dispatch of out-of-state resources requires accounting for GHG emissions—and complying with CARB's GHG Regulations—in certain cases, but not in others.

In recent months, CARB has expressed concerns over how the EIM is performing this function. In examining this issue, the CAISO notes that any concerns regarding the reporting of GHG emissions for imports into California in the EIM “should be considered in the context of the atmospheric effect of the EIM dispatch also when it exports renewable output from California.”²⁵⁷ In support of this position, CAISO recently conducted an analysis showing that the EIM has led to significant GHG reductions during periods of California EIM exports, which greatly outweigh the GHG increases it found during periods of California EIM imports.

Notwithstanding the *overall* environmental benefits of the EIM, Powerex believes it is still necessary to examine the manner in which the EIM accounts for GHG emissions associated with California imports, for several reasons.

First, Powerex understands CARB's concern is not whether the EIM is delivering environmental benefits overall. Indeed, Powerex believes the EIM may very well be providing substantial environmental benefits, relative to an EIM not existing at all. But the issue at hand is whether the EIM appropriately applies CARB's GHG Regulations; the answer to that question does not depend on whether GHG emissions in the EIM footprint increase or decrease as a result of the existence of the EIM.²⁵⁸

Second, the environmental impacts of EIM exports out of California are not credited by CARB for avoided emissions associated with displaced out-of-state resources, nor does the EIM algorithm incorporate any GHG-related information when deciding which out-of-state resources should reduce output to absorb this exported energy. In other words, these environmental benefits would occur anyway, even without CARB's GHG Regulations regarding out-of-state sources of energy. The proper application of CARB's rules regarding electricity imports cannot be evaluated by pointing to emissions reductions from an entirely different activity (*i.e.*, electricity exports) to which CARB's compliance obligation framework does not even apply.

Third, the fact that the EIM, *overall*, may already be providing significant environmental benefits does not imply that it is providing the *optimal* environmental benefits or is operating consistent with the objectives of the CARB program. In fact, CAISO's own analysis concludes that in recent months the environmental benefits of the EIM have

²⁵⁷ CAISO *Regional Integration California Greenhouse Gas Compliance Issue Paper* (August 29, 2016) at 8. Available at <http://www.caiso.com/Documents/IssuePaper-RegionalIntegrationCaliforniaGreenHouseGasCompliance.pdf>.

²⁵⁸ CARB's Cap-and-Trade Regulation ensures that GHG emissions are reflected in the cost of electricity imports; it does *not* require that regional GHG emissions from electricity production be reduced.

arisen entirely from California *exports*; the EIM's California *imports* actually have increased total GHG emissions in the EIM footprint. Proper application of CARB's rules to EIM imports can be expected to increase the EIM's environmental benefits beyond what is already being achieved.

Fourth, there is no reason why GHG emissions associated with EIM imports into California should be "credited" against the GHG emissions reductions associated with EIM exports from California, when a similar "crediting" framework is not available for imports and exports that occur outside of the EIM. For instance, there are exports from California that can be scheduled in the CAISO day-ahead or real-time markets, and these, too, may permit California renewables to avoid being curtailed while permitting out-of-state GHG emissions to be reduced. And yet CARB's GHG Regulations do not provide for such export-driven GHG reductions to reduce the reporting or compliance requirements for electricity imports into California that occur in other periods. No justification has been proposed for treating imports in the EIM any differently.

For the above reasons, Powerex strongly believes that the EIM must be required to accurately and objectively apply CARB's GHG Regulations to all EIM imports into California, notwithstanding the environmental benefits of California exports facilitated by the EIM.

III. GHG Provisions in Initial EIM Design Development Were Appropriately Focused on Incremental Dispatch of Out-of-State Resources

At the time that the EIM framework was being developed in the CAISO stakeholder process, Powerex believes it was widely understood that the EIM would efficiently dispatch and allocate incremental production, and would do so by explicitly including GHG-related costs in its decisions. For instance, if a resource in PacifiCorp's BAA was incrementally dispatched in the EIM to meet real-time load in California, the EIM would include the GHG-related costs of that external resource in its dispatch decision, and this EIM dispatch would result in a "specified source import" into California for purposes of California's carbon program. And since each resource submitting bids into the EIM would specify its unique GHG-related costs, the EIM software would be able to take these costs into account to find the most economical way, including GHG-related costs, of serving California load. This approach represented a potential improvement over how GHG costs are managed for non-EIM imports into California, which are generally deemed as being from an "unspecified source," unless they are delivered directly to California under a contract for the output of a specific resource.

In the course of developing the EIM framework, including the GHG provisions, it was also recognized that there would be situations in which there was ambiguity regarding whether an external resource was used to serve load in California as opposed to serving load outside of California. In examples presented by CAISO during the stakeholder process, multiple generators located outside of California could be incrementally dispatched in the EIM in order to serve incremental loads both within

California and outside of California.²⁵⁹ It was explained that the EIM design in this case would “deem” that the output from the lowest-emitting resources is delivered to California, while the output of higher-emitting resources is “deemed” to be delivered to load outside of California. In other words, the CAISO algorithm would effectively solve these ambiguities in a manner that minimized costs through allocating imports to California to resources in a manner that minimizes the total carbon allowance obligations incurred. CAISO also discussed more complex examples, where the most economic resource to serve California load (*i.e.*, including GHG-related costs) may not be the most economic resource to serve non-California load (*i.e.*, excluding GHG-related costs).

From Powerex’s experience as an active participant in the EIM stakeholder process, all of the stakeholder discussions, proposals, and presentations shared a common feature: *GHG responsibility for imports into California was always allocated to resources that had been incrementally dispatched in the EIM.*²⁶⁰ In those examples, EIM imports serving load in California were always the result of resources outside of California increasing their production in the EIM. Consequently, Powerex believes it was widely understood that it was only the resources that increased their production in the EIM that could be “deemed” to serve California loads in the EIM. As implemented, however, the EIM algorithm can deem a resource to serve California load in excess of that resource’s incremental EIM dispatch.

IV. The EIM Algorithm for Assigning GHG Responsibility for Imports has had Significant Unintended Consequences and Is Inconsistent with California’s GHG Program and Objectives

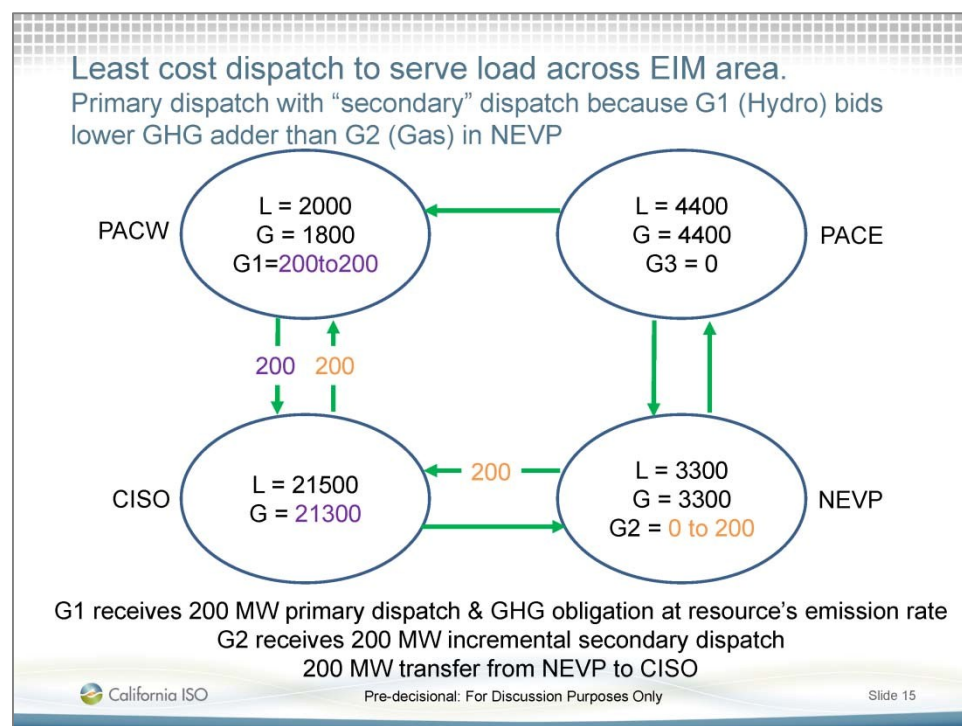
In its simplest form, the EIM algorithm for assigning GHG responsibility is designed in a manner that permits it to “re-arrange” the base schedules of EIM participating resources. Even though a resource outside of California may have a base schedule that clearly and unambiguously commits it to serve load outside of California, it may nevertheless be deemed to also serve load inside of California as a result of the EIM. This appears to be possible even if the level of output of the resource is completely unchanged. In other words, the EIM algorithm goes beyond the “efficient resource shuffling” of the *incremental* production in the EIM—where the lowest-emitting *incremental* output is deemed to serve California load—it may “re-route” *any or all* of the output of a resource.

²⁵⁹ CAISO EIM Draft Final Proposal (September 23, 2013) at 90-95. Available at <http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf>.

²⁶⁰ See, e.g., CAISO EIM Draft Final Proposal at 84 (“Thus, only the imbalance energy portion that is imported into the ISO would be subject to a GHG compliance obligation.” Emphasis added) and CAISO stakeholder meeting presentation at slides 39-40 (“EIM dispatch algorithm will include GHG bid adder for imbalance energy of EIM Participating Resources that transfer to ISO”. Emphasis added). Available at <http://www.caiso.com/Documents/Agenda-Presentation-EnergyImbalanceMarketDraftFinalProposal.pdf>.

The potential for such an outcome to occur was recognized and explained in CAISO's June 24 presentation using the example reproduced below.²⁶¹ In the example, PACW G1 is a hydro resource located in the PACW BAA, and has a 200 MW base schedule to serve load in the PACW BAA. NEVP G2 is a gas-fired generator located in the NEVP BAA; its base schedule is zero. In the EIM dispatch, the output of the NEVP G2 gas-fired resource is increased by 200 MW; there is no net change in the output of the PACW G1 hydro resource, and generation within the CAISO BAA is reduced by 200 MW. The net EIM Transfer is therefore 200 MW from NEVP to CAISO.

The GHG responsibility for the EIM imports serving load in California would appear to be most reasonably assigned to the NEVP G2 gas-fired resource, which is the only resource that increased its output in the EIM. But under the EIM algorithm currently employed, this is not the outcome that occurs in this example. Instead, the GHG responsibility for the EIM imports serving load in California is assigned to the PACW G1 hydro resource, even though its output level precisely matches its base schedule; it has not increased its production in the EIM at all.



The CAISO's example demonstrates that the EIM is currently able to procure additional energy from resources outside of California and import that energy without recognizing and reporting the correct GHG emissions associated with the imported energy. In

²⁶¹ CAISO Energy Imbalance Market GHG Design Discussion, June 24, 2016. Available at http://www.arb.ca.gov/cc/capandtrade/meetings/062016/arb_and_caiso_staff_presentations.pdf.

Powerex's view, this is contrary to CARB's GHG Regulations that seek to prevent carbon "leakage,"²⁶² and is also contrary to the purpose of establishing a

GHG adder and assigning GHG responsibility for imports in the EIM. The EIM algorithm will dispatch the NEVP G2 resource, and import a corresponding amount into California, based solely on NEVP G2's energy bid. The EIM algorithm will ignore the GHG adder for NEVP G2, and will also ignore if G2 indicates it is not willing for its output to be imported to California at all.¹⁵ By ignoring the GHG adder, the EIM algorithm may even dispatch NEVP G2 under circumstances in which it would not be dispatched if its GHG adder was appropriately included. Powerex believes this is not how stakeholders expected the EIM's GHG adder to work. Moreover, in Powerex's view the current EIM algorithm not only distorts the dispatch decision, it also assigns GHG responsibility for the import to the wrong resource. In this case, the California import is "deemed" to come from PACW G1, and not from the NEVP G2 resource that was actually dispatched. This incorrect assignment results in the California import being reported as sourced from a non-emitting resource rather than from an emitting resource. It also results in "deemed deliveries" from PACW, even though the e-Tags will show energy transfers in the EIM being delivered from NEVP to CAISO and rather than from PACW to CAISO.

Appendix A contains a more extensive discussion of the CAISO's example, as well as additional scenarios using different assumptions. Each example explores both the dispatch solution that Powerex understands would result from the current EIM least-cost optimization, as well as the assignment of GHG responsibility based on how that algorithm has been described to date.

The outcomes under CAISO's example, above—as well as under each of the other scenarios explored in Appendix A—appear to Powerex to be inconsistent with the core purpose of California's carbon program, in at least the following ways:

1. Dispatches the wrong resources. If the EIM algorithm correctly recognized that NEVP G2 was the resource actually producing the incremental energy that is being imported into California, it would evaluate the cost of dispatching that resource based on both the energy bid component and its GHG adder. Under CAISO's example, this may make the dispatch of NEVP G2 uneconomic, and instead the EIM would seek to dispatch other, lower cost and/or lower GHG-emitting resources to meet California's needs.

2. Promotes carbon "leakage." The failure to recognize the GHG attributes of resources used to supply imports to California appears to unintentionally undermine CARB's rules to address "leakage," allowing GHG emissions to shift from in-state sources (where they are regulated) to out-of-state sources (where they are not regulated).

²⁶² Under AB 32, "leakage" is defined as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." California Health & Safety Code Section 38505(j). ¹⁵ *Supra* note 13 at slide 16.

3. Disadvantages California resources compared to out-of-state generation. The CARB rules regarding imports are also intended to prevent in-state generation from being unfairly disadvantaged and displaced by energy imported from outside of California. The current EIM algorithm appears to unintentionally weaken those protections.

4. Reduces and/or nullifies incentives for clean electricity imports. The CARB rules regarding imports also seek to encourage imports from low- or zero-GHG resources rather than from higher-GHG resources. Powerex believes this objective is undermined by the current EIM algorithm, which can allow the GHG intensity of external resource production to be ignored and can result in high-GHG emitting out-of-state resources being dispatched instead of lower-GHG emitting out-of-state resources.

5. Improperly assigns GHG responsibility to the wrong resources. In the CAISO example, the PACW G1 hydro resource will be informed that it was deemed to import 200 MW into California, despite having committed and scheduled its 200 MW of output to serve load in the PACW BAA. Despite producing exactly according to its base schedule, PACW G1 will now incur the obligation to report its “deemed” California import to CARB and to surrender the associated quantity of GHG emissions allowances, if any. Critically, this reassigning of energy production associated with PACW G1’s base schedules (without any actual changes in PACW G1’s production level) occurs even though PACW G1 has already explicitly *chosen* to schedule delivery of its base schedule volume to specific loads outside of California, and even though PACW G1 did *not* offer to sell the base-scheduled portion of its energy production in the EIM. Conversely, NEVP G2 may bear *no* GHG responsibility, even if it was the sole resource incrementally dispatched in the EIM to satisfy an imbalance in the CAISO.

6. May lead to double-counting of clean imports into California. The 200 MW of imports assigned to PACW G1 in the CAISO example contradicts the base schedules submitted by PACW G1, in which the output was committed to serve load in PACW. But the EIM would also disregard base schedules in which PACW G1 was committed and e-Tagged prior to the EIM to serve load in California. This could lead to the clean import being claimed twice: first for the scheduled delivery from PACW G1 into California—as confirmed by its e-Tag—and then a second time for the deemed delivery from PACW G1 in the EIM. Through no action of its own, PACW G1 may appear to be the source of 400 MW of clean imports into California even though it only produced 200 MW in that hour.²⁶³

²⁶³ Under the current version of MRR Section 95111(b)(2)(E)(3), while hourly meter data is required to verify the import of energy from a specified source via an e-Tag, “untagged power deliveries, including EIM imports” are excluded. The potential for double counting is enhanced in circumstances where PACW G1 is sold to a third party as a “Specified Contract”. If the third party imports this energy into California, the third party may claim the import as a specified source and have the import verified based on the associated e-Tag and meter data. This import could also be a “base schedule” under the EIM. If G1 is then deemed delivered in the EIM, the generation output supporting the non-EIM import may also be reported by the EIM entity in support of a “deemed” EIM import. Powerex notes that the EIM

7. Favors EIM participation by (and use of) high-GHG resources. The current EIM algorithm creates an opportunity for high-GHG generation resources outside of California to do something they cannot otherwise do, which is to produce energy that results in EIM imports into California while potentially avoiding CARB's GHG Regulations. This may make EIM participation highly attractive for high-GHG resources outside the state, and may unintentionally provide additional financial incentives for their increased use and continued operation.

8. Discourages EIM participation by (and use of) low- or zero-GHG resources. By not properly distinguishing between high- and low- or zero-GHG resources, the EIM may discourage (or at least may not encourage) participation by clean resources. It may also not provide the appropriate level of financial incentives to expand the use of clean resources as intended under the state's GHG program.

9. Understates demand for GHG emissions allowances. By not accurately recognizing the GHG intensity of resources that increase their output in connection with EIM imports serving load in California, the current EIM algorithm understates the GHG emissions allowances that are required to be surrendered. This effectively leaves additional allowances available for other entities to acquire to support additional GHG emissions. Depressing the demand and the price for all California GHG allowances weakens the incentives to achieve the state's emissions reduction targets.

Perhaps of greatest concern to Powerex is that each of these problems can be expected to grow as the EIM footprint expands, regardless of whether each problem is experienced frequently today. For example, there may currently be relatively few day-ahead imports into CAISO that are scheduled and eTagged from clean resources in the PacifiCorp or NV Energy BAAs, and hence there may currently be only limited risk that California may double-count clean energy imports from those resources (*i.e.*, once as base schedules associated with day-ahead imports into California, and a second time through the deemed delivery approach of the EIM). However, the EIM footprint is already set to expand to other BAAs that do have significant quantities of zero- or low-GHG resources, and many of these resources may be used to support deliveries to California in the CAISO's day-ahead market, potentially opening the door for significant growth in inadvertent double-counting.

Moreover, given the potential benefits that the EIM affords participants, it is also plausible that the EIM will continue to expand rapidly and may eventually even become the principal real-time market in the West. Under the current EIM approach, this will likely result in little, if any, GHG carbon allowance obligations being incurred at all in the EIM, including in intervals when increases in production in the EIM are predominantly (or entirely) from GHG-emitting resources. This is because a significantly expanded EIM would likely always include large quantities of base schedules from low- or zero-

exemption in MRR Section 95111(b)(2)(E)(3) is proposed for removal in the *Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, available at <http://www.arb.ca.gov/regact/2016/ghg2016/ghgatta.pdf>.

GHG participating resources, providing an ample base of clean out-of-state resources whose delivery commitments can be “re-arranged” by the EIM algorithm and “deemed” to be the source of EIM imports serving load in California, even if the resources that actually increase production in the EIM are entirely different and have high GHG emissions.²⁶⁴ The EIM algorithm already “deems” approximately 75% of all EIM imports into California to be from zero-GHG resources, despite these resources representing less than 10% of the energy produced in the PacifiCorp and NV Energy BAAs. Continued EIM expansion utilizing the current EIM algorithm can only be expected to increase the occurrence and magnitude of this incorrect tracking of GHG emissions.

In Powerex’s view, these results would represent a significant setback to California’s carbon program. After developing and fostering appropriate price signals to preferentially encourage imports into California from low- and zero-GHG emitting out-of-state resources, the development and expansion of the EIM has substantial potential to increasingly mute these price signals, and to enable imports of energy from high GHG emitting resources largely as if the CARB program did not exist at all.

V. The Proposed Amendments to the GHG Regulations Are Unlikely to Correct the Adverse Outcomes of the Existing Approach

Powerex agrees with CARB that the existing approach for allocating GHG responsibility for EIM imports serving load in California needs to be examined, and potentially revised. Powerex believes the apparent flawed outcomes produced by the EIM algorithm were unforeseen and unintended. While the adverse consequences are numerous, they are ultimately rooted in two key problems:

- The EIM algorithm does not correctly consider GHG emissions in the dispatch of out-of-state resources to serve load inside the state; and
- The EIM algorithm does not correctly allocate GHG allowance obligations to the out-of-state resources that are used to serve load inside the state.

A. The Proposed Amendments Do Not Address the Key Problems

Neither of these two key problems is remedied by Proposed Amendments to the GHG Regulations. Based on Powerex’s preliminary review, only one of the many adverse consequences of the existing EIM algorithm appears to be addressed by the Proposed Amendments to the GHG Regulations. Namely, the Proposed Amendments to the GHG Regulations would increase the total GHG emissions obligations that must be reported—and the allowances that must be purchased and surrendered—to at least

²⁶⁴ More specifically, whenever the EIM includes base schedules from participating clean resources that equal or exceed the EIM transfer capability into California, the current EIM algorithm would automatically create an opportunity for the EIM to increase production from out-of-state fossil fuel generators, directly resulting in increased power deliveries to California, but without incurring any carbon allowance obligation at all.

equal the application of the “unspecified source” GHG rate to EIM imports serving load in California.²⁶⁵

Unfortunately, however, the Proposed Amendments to the GHG Regulations do not appear to require CAISO to make any modifications to its existing approach for selecting which EIM participating resources to dispatch. Consequently, virtually all of the adverse consequences identified above will continue to occur:

- By not correctly recognizing the GHG costs of incremental out-of-state resources, the EIM will continue to dispatch high-GHG out-of-state resources instead of low-GHG out-of-state resources under certain conditions.
- By not correctly recognizing the GHG costs of incremental out-of-state resources, the EIM will continue to displace production from in-state resources with production from out-of-state resources in a manner that results in “leakage” under certain conditions.
- The EIM will continue to become a “market of choice” for high-GHG out-of-state resources, and continue to provide revenue opportunities not otherwise available to such resources.
- The EIM will continue to discourage (or at least not fully encourage) participation by low- or zero GHG out-of-state resources by not properly recognizing or accurately compensating the clean attributes of these resources.
- The EIM will continue to be able to “re-arrange” base schedules and delivery commitments made prior to the EIM, potentially leading to double-counting of out-of-state clean resources.

B. Assigning GHG Responsibility to “EIM Purchasers” is Inequitable

The Proposed Amendments to the GHG Regulations would require an annual calculation of a supplemental compliance obligation based on the annual GHG emissions from out-of-state resources that serve California load through the EIM, but are not otherwise accounted for through the EIM algorithm. This supplemental compliance obligation would be paid for by “EIM purchasers,” which are “entities that purchase from EIM ... to serve load in California.”²⁶⁶ This implies that the obligation will be assigned to California consumers, and not to the high-GHG out-of-state resources dispatched in the EIM. Powerex believes this is both inappropriate and inefficient. First, California load is settled at locational marginal prices (“LMPs”) within California,

²⁶⁵ See proposed new MRR Section 95111(h)(1)(A) in the *Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, available at <http://www.arb.ca.gov/regact/2016/ghg2016/ghgatta.pdf>.

²⁶⁶ Proposed amendment to Section 95802(a) of the Cap-and-Trade Regulation set forth in *Appendix A – Draft Staff Report: Initial Statement of Reasons - Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation*, available at http://www.arb.ca.gov/cc/capandtrade/draft-ct-reg_071216.pdf.

which already include the GHG adder of the marginal generating unit to serve load at the applicable location. Under the Proposed Amendments to the GHG Regulations,

California consumers will also face a second charge for GHG costs, which in many hours will amount to a double recovery of GHG costs from consumers. Second, the proposed approach departs from the CARB framework of assigning GHG reporting and compliance responsibility either to the *resource* or to the *importer* of electricity, and would now assign that responsibility to the entity that receives the import. This would result in two comingled “classes” of CAISO purchases inside California: those that “include” all GHG costs, and those for which the purchaser will still incur an additional GHG-related cost. Notably, this cost will not be known until long after the fact, and purchasers will have little or no ability to avoid incurring it.

Ultimately, the Proposed Amendments to the GHG Regulations would serve only to require the purchase of additional GHG emissions allowances. While this may be considered a limited improvement over the existing approach, Powerex believes that achieving the objectives of the CARB program requires changes to the manner in which the EIM decides to dispatch out-of-state resources to ensure that those decisions correctly consider GHG emissions when energy is being imported into California.

C. Exposing EIM Participants to Accusations of “Resource Shuffling” is Unnecessary and Harmful

In addition, under the Proposed Amendments to the GHG Regulations, EIM participants could be exposed to accusations of violating CARB’s regulations by engaging in “Resource Shuffling,” which could carry serious consequences. In the context of the Cap-and-Trade Regulation, “Resource Shuffling” means, in part, “any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation.”²⁶⁷ Resource Shuffling is prohibited and a violation of the Cap-and-Trade Regulation.²¹ Currently, Resource Shuffling does *not* apply to deliveries “resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time market.”²⁶⁸

The Proposed Amendments to the GHG Regulations include a modification to the above list of activities that do not constitute Resource Shuffling. Specifically, the draft proposes to eliminate safe harbor protections for deliveries resulting from a bid that

²⁶⁷ As per § 95802(336) of *California Cap On Greenhouse Gas Emissions And Market-Based Compliance Mechanisms* ²¹ *Id.* at § 95852(b)(2)

²⁶⁸ *Id.* at § 95852(b)(2)(A)(10).

clears the EIM.²⁶⁹ Powerex strongly opposes this proposal as both harmful to the EIM and ill-suited to addressing CARB's concerns.

As Powerex understands the proposed regulation, EIM participants could potentially be exposed to claims of having engaged in a "plan, scheme or artifice" as a result of the manner that the EIM determines each resource's "deemed deliveries" to California, because the deemed delivery outcome of the EIM algorithm could result in a lower-GHG source being substituted for a higher-GHG source. This potential liability exposure is inappropriate, as the "deemed deliveries" are the result of the EIM algorithm, and not the result of any dispatch or reporting discretion exercised by EIM participants. Moreover, because the "deemed delivery" determinations are entirely out of the EIM participant's control, there is nothing that an EIM participant can do to ensure its EIM transactions are *not* found to constitute Resource Shuffling under CARB's regulations. To protect against this risk, EIM participants would need to elect to not permit *any* of their output to be deemed by the EIM algorithm to serve load in California, or avoid participating in the EIM altogether. Both outcomes would reduce the efficiency and economic benefits of the EIM, and would also restrict the opportunities for the EIM to substitute GHG-emitting production within California for lower- or non-emitting production that may be available outside of California, and thus would not be consistent with the goals of the CARB programs.

The proposed changes to the provisions regarding Resource Shuffling merely expose individual reporting entities to potentially being held liable for the flaws of the EIM algorithm, but do not address the root of the problem, as discussed in more detail elsewhere in these comments. The proposed removal of EIM transactions from the Resource Shuffling safe harbor is unnecessary, inequitable, and is likely to undermine the other economic benefits provided by the EIM. Powerex urges CARB to eliminate the changes to the Resource Shuffling provisions from its proposed amendments.

VI. Potential Frameworks for More Accurately Assigning GHG Responsibility in the EIM

Powerex believes that two potential solutions merit further consideration by CARB, CAISO and stakeholders:

1. Modify the EIM to treat all EIM imports serving load in California as "unspecified source" energy and apply the corresponding GHG-related cost; and
2. Modify the EIM to accurately identify the specific source of EIM imports serving load in California as the EIM resources that are instructed to increase dispatch in the EIM.

A. Option 1: Apply the GHG Emission Rate for Unspecified Source Energy to All EIM Imports Serving Load in California:

²⁶⁹ As per § 95852(b)(2)(A)(10) of *Appendix A – Draft Staff Report: Initial Statement of Reasons - Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation*

Powerex believes that it would be both straightforward and defensible for CARB to require that all EIM imports serving load in California be reported using the “unspecified source” GHG emission rate. This would produce the same outcome as if the EIM did not attempt to attribute California imports to specific resources outside of California. Moreover, it would be consistent with the treatment of imports into California occurring outside of the EIM framework, where only resources with a specified resource contract for their output and an e-Tag demonstrating scheduled delivery to the state are permitted to report a “specified source” GHG emission rate to CARB.

Powerex believes this approach would not require any change to the EIM algorithm. The EIM algorithm would continue to determine which entities are responsible for reporting EIM imports into California to CARB, but the reporting entities would be required to apply the default “unspecified source” emission rate to those imports. Specifically, this approach would modify CARB’s reporting rules such that:

- The EIM determination of energy “deemed delivered” continues to establish which entity has the reporting obligation to CARB (*i.e.*, the Scheduling Coordinator for the participating resource deemed to be delivered to California); but
- Such deemed deliveries must be reported using the GHG emission rate for “unspecified source” energy, rather than the GHG emission rate for the specific resource that is “deemed” to deliver to California by the EIM algorithm.

It is entirely appropriate for CARB to amend its regulations to require the use of the “unspecified source” emissions rate when it cannot be confident that an import is genuinely served by the specific out-of-state resource that has been identified; indeed, “unspecified source” is the typical “default” rate under existing CARB regulations. As discussed above, CARB cannot be confident that the current EIM algorithm accurately serves the purpose of identifying a specific out-of-state resource that serves load in California. Thus, the use of “specified source” emission rates is not warranted for reporting EIM imports into California at the present time.

This approach appears to offer several improvements over the existing EIM approach:

- It would make the EIM no more favorable than other markets for importing high-GHG energy into California, and thus would prevent the EIM from becoming a “market of choice” that supports, rather than discourages, production from high-GHG resources outside of California to serve load within the state.
- Reporting all EIM imports serving load in California as “unspecified source” energy would significantly reduce the adverse outcomes associated with the current EIM algorithm’s selection

- of resources that are “deemed delivered” to California.²⁷⁰ This would also ensure that the EIM algorithm can no longer lead to double-counting of imports from low-GHG resources or other inconsistent treatment of scheduled deliveries outside of the EIM.
- The purpose of the “unspecified source” emission rate is to reflect the GHG emission intensity of marginal generation outside of California. Based on the recent reports from the CAISO on EIM activity, this appears broadly consistent with the type of resource associated with the majority of energy dispatched in the EIM during periods of EIM imports into California (*i.e.*, natural gas resources). It also appears significantly more accurate than the existing EIM algorithm, which systematically and significantly understates the emissions associated with those imports.
- By applying a uniform GHG adder based on the emission rate for unspecified imports to all EIM imports serving load in California, the EIM will no longer systematically put in-state generation at an economic disadvantage to out-of-state resources. This should reduce the GHG emissions “leakage” that currently can occur.²⁷¹
- It is simple to implement, requiring minor modifications of the Mandatory Reporting Regulation, and is consistent with the existing Cap-and-Trade Regulation. The desirable changes to the EIM would be the result of participants rationally submitting GHG adders that reflect the “unspecified source” treatment of EIM imports serving load in California, rather than requiring direct changes to the EIM algorithm.
- This approach does not require changes to the EIM design, hence it appears subject only to the CARB process for modifying its regulations.

In Powerex’s view, Option 1 represents a significant improvement over the Proposed Amendments to the GHG Regulations, since it is not merely an after-the-fact allocation of costs, but rather an explicit recognition of those costs at the time that the EIM dispatch decisions are made. This is critically important, as it goes beyond simply

²⁷⁰ EIM participating resources would rationally submit GHG adders reflecting the common unspecified emission rate, which would be similar or identical across all resources. Thus, differences in the GHG adder would no longer affect the dispatch of out-of-state participating resources in the EIM. Note that all resources with output that is “deemed delivered” would continue to receive the GHG shadow price, and hence would receive compensation sufficient to cover the CARB compliance cost for these unspecified source imports.

²⁷¹ This approach should not be viewed as unjustly detrimental to low-GHG out-of-state resources. The EIM is an imbalance energy market only, used for settling deviations from base schedules. Participating resources continue to have the opportunity to realize the value of their zero- or low-GHG resources by entering into specified-source contracts for delivery to California prior to the EIM. It is only deviations from these scheduled deliveries that are settled through the EIM, and that would be subject to the proposed “unspecified source” reporting requirement.

requiring additional GHG allowances to be purchased and surrendered, and actually changes the EIM's use of out-of-state resources to meet California load.

Powerex supports implementing Option 1, on a temporary basis, as the first step to improving how GHG emissions are treated in the EIM. It is a workable and reasonable alternative that can be implemented quickly and can remain in place until appropriate improvements to the current EIM algorithm are made.

B. Option 2: Modify the EIM Algorithm to Accurately Identify the Incremental Generation Imported in California

Concurrent with the implementation of CARB's amendments to its regulations to implement Option 1, above, Powerex believes that CARB, CAISO and stakeholders should simultaneously pursue a second— and, in Powerex's view, preferable— approach. Under this Option 2, the EIM would continue to associate imports into California with the dispatch of specific out-of-state resources, but would do so in a much more accurate manner. Powerex describes Option 2, below, and also suggests a potential enhancement.

1. Limit “deemed deliveries” to resource output that is increased in the EIM

Under this approach, the EIM algorithm would continue to work precisely as it does today, except that imports into California could only be recognized as being sourced from incremental production in the EIM. In other words, the EIM algorithm would treat base schedules as being unavailable to be deemed to support additional imports into California in the EIM, since that output has already been scheduled outside of the EIM. Other key GHG-related aspects of the EIM algorithm would continue to operate as they do today:

- The EIM dispatch would continue to optimally procure energy for import to serve load in California from those out-of-state resources with the lowest combined offer price for energy and GHG;
- The EIM algorithm would continue to compensate all resources that are “deemed delivered” to
- California loads based on CAISO's calculated “GHG shadow price;” and
- EIM imports serving load in California would continue to be reported to CARB using the “specified source” GHG emission rate for the participating resource(s) that are “deemed delivered” by the EIM algorithm.

In this manner, the EIM would consider the different GHG costs of out-of-state resources in its dispatch decisions; going beyond merely avoiding “leakage” (between in-state and out-of-state resources) to correctly evaluate the different GHG costs of the various participating resources located outside of the state. Unlike the existing EIM algorithm, however, a resource that simply generates according to its base schedule

could not be “deemed” to serve load in California. Similarly, a resource that enters the EIM with a 100 MW base schedule and is dispatched in the EIM to produce a total of 120 MW could only be “deemed” to import at most 20 MW into California.²⁷² Limiting the EIM’s assignment of “deemed deliveries” only to the incremental dispatch of participating resources located outside of the state would more accurately associate imports into California with the out-of-state resources that the EIM instructs to increase output. It would also restore the proper functioning of the GHG adder in the EIM, which can currently be ignored by deeming the California import to come from a different resource, even if that resource did not increase its production in the EIM at all.

Since this second proposed approach could never result in a participating resource being “deemed to deliver” energy beyond the volume of its incremental EIM dispatch, it will fully respect the delivery commitments arranged in base schedules prior to the EIM. This will avoid potential problems with double counting when the resource’s output has already committed to serve load in California or elsewhere outside the EIM.

In short, under this second proposed approach, the EIM allocation of GHG would be consistent with the approach initially described by CAISO in 2013, and generally understood by stakeholders. The EIM would be able to distinguish between out-of-state resources with different GHG emission rates—which could not occur under Option 1.

2. Potential Enhancement: Permit Excess Base Schedules to be Imported to California

As proposed above, Option 2 would strictly prevent the ability for resource output that is based scheduled ahead of the EIM to then be “deemed delivered” to California in the EIM. However, Powerex recognizes that there is a special and narrow case which may arise in which it is arguably appropriate for resource output included in base schedules to be made available to be “deemed delivered” to California in the EIM. This might occur if forecast load in the EIM Entity is below the base-scheduled load, in which case a portion of the resource base schedules would no longer be needed to serve load outside California. Option 2 could arguably be viewed as requiring that positive imbalances in the EIM BAAs outside of California be self-managed entirely outside of California, even though the EIM was intended to provide joint balancing across the combined multi-state footprint.

If such circumstances are expected to be frequent, Option 2 could be modified to address these conditions. The enhancement would permit the EIM algorithm to correctly identify the out-of-state resources included in base schedules whose output would otherwise be reduced to balance a reduction in out-of-state load. For instance, if load in an EIM Entity BAA is 100 MW less than base schedule, the EIM algorithm could first identify the participating resources (outside of California) whose output would be reduced by 100 MW to absorb the excess energy. The production cost savings from reducing the output from these resources could then be compared to the production

²⁷² This is a maximum number, since EIM participating resources may still elect for their output to not be eligible for delivery to California.

cost savings of importing up to 100 MW into California instead, and the EIM algorithm would choose between these two possible outcomes. If an import into California is the most valuable use of the 100 MW of surplus resource base schedules outside of California, this import can credibly be deemed to be sourced from the resources that otherwise would have reduced their output. In other words, the EIM algorithm would be modified to identify the out-of-state EIM participating resource that would have been backed down but for the EIM import to serve California load, and allow the surplus portion of the base schedule associated with that reduction in output to be imported to California.²⁷³

Powerex notes that the circumstances addressed by this enhancement are examples of the special circumstances that may arise in the EIM. Any proposed revisions to the EIM algorithm should be tested under a range of possible scenarios to examine its performance regarding dispatch of participating resources and assignment of “deemed deliveries” to California. Powerex is optimistic, however, that the current algorithm can be effectively modified to properly incorporate CARB’s regulations and notes that there may be additional options for doing so. Powerex believes a series of technical workshops including CARB, CAISO, and stakeholders may be an effective way to consider, assess, and develop an improved EIM algorithm.

C. Summary of Potential Solutions

The current concerns regarding GHG accounting in the EIM arise from two key design considerations in the EIM algorithm:

- How much of the production of an out-of-state resource is eligible to be “deemed” as an EIM import to serve load in California? Is it only the *additional* production dispatched in the EIM, or does it include the production that was already scheduled in advance of the EIM (*i.e.*, base schedules)?
- On what basis does the EIM algorithm allocate EIM imports serving California load to specific out-of-state resources? Are they allocated based on minimizing carbon allowance obligations, or are they allocated to the resources that actually increase production to support EIM imports serving load in California?

²⁷³ Similarly, Option 2 could be refined to allocate GHG allowance obligations to out-of-state resources that increase their output above the level that would have occurred in the EIM absent EIM Transfers into California. Powerex believes that incorporating an algorithm that calculates the optimal EIM dispatch without EIM imports into California—and uses that as a baseline for identifying the specific out-of-state resources that support the imports that occur in the binding EIM dispatch—could lead to the most efficient dispatch while fully adhering to CARB’s GHG Regulations. While it is not clear to Powerex whether it would be feasible for CAISO to determine the optimized dispatch in the EIM absent EIM imports to California, Powerex supports exploring the feasibility of such an approach. Powerex further notes that, to protect against “double-counting,” the CAISO may need to develop safeguards to ensure that any out-of-state resources that are “deemed delivered” to California were not also scheduled for delivery to California in the base schedules.

Under the current EIM algorithm, the entire output of participating resources—including the base schedules—is eligible to be allocated a “deemed delivery” to California, limited only by the GHG bid quantity. This provides a larger quantity of eligible “deemed sources” than if such deliveries were limited only to the incremental output of each resource in the EIM, over and above the level in the base schedules. The current EIM algorithm then seeks to allocate EIM imports among these eligible “deemed” sources in the manner that minimizes the cost of the reporting obligation. This allocation has nothing to do with the physical flow of energy, nor on what the GHG emissions would have been if imports into California did not occur in the EIM. The current EIM algorithm simply identifies the combination of out-of-state resources that lead to the lowest electricity sector costs (including GHG related costs), thereby minimizing the effect of California’s Cap-and-Trade Regulation.

As discussed in Section III, the allocation of EIM imports into California was discussed with stakeholders and approved by FERC in the CAISO’s initial design. However, the potential for “deemed deliveries” to apply to base scheduled output, and not just to the additional output dispatched in the EIM, was not apparent at that time. The EIM algorithm’s now-apparent ability to “re-route” base schedules in order to reduce the reported GHG emissions for EIM imports is at the heart of the multiple adverse consequences discussed above.

Powerex believes that an appropriate EIM algorithm must not be designed in a manner that permits rearranging base schedules when determining which resources are “deemed delivered” in the EIM to California. The options outlined by Powerex achieve this objective, either by recognizing that the “deemed delivered” resources do not actually represent the GHG emissions of EIM imports into California (Option 1) or by improving the EIM algorithm to correctly identify the marginal out-of-state resources actually dispatched to support EIM imports into California (Option 2).

Both of the proposals described above would ensure that the EIM takes into account the GHG emissions associated with imports into California in EIM dispatch decisions. This is critical to addressing the current flaws that promote leakage, encourage participation of high-GHG resources, and may discourage participation of low-GHG resources. Moreover, both of these proposals would prevent the EIM from inappropriately re-arranging the delivery commitments of base scheduled supply, and would prevent double-counting of the output of clean resources outside of California. This is a key feature to ensuring that GHG reporting in the EIM does not contradict GHG reporting for transactions arranged outside of the EIM, including in a potential future regional organized market.

While these above improvements could be achieved under either of the two proposed solutions, additional benefits are available under Option 2 that are not available under Option 1. Specifically, Option 2 would fulfill the intended ability for the EIM to accurately and reliably distinguish between different out-of-state resources with different GHG-

related costs. Under Option 2, EIM imports serving load in California would be assigned to specific out-of-state resources *incrementally* dispatched in the EIM.

Powerex believes that the Proposed Amendments to the GHG Regulations—which require an annual after-the-fact calculation of residual GHG emissions, and assign this residual to “EIM Purchasers”, would only address one of the adverse consequences of the current EIM algorithm. Namely, the Proposed Amendments to the GHG Regulations would require additional GHG allowances to be procured to a level at least equal to the “unspecified rate” for all EIM imports serving load in California. Moreover, the proposed regulations would create additional adverse consequences, including the creation of new after-the-fact compliance risks related to resource shuffling.

The table below summarizes Powerex’s evaluation of each of the proposed alternatives, as well as of the *status quo* approach, with respect to the impacts on CARB’s programs and on economic dispatch of the EIM.

Problem	Status Quo	CARB Preliminary Draft Proposal	Option 1— EIM Imports reported at Unspecified Source emission rate	Option 2— EIM Imports assigned to incremental out-of-state production	Option 2 (Enhanced) —Option 2, but EIM Imports may be assigned to out-of-state resources that would reduce output to balance excess base schedules
Dispatches the wrong resource?	YES	YES	Improved	NO	NO
Promotes “leakage”?	YES	YES	NO	NO	NO
Disadvantages California resources vs. out-of-state resources?	YES	YES	NO	NO	NO
Reduces incentives for clean energy imports?	YES	YES	Improved	NO	NO
Assigns GHG	YES	YES	Assignment is at the	NO	NO

responsibility to the wrong resource?			unspecified rate		
Potential for Doublecounting of clean imports to California?	YES	YES	NO	NO	NO
Favors EIM participation by high-GHG resources?	YES	YES	NO	NO	NO
Discourages EIM participation by low- or zero-GHG resources?	YES	YES	Improved	NO	NO
Depresses demand for GHG allowances?	YES	NO	NO	NO	NO
Prevents excess base scheduled resources from being imported?	NO	NO	NO	YES	NO

VII. Conclusions and Next Steps

Powerex shares CARB's concerns that the current EIM algorithm does not accurately and reliably identify the GHG emissions associated with imports into California. The approach has resulted in imports being reported to CARB with emissions that are not consistent with the additional production of out-of-state EIM participating resources. Consequently, the quantity of GHG emissions allowances that have been purchased and surrendered in connection with these EIM imports has been depressed, permitting these allowances to be acquired to support additional GHG emissions by other entities or in other sectors. Moreover, the current EIM algorithm is not providing the intended incentives to promote the use of low- or non-emitting resources for energy imports into California. Instead, the current EIM algorithm unintentionally provides incentives for the participation by and dispatch of higher-emitting out-of-state resources, and can lead to the "leakage" of GHG emissions. It also results in inaccurate GHG emissions data being reported to CARB. These inaccuracies have the potential to undermine the integrity of the Cap-and-Trade Regulation, which relies on accurate emissions data to achieve the emissions reduction target mandated by AB 32. All of these consequences are contrary to California's environmental policy objectives and CARB's programs, which seek to reduce the GHG emissions associated with its electricity sector.

Many of the existing concerns can be addressed through CARB's actions alone. However, as outlined above, Powerex believes that the Proposed Amendments to the GHG Regulations would not resolve CARB's concerns, and may introduce new

problems. Specifically, Powerex recommends that CARB strike the changes included within the Proposed Amendments to the GHG Regulations related to a supplemental compliance obligation for GHG emissions from EIM imports into California...

Powerex recommends that CARB modify its regulations to require that, under the current circumstances, EIM imports into California must be reported using the “unspecified source” emission rate. Such treatment would be fully consistent with a conclusion that the current EIM algorithm does not accurately identify the specific out-of-state resources whose output supports the EIM imports serving load in California. This change should be straightforward to implement, as it would not require any modification of the EIM algorithm, is consistent with existing CARB approaches, and would not appear to require amending the CAISO’s tariff. CARB could pursue this change to its regulations immediately, but it should also leave open the possibility that specified-source reporting could once again be supported if and when the EIM algorithm is modified to provide more accurate identification of the out-of-state sources for EIM imports into California. Powerex would support this change in the regulations as the first step to improving how GHG emissions are treated in the EIM.

In addition to these modifications to the GHG Regulations, Powerex would also support continued work among CARB, CAISO, and stakeholders to develop an improved EIM algorithm. The efficiency and environmental benefits of the EIM can and should be further increased by pursuing changes to the EIM algorithm to accurately identify the out-of-state resources that actually support EIM imports serving load in California. Powerex has outlined one such approach, under Option 2, and is committed to continued efforts to develop an improved EIM algorithm. CARB’s involvement in these discussions is critical, however, to ensure that any enhanced EIM algorithm produces results consistent with CARB’s GHG Regulations and policy objectives.

Ensuring that the EIM properly supports and applies CARB’s GHG Regulations and objectives is especially important given that similar issues are likely to be encountered as the CAISO explores expanding to a multi-state regional market. The solution adopted for the EIM must be compatible with the approach to GHG reporting under a regional market. Ensuring consistency now will help avoid the need for another re-design of the EIM algorithm once a regional market is implemented, and will also provide an appropriate GHG framework for entities that participate in the EIM but remain outside of a regional organized market.

Powerex notes, however, that the specific manner for applying CARB’s GHG Regulations in a regional organized market need not be the *same* as the manner for applying them in the EIM. Among other reasons, the EIM applies to a relatively small portion of resource production, serving to *augment* the bilateral transactions with a platform for intra-hour transactions. The EIM must therefore co-exist with a large quantity of transactions and delivery commitments arranged under the contract-path paradigm inside the EIM geographical footprint. The EIM must incorporate GHG emissions in a way that recognizes that not all resource production is due to dispatch in

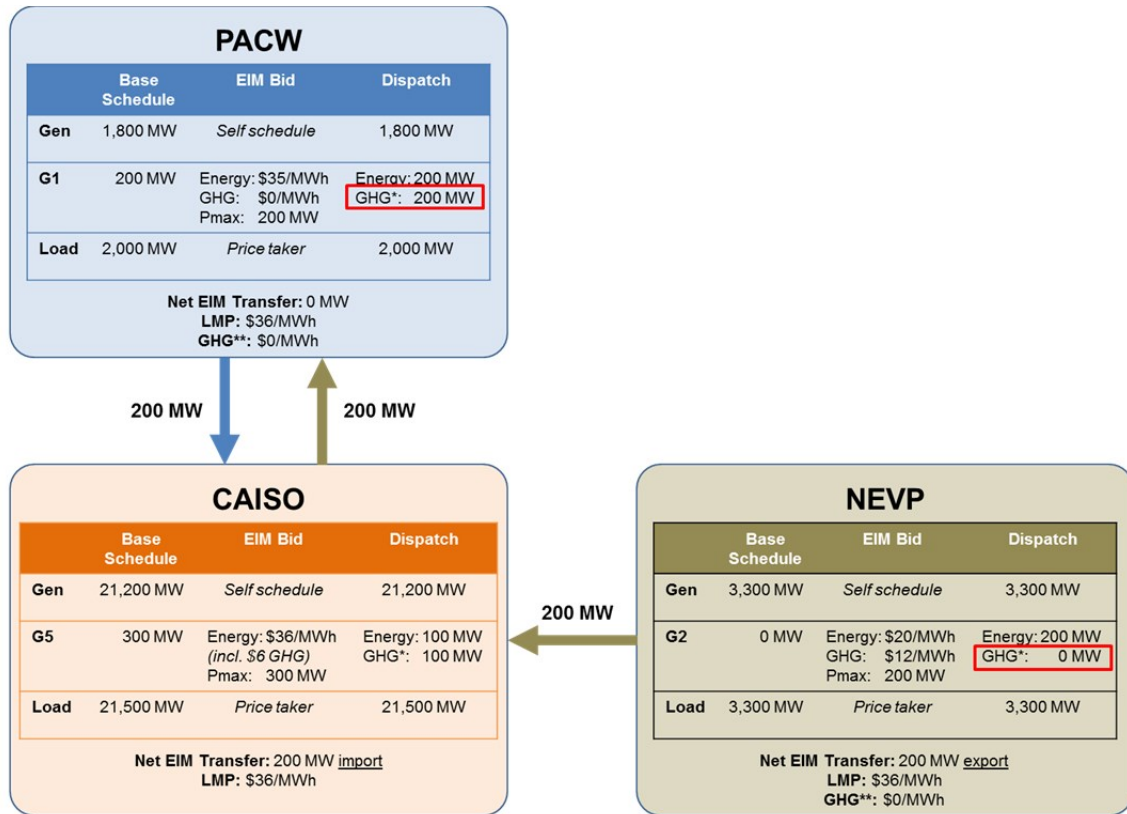
the EIM, and that does not conflict with these non-EIM commitments. A regional organized market, in contrast, would entirely *replace* the existing transaction framework within its footprint. All of a resource's commitment and dispatch will be the result of the regional market optimization, and the market operator will have complete visibility over how the resource is used and how its output flows across the grid. For the above reasons, Powerex believes that improvements in how the EIM treats GHG emissions of out-of-state resources is a distinct and separate issue than how such emissions will be handled in a future regional market.

Appendix A: EIM Dispatch and GHG Allocation

This appendix provides several hypothetical numerical examples of how Powerex understands the EIM algorithm will dispatch both in-state and out-of-state resources. These scenarios are intended to explore how the EIM algorithm's approach to "deeming" the out-of-state resources that are the source of an EIM import serving load in California can distort dispatch decisions, can potentially undermine the intended incentives to encourage participation by low-GHG resources, and result in numerous other adverse outcomes. The EIM algorithm is complex, and documentation of its operation is limited. Powerex therefore hopes that CAISO will identify any aspect of the following scenarios that may benefit from correction or clarification.

Scenario 1: CAISO example with "primary" and "secondary" dispatch

This scenario is consistent with the CAISO example discussed in the main text. Specifically, this scenario consists of each BAA that participates in the EIM submitting base schedules that consist of equal quantities of load and of scheduled generation. In other words, the base schedules imply no net transfers between the BAAs participating in the EIM. For simplicity, PACE is not shown since it does not affect the scenario being discussed, though the same concepts apply to its participation. Additionally, the load forecast in the base schedules is assumed to be perfectly accurate, and be equal to the load forecast used to run the EIM.



* Refers to the quantity of the resource's output that is "deemed delivered" to California, and is subject to CARB reporting and compliance requirements, at the resource's GHG emission rate.
** Refers to the EIM GHG shadow price.

CAISO's example identifies two displacement transactions that occur simultaneously.

The CAISO identifies a "secondary dispatch" in which 200 MW of PACW G1, which has an energy cost of \$35/MWh and a GHG adder of \$0/MWh, is economically displaced by EIM Transfers from NEVP G2, which has an energy cost of \$20/MWh and a GHG adder of \$12/MWh. The GHG adder for NEVP G2 is ignored because, in the CAISO example, NEVP G2 is "deemed" to serve load in PACW—where CARB's GHG program does not apply. This "secondary dispatch" is shown as the green arrows in the diagram above.

Simultaneously, the CAISO identifies a "primary dispatch" in which the same 200 MW of PACW G1 generation displaced by NEVP G2 is available to displace 200 MW of CAISO base schedule generation that costs \$36/MWh (including a \$6/MWh GHG adder) by an EIM Transfer from PACW. This "primary dispatch" leads CAISO G5 to reduce its production from 300 MW to 100 MW and is shown as the blue arrow in the diagram above.

The net result is that CAISO G5 produces 200 MW *less* than its base schedule (reducing from 300 MW to 100 MW), and NEVP G2 produces 200 MW *more* than its base schedule. Nevertheless, the EIM algorithm will "deem" that the EIM import serving load in California was not sourced from NEVP G2, but from PACW G1, despite the fact that the output of PACW G1 *exactly* matches its base schedule quantity of 200 MW.

Importantly, this scenario represents a very particular circumstance in which there are two distinct opportunities for economic displacement to occur. First, the CAISO base schedule includes generation from CAISO G5, despite lower cost supply being available from outside California (e.g., from PACW G1). Second, the PACW base schedule includes generation from PACW G1, despite lower cost supply being available from NEVP G2. The EIM simultaneously resolves both of these “inefficiencies” in the base schedules, potentially introducing some ambiguity regarding whether:

A. NEVP G2 was dispatched to serve load in PACW (displacing PACW G1), and simultaneously PACW G1 was dispatched to serve load in California (displacing CAISO G5); or

B. NEVP G2 was dispatched to serve load in CAISO, and PACW G1 simply served PACW load consistent with its base schedule.

In other words, the characterization of this scenario as involving a distinct and economic “primary dispatch” and “secondary dispatch” appears to make its plausible—or at least not patently wrong—that the EIM algorithm would “deem” the EIM import serving load in California to be a zero-GHG import sourced from PACW G1.

Powerex does not believe that the discussion of the “primary” and “secondary” dispatches in this scenario can be applied more generally to characterize how the EIM algorithm assigns GHG responsibility, however. First, the notion of a rational, simultaneous “primary” and “secondary” dispatch is only possible when the prices offered by resources inside and outside of California are arranged in a very narrow and specific manner:

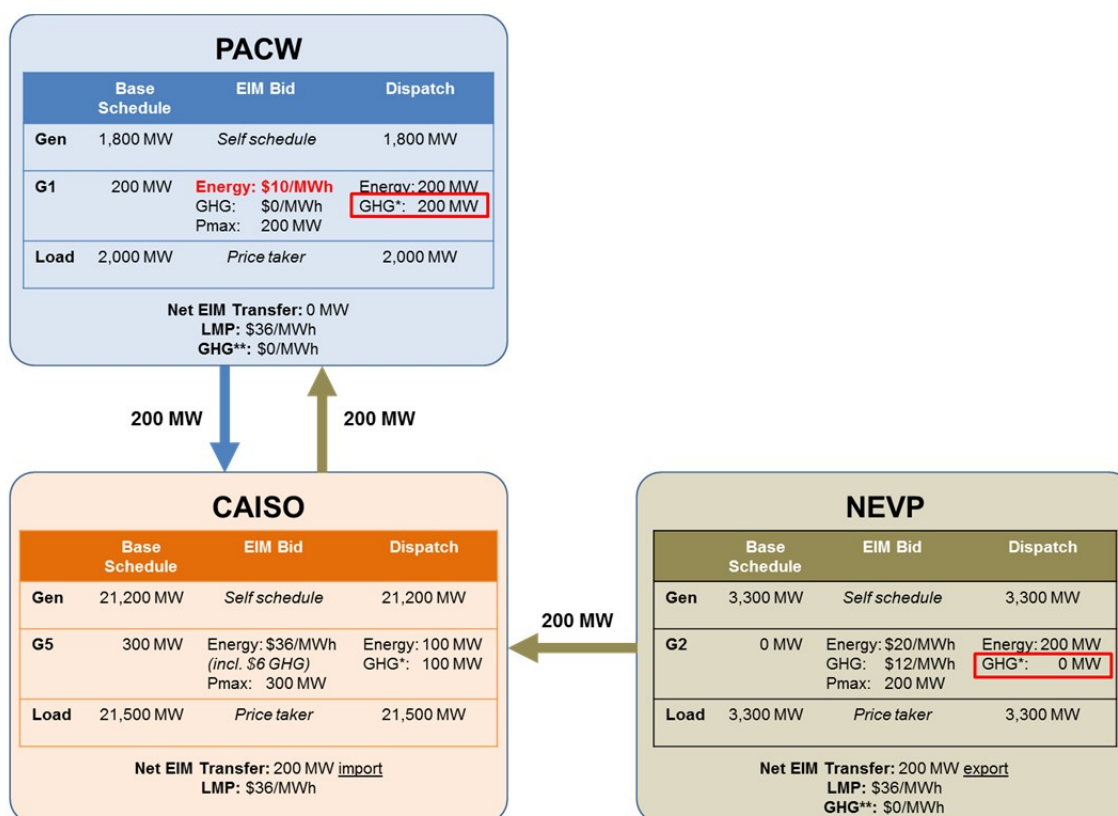
1. CAISO G5 must be more expensive than PACW G1, *including* GHG costs for both resources (creating the “primary dispatch” opportunity); and
2. PACW G1 must be more expensive than NEVP G2, *excluding* GHG costs for both resources (creating the “secondary dispatch” opportunity).

Powerex believes that such a precise alignment of resource offers is likely to be relatively uncommon in the EIM. In particular, many zero-GHG resources like wind, solar, or run-of-river hydro will tend to have relatively low variable costs, making criterion 2, above, less plausible.

The following scenario shows a much less ambiguous and problematic outcome, in which the EIM algorithm will “deem” the EIM import serving load in California to be a zero-GHG import from PACW G1 even when simultaneous economically driven “primary” and “secondary” dispatch clearly does not occur.

Scenario 2: General example without economically driven “primary” and “secondary” dispatch

This scenario is identical to Scenario 1, except that the energy bid price of PACW G1 is \$10/MWh (instead of \$35/MWh). This eliminates the economic opportunity for the “secondary dispatch” from Scenario 1, since it is no longer economic to displace the output of PACW G1 (\$10/MWh) with output from NEVP G2 (\$20/MWh, excluding GHG) on a stand-alone basis. The only economic displacement opportunity available in the EIM is to replace the scheduled output of CAISO G5 (\$36/MWh, including GHG) with incremental output from NEVP G2 (\$20/MWh energy plus \$12/MWh GHG adder). The anticipated solution, based on Powerex’s understanding of how the EIM algorithm incorporates GHG costs into its least-cost dispatch, is illustrated below.²⁷⁴



* Refers to the quantity of the resource’s output that is “deemed delivered” to California, and is subject to CARB reporting and compliance requirements, at the resource’s GHG emission rate.
** Refers to the EIM GHG shadow price.

Notably, it appears that the current EIM algorithm would still “deem” that the EIM import serving load in California was sourced from PACW G1, as opposed to from NEVP G2.

²⁷⁴ The least cost nature of the illustrated solution can be compared to the bid-in cost of alternative solutions. In the absence of any incremental output from NEVP G2, CAISO G5 would be dispatched to 300 MW, resulting in a higher bid-in production cost by $200 \text{ MW} * (\$36 - \$20) = \$3,200$. Alternatively, if NEVP G2 displaces CAISO G5, but is deemed to be the source of imports to California (and hence its GHG adder applies), then total bid-in production costs would increase by $200 \text{ MW} * (\$12/\text{MWh}) = \$2,400$ over the solution shown in the diagram. Powerex requests that CAISO confirm whether the current EIM algorithm would produce the solution shown in the graphic, and assign GHG responsibility to PACW G1.

It is undeniable, however, that the imports into California are due to the incremental output from NEVP G2, and not from PACW G1 (where there is no incremental output at all). For instance, if NEVP G2 did not offer any energy into the EIM, then CAISO G5 would generate according to its base schedule and there would be no imports into California. By the same token, if there were no imports into California, there would be no incremental dispatch of NEVP G2. Reduced output from CAISO G5 is dependent on increased output from NEVP

G2, and vice versa, neither of which have any impact on the output of PACW G1. And yet, the current EIM algorithm would “deem” that PACW G1 is the source for the EIM import serving load in California.²⁷⁵

There are several adverse consequences in this scenario of the EIM not recognizing that the import serving load in California is, in fact, provided by NEVP G2:

- The GHG emissions associated with serving California load are severely understated. This undermines the accuracy of California’s GHG tracking program and reduces demand for California GHG emissions allowances.
- NEVP G2 avoids the cost it would otherwise incur to import energy into California.²⁷⁶ Instead, NEVP G2 receives the full \$36/MWh market clearing price for energy in the EIM. This outcome undermines the price signals intended to be created by California’s carbon program to disfavor generation by and imports from high-GHG resources. It also provides greater compensation to high-GHG resources than is otherwise available through transactions outside of the EIM, and thus actually *encourages* EIM participation by, and production from, high-GHG resources.
- PACW G1 incurs a GHG reporting obligation despite not increasing its output or making an energy sale in the EIM. PACW G1 may have fully scheduled its generation to another BAA, but the very act of being an EIM participating resource appears to create the potential to incur a CARB reporting obligation for its full base schedule.
- PACW G1 is “deemed” to deliver energy to California, *in addition* to the delivery arrangements and e-Tags submitted in support of its base schedules. The same 200 MW of PACW G1 may be shown as delivered to the PACW BAA (according

²⁷⁵ The inclusion in the EIM of the PACW G1 base schedules is critical to the EIM algorithm’s ability to ignore the GHG cost of NEVP G2. For instance, if the PACW G1 base schedule (and Pmax) were 100 MW (rather than 200 MW), then NEVP G2 would only be dispatched for 100 MW in this example; beyond that quantity, any further dispatch of NEVP G2 would have to be recognized as serving California loads, which would be uneconomic. As discussed in Section IV, expansion of the EIM will increase the quantity of base schedules from low- or zero-GHG resources, permitting greater amounts of high-GHG resources to be dispatched in the EIM for delivery to California without taking those GHG costs into account.

²⁷⁶ This cost would be either (1) \$12/MWh if the import was under a “specified source” contract; or (2) approximately \$5/MWh if the import was reported as an “unspecified source” delivery.

to its base schedules) and also to California (according to the EIM “deemed” delivery reports). This undermines the accuracy of California’s GHG tracking program, and may even lead to multiple entities reporting delivery of the same energy.

It should be noted that, while this scenario leads to the adverse outcomes above, it does not lead to a distorted displacement of in-state generation by out-of-state resources (*i.e.*, “leakage”). That possibility is explored in the next scenario.

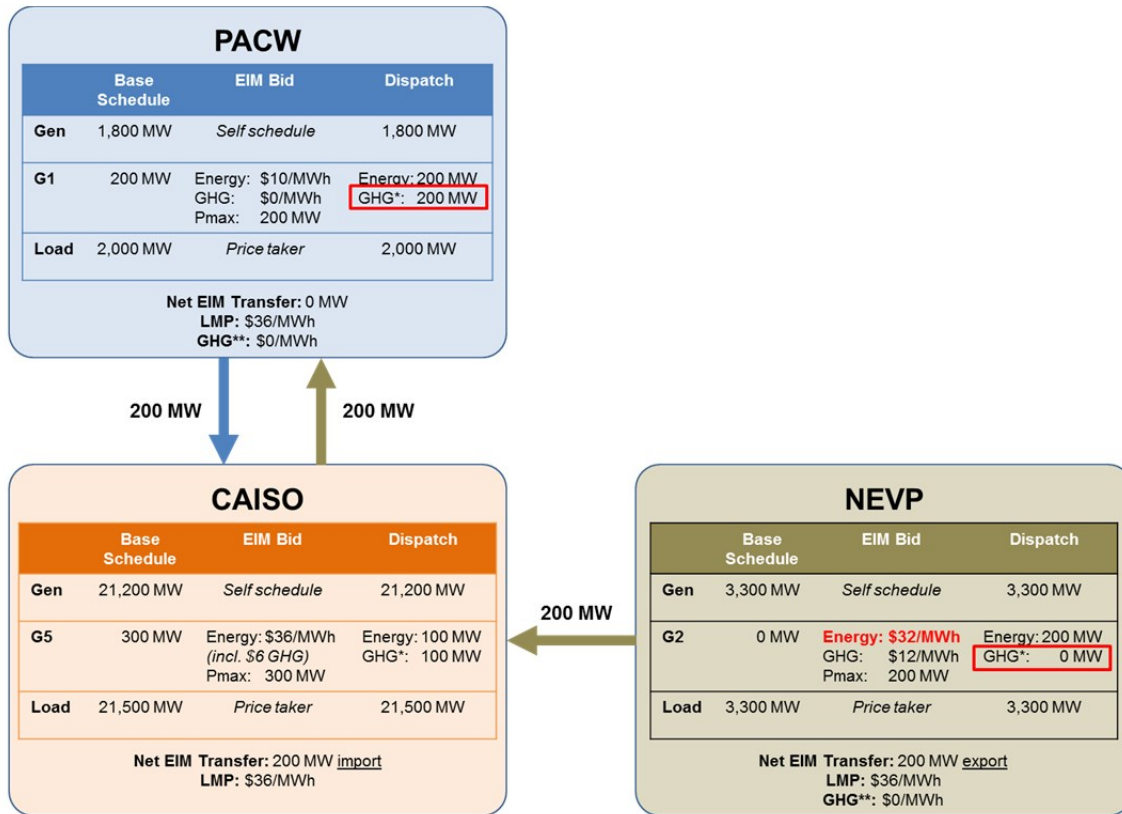
Scenario 3: Example of EIM Algorithm causing “leakage” by dispatching the wrong resource

This scenario is identical to Scenario 2, except that the energy bid price of NEVP G2 is increased to \$32/MWh (compared to \$20/MWh in Scenario 2). This means that the combined cost of energy and GHG emissions from NEVP G2 is now \$44/MWh, which is higher than the combined cost of energy and GHG emissions from CAISO G5 (which remains at \$36/MWh).

If the GHG emissions of NEVP G2 were correctly taken into account, then NEVP G2 would not be used to displace the output of CAISO G5. But if the GHG emissions of NEVP G2 are ignored, then it could appear economic to reduce the output of CAISO G5 (saving \$36/MWh) and increase the output of NEVP G2 (incurring \$32/MWh). The potential for GHG emissions to simply be “shifted” out of California to resources that are not subject to CARB’s GHG Regulations has long been recognized, and avoiding such “leakage” is an important part of CARB’s mandate. For this reason, CARB has crafted rules to ensure that the GHG emissions of imported power are *not* ignored, and the EIM must be designed to be fully consistent with those rules.

In fact, if CAISO and NEVP were the only two BAAs participating in the EIM, the EIM algorithm would not result in “leakage” in this scenario. The incremental dispatch of NEVP G2 for import into California would be evaluated as having a total cost of \$44/MWh (including its GHG adder), and the EIM would correctly recognize this as being a more costly alternative than dispatching CAISO G5, at a cost of \$36/MWh.

However, when the EIM also includes the PACW BAA and the base scheduled generation from PACW G1, the EIM algorithm is able to ignore the GHG-related costs of NEVP G2, and it does lead to “leakage,” as shown below.



* Refers to the quantity of the resource's output that is "deemed delivered" to California, and is subject to CARB reporting and compliance requirements, at the resource's GHG emission rate.
** Refers to the EIM GHG shadow price.

As with Scenario 2, there is no doubt that the incremental production from NEVP G2 is used to allow CAISO G5 to reduce its output; if there were no EIM imports serving load in California, NEVP G2 would not be dispatched at all in the EIM. In other words, NEVP G2 is clearly used to serve load in California. But also as in Scenario 2, the EIM algorithm does not assign the EIM import serving load in California to NEVP G2, but assigns it instead to PACW G1. By "deeming" this EIM import to California to be from PACW G1, the GHG cost of NEVP G2 is ignored in the EIM dispatch.²⁷⁷

This scenario leads to all of the adverse consequences discussed for Scenario 2. In addition, however, this scenario shows that the EIM algorithm for assigning GHG responsibility can actually distort the dispatch of physical generation in the EIM. In this case, NEVP G2 is producing 200 MW, whereas it should not be producing anything at all. This leads to a dispatch solution that actually entails higher total costs (resulting from the EIM dispatch algorithm ignoring some of these costs) as well as higher GHG

²⁷⁷ The least cost nature of the illustrated solution can be compared to the bid-in cost of alternative solutions. In the absence of any incremental output from NEVP G2, CAISO G5 would be dispatched to 300 MW, increasing bid-in production cost by 200 MW * (\$36 - \$32) = \$800. Alternatively, if NEVP G2 displaces CAISO G5, but is deemed to be the source of imports to California (and hence its GHG adder applies), then total bid-in production costs would increase by 200 MW * (\$12/MWh) = \$2,400 over the solution shown in the diagram. Powerex requests that CAISO confirm whether the current EIM algorithm would produce the solution shown in the graphic, and assign GHG responsibility to PACW G1.

emissions (compared to base schedules). Yet this outcome would not be reflected in reporting to CARB, which would indicate that EIM imports into California were only from non-emitting resources.

This scenario is especially problematic because NEVP G2 is actually uneconomic for sales both outside California as well as into California:

- Its energy bid price of \$32/MWh is higher than the other out-of-state resource in this example (*i.e.* PACW G1, with an energy bid price of \$10/MWh); and
- Its energy-plus-GHG bid price of \$44/MWh is higher than the other California resource in this example (*i.e.*, CAISO G5, with a total bid price of \$36/MWh).

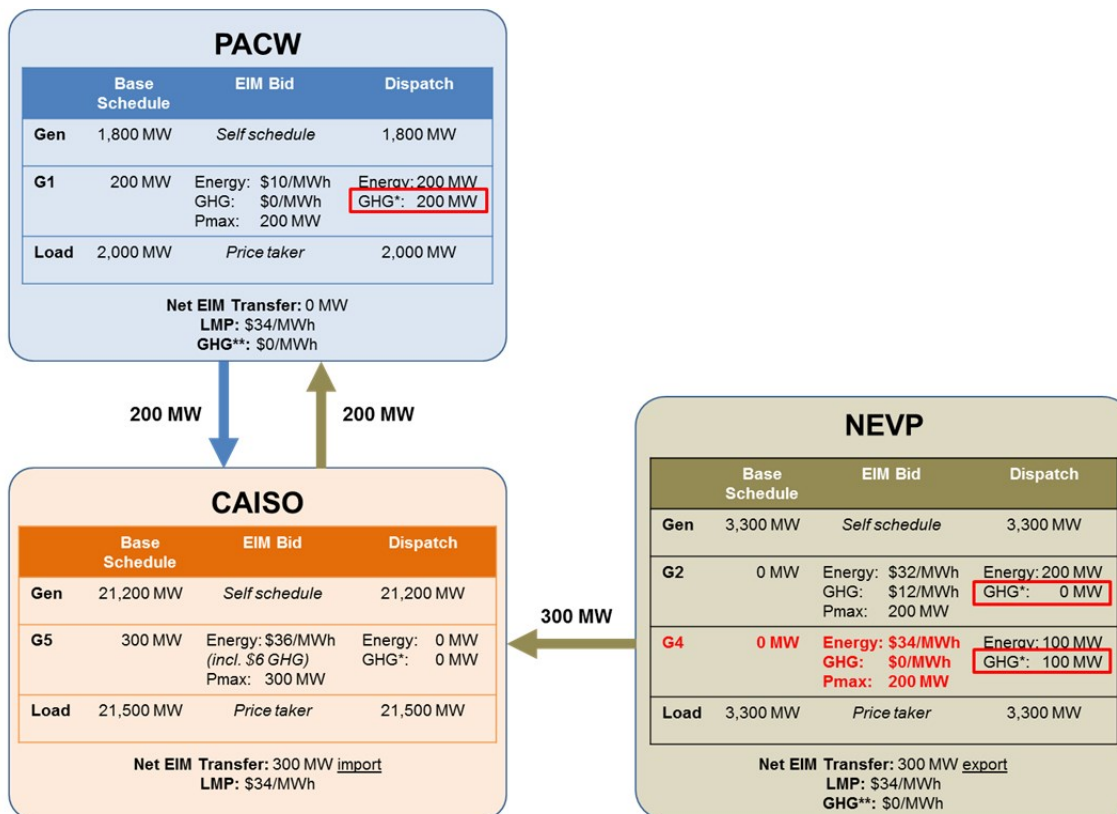
In other words, NEVP G2 cannot economically displace any other generation resource. It is *only* able to appear economic as a result of the current EIM algorithm, which dispatches NEVP G2 but avoids recognizing it as the source of energy imported into California. As a result, the EIM currently provides a unique and favorable opportunity for high-GHG out-of-state resources to make additional sales and earn additional revenue. Rather than discouraging the use of high-GHG out-of-state resources, the current EIM algorithm appears to do the opposite.

The following scenario shows that “leakage” and the favorable opportunities for high-GHG resources can occur even when lower-GHG out-of-state resources are available, and when “leakage” could be avoided.

Scenario 4: Example of EIM algorithm causing “leakage” even when a zero-GHG resource was available

This scenario is identical to Scenario 3, except that NEVP includes an additional participating resource (NEVP G4), with an incremental energy offer in the EIM of 200 MW at an energy bid price of \$34/MWh and a zero GHG adder. If the EIM consisted of only the CAISO and NEVP, NEVP G4 would be fully dispatched to displace CAISO G5, and NEVP G2 would not be dispatched at all. The inclusion of PACW—and the base schedule of PACW G1—however, leads to a different outcome in which NEVP G2 is fully dispatched and NEVP G4 is only partially dispatched. As in the prior examples, the ability of the EIM algorithm to “deem” the EIM import serving load in California to be sourced from PACW G1 allows the GHG cost of NEVP G2 to be ignored, and hence it appears to be a lower-cost resource than NEVP G4.²⁷⁸

²⁷⁸ The least cost nature of the illustrated solution can be compared to the bid-in cost of alternative solutions. Scenario 3 showed that the dispatch of NEVP G2 is a lower cost solution than the dispatch of CAISO G5, as long as GHG responsibility was assigned to PACW G1. Alternatively, if NEVP G4 were fully dispatched, then total bid-in production costs would increase by $100 \text{ MW} * (\$34 - \$32) = \$400$ over the solution shown in the diagram. Powerex requests that CAISO confirm whether the current EIM algorithm would produce the solution shown in the graphic, and assign GHG responsibility to PACW G1.



* Refers to the quantity of the resource's output that is "deemed delivered" to California, and is subject to CARB reporting and compliance requirements, at the resource's GHG emission rate.
** Refers to the EIM GHG shadow price.

This scenario, like Scenario 3, results in "leakage" of GHG emissions through the dispatch of a resource (NEVP G2) that occurs only because its GHG costs are ignored. Additionally, however, this outcome occurs *even when a lower-cost, lower-GHG resource was available for additional dispatch*. The EIM algorithm does not fully dispatch NEVP G4—even though it is more economic than CAISO G5—and instead dispatches NEVP G2 whose high GHG costs are ignored. In other words, the current EIM algorithm not only distorts the dispatch between in-state and out-of-state resources (*i.e.*, "leakage") but it also distorts the dispatch decision between different out-of-state participating resources.

As was also evident in Scenario 3, the EIM algorithm provides uniquely favorable opportunities to high-GHG out-of-state resources. Additionally, however, this scenario indicates that the EIM algorithm may also not be providing the intended favorable market opportunities for low-GHG out-of-state resources. (POWEREX)

Comment:

Aligning Accounting and Treatment of GHG Emissions between the ARB, an Expanded California Independent System Operator (CAISO) and the Energy Imbalance Market (EIM)

The ARB Staff Report highlights some inconsistencies in GHG emissions accounting associated with electricity imported into California through the Energy Imbalance Market (EIM). As stated in the report:

“[t]he EIM cost optimization model sometimes identifies zero emissions power as dispatched to California before high-emitting resources are deemed dispatched to the State when there is a load imbalance. Clean out-of-State resources (e.g., hydropower), are “deemed delivered” to California, and the Cap-and-Trade Regulation assigns the scheduling coordinator for those resources with a compliance obligation. The model’s “deemed delivered” result is treated as determining that resource as a source for a specified power import. However, in certain instances, the full transfers that support balancing load to California are not identified and accounted for in the Cap-and-Trade Program, resulting in emissions leakage.

“This inconsistency occurs when clean resources with lower deemed-delivery bid prices are selected for “deemed-delivery” to California, while higher-emitting power plants with a higher deemed-delivery bids are the actual plants dispatching to serve California load.”

The report distinguishes between “deemed-delivery” as used in the EIM algorithm and the actual resource that is dispatched to serve California load. The report further clarifies that under Cap-and-Trade regulations, ARB accounts for the total GHG emissions in California, including all GHG emissions from the electricity delivered to and consumed in the state.

ARB staff proposes to retain the current point of compliance of the CAISO participating resource scheduling coordinator, but to supplement that compliance obligation with an additional compliance obligation on entities that purchase from EIM (“EIM purchasers”) to serve load in California. As stated in the report: “the total supplemental compliance obligation for all EIM purchasers would be calculated based on the annual metric tons of CO₂e from electricity that is experienced by the atmosphere to serve California load through CAISO’s EIM, but not otherwise accounted for by emissions reported by the EIM participating resource scheduling coordinators. Each EIM purchaser’s compliance obligation will be calculated as the ratio of their EIM purchases (MWh-basis) to the total EIM load to serve California (also measured in MWh). This accounting would ensure that the full emissions associated with serving California are accounted for, and attributed entirely to entities that are engaged in serving California load.”

The ARB Should Ensure that the CAISO EIM Model is Modified to Account for GHG Imports into California Consistent with Cap-and-Trade Regulations

ARB’s proposed modification (specifically adding compliance obligations to EIM purchasers) might allow ARB to account for GHG emissions associated with imports to California, but would not address the crucial problem underlying the CAISO EIM model. It appears that the EIM cost optimization model does not assign (or consider in the model run) the accurate GHG adder to the actual resource dispatched to California.

This might result in renewable resources with no compliance obligations under Cap-and-Trade being identified as the dispatched resources (deemed-delivery) to California, while the actual California load is served by high emitting resources, which consequently will be assigned compliance obligations under Cap-and-Trade regulations.

The current design of the CAISO EIM model could result not only in higher GHG emissions in California resulting from mischaracterized imports, but also higher Cap-and-Trade compliance costs, which are ultimately borne by California's rate-payers.

The CAISO EIM model should be further developed to include the necessary constraints in order to reflect the actual resources that are selected to serve California load. (ORA)

Comment:

Out-of-state renewables are an important means of achieving the State's renewable energy goals, especially with the anticipated implementation of the federal Clean Power Plan, potential expansion of the California Independent System Operator (CAISO) Energy Imbalance Market (EIM) and grid regionalization efforts, and increasing land-use restrictions that inhibit the ability to build large-scale renewable projects in California...

In a May 2014 letter to the Federal Energy Regulatory Commission (FERC), Governor Jerry Brown and Nevada Governor Brian Sandoval said, —The Energy Imbalance Market (EIM) will help grid managers in Nevada, California, and five other states optimize renewable energy resources, balance power supplies, enhance grid reliability, and reduce power costs for customers by taking advantage of a larger, multi-state pool of geographically diverse energy resources. The new market was touted as one that would help green the electric grid, which has been an important component of California state leaders' efforts to promote policies that combat the effects of global climate change. Indeed, Governor Brown even referenced it in his January 5, 2015 inaugural address as one of many means to achieve his ambitious climate goals...

We understand that ARB staff has since identified a concern (based upon a limited set of preliminary draft data) that GHG emissions accounting for the CAISO EIM does not consider the climate impacts of —secondary dispatch resources that are being used to indirectly serve California load. ARB staff has proposed amendments in this package that would extend the accounting reach of the California GHG program to non-participating entities. If implemented, this could have a significant and chilling effect on the broader regionalization goals and its accompanying GHG reduction benefits. The potential benefits of the EIM or a broader regional market could substantially dwarf the secondary accounting impacts being proposed in the regulation.

Indeed, California Energy Commission Chair Robert Weisenmiller said at the August 10, 2016, CEC Business Meeting, "...it turns out as you get into the [ARB Cap-and-Trade] accounting stuff it becomes more and more complicated. A classic example is on the Cap and Trade Program, there's a lot of following of imports of dirty stuff into California.

There is zero accounting for renewables flowing out of California. Zero. Think about it for a second, which might be more a clean power plan. But having said that certainly most people's forecast now is there's a lot of [excess renewables] today under EIM flowing out of California. And there'll be progressively more over time, so zero is -- or ignoring it is not a particularly good approach." SCPPA strongly agrees that crediting renewables exports must be accounted for to ensure accurate accounting of the atmospheric effects associated with the electric industry's significant programmatic- and market-based contributions towards addressing climate change. This includes how to optimize the efficient use of clean electricity through the EIM. On August 26, 2016, the CAISO issued preliminary results of an EIM GHG counter-factual comparison, in response to ARB's June 24, 2016 Cap-and-Trade Program Workshop. This analysis concluded both of the following: 1) EIM dispatch reduced GHG emissions by 291,998 MTons during January-June 2016; and 2) the secondary dispatch GHG emissions associated with EIM transfers into CAISO to serve load are offset by GHG emission reductions associated with EIM transfers out of the CAISO reflecting renewable resources displacing external emitting resources. According to CAISO's analysis, the EIM construct and framework reduces GHG emission impacts that the atmosphere actually feels. This analysis should be sufficient to justify withdrawing the proposed EIM GHG emissions accounting amendments, and thereby avoiding all the associated implementation effort and costs. (SCPPA)

Comment:

The EIM Has Resulted In Significant Economic and Environmental Benefits for Entities Inside and Outside of California

The EIM is of critical value to PacifiCorp as well as other existing and future EIM participants in terms of both economic and environmental benefits. The EIM provides significant benefits to electricity customers both inside and outside of California in the form of economic, reliability, and renewable integration benefits. By accessing a wider portfolio of resources, the EIM can reduce the amount of reserves needed to maintain system balancing within an intra-hour time interval and automatically dispatch generation needed to meet future imbalances. The geographical diversity of loads and resources participating in EIM also enables improved integration of variable energy resources which can be managed more closely and at lower cost. In this way, the EIM can also facilitate the reduction of greenhouse gas emissions by enabling greater integration of renewable resources.

The CAISO quantifies benefits associated with the EIM on a quarterly basis. As of July 28, 2016, the CAISO estimated the total benefits of the EIM to be \$88.19 million from November 2014 through June 2016. Of this total, \$28.14 million in benefits accrued to the CAISO region. In addition, the EIM has resulted in overall greenhouse gas emissions reductions: a recent analysis conducted by the CAISO found that from January-June 2016, EIM dispatch reduced greenhouse gas emissions by 291,998

metric tons.²⁷⁹ These emissions reductions (and economic benefits) are largely enabled through transfers across balancing areas. In other words, if not for energy exports out of California facilitated by the EIM, some renewable generation located within the CAISO would have been curtailed. Generally, these renewable exports displace energy from higher-emitting resources outside of California. The EIM has resulted in actual emissions reductions of greenhouse gases in the Western Interconnection. Importantly, these actual emission reductions are quantified through CAISO's assessment of resource dispatch with and without the EIM and are a result of exports of renewable energy from California which displace higher-emitting resources outside of California.

Not only have emission reductions been realized from avoided renewable curtailment in California, but the EIM has allowed PacifiCorp to experience environmental benefits on its own system by enabling PacifiCorp to balance greater quantities of generation from its renewable resources. These renewable resources are not bid into the EIM but are nonetheless subject to the CAISO's five-minute dispatch for purposes of managing imbalance. Though these resources are not eligible to be "deemed dispatched" to California because they are largely flagged as ineligible to be dispatched to California²⁸⁰, the absorption of unexpected increased generation from these resources is nonetheless enabled by EIM transfers to California. PacifiCorp's wind and solar generating capacity has increased by 39 percent thus far in 2016 (compared to 2015), from 1,952 megawatts to 2,712 megawatts; PacifiCorp anticipates the addition of another 322 megawatts to come on line by the end of 2016. This year-end capacity of 3,034 megawatts is expected to constitute 29 percent of PacifiCorp's peak load. The ability to integrate this level of variable generation is in part enabled by the EIM. PacifiCorp's owned-resource emissions from January-August 2016 are 14 percent lower than the average of the previous five years for that time period, partially due to PacifiCorp's participation in the EIM and associated greater integration of renewables.

As will be described in detail below, ARB's proposals, in particular the removal of the EIM from the resource shuffling safe harbor, have the potential to significantly dampen continued interest in EIM and, in the extreme, result in entities such as PacifiCorp choosing to discontinue their participation in EIM altogether as the only way to avoid an

²⁷⁹ http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_JanJun_2016_.pdf

²⁸⁰ Oregon and Washington require compliance with their respective renewable portfolio standard (RPS) requirements through the retirement of renewable energy credits (RECs)—the definition of REC in both states includes all of the environmental attributes associated with one megawatt-hour of renewable energy. See OAR 330-160-0015(13) and RCW 19.285.030(2). Informal discussions with staff of Oregon and Washington state agencies led PacifiCorp to the conclusion that those states would consider reporting energy as zero-emitting when imported into California for purposes of California's Cap-and-Trade Program would constitute a "use" of the environmental attributes, and therefore the REC, associated with that energy. Because Oregon's and Washington's share of PacifiCorp RECs are allocated to those states for RPS compliance and must be preserved, the underlying energy is rendered unavailable for import to California.

enforcement action. Given that the EIM has already resulted in demonstrable emissions reductions, ARB should strive to avoid creating policy changes that will prevent future environmental benefits from being realized, either through greater participation in EIM or a potential future RSO...

Accounting for Emissions Associated With Electricity Imported via EIM Should Be Clearly Separate From Accounting For the Overall Environmental Effects of the EIM

In its statement of reasons, ARB continually conflates the concept of assessing the overall greenhouse gas emissions associated with the EIM, as felt by the atmosphere, with the concept of accounting for emissions associated with imported electricity. ARB refers to its exercise as reporting the “full [greenhouse gas] burden experienced by the atmosphere as a consequence of the electricity consumed in California”²⁸¹ and “full accounting of [greenhouse gas] emissions experienced by the atmosphere when there is dispatch to serve California load during periods of imbalances.”⁵

The concept of accounting for greenhouse gas emissions experienced by the atmosphere as a consequence of California load is separate from the concept of accounting for greenhouse gas emissions associated with imported electricity. Because ARB’s programs do not fully account for emissions reductions that occur outside of California, quantifying emissions associated with electricity imports does not give a full picture of the overall emissions associated with California load resulting from the EIM. While this limitation in ARB’s programs might arguably make sense for imports outside of the EIM structure which lack the operational visibility and control that comes with the EIM, it does not make sense where the EIM has been implemented. With the EIM, the CAISO has superior dispatch tracking data for the resources outside of California which are serving California load and which are being displaced by renewable exports from California. Depending on how greenhouse gases associated with imports are accounted for under the EIM, there may be an increase in emissions imported to California even while overall emissions outside of California are reduced. Accordingly, the only credible approach for greenhouse gas emissions accounting with the EIM is to consider all of these effects. Only in this manner can there be a full accounting of greenhouse gas emissions experienced by the atmosphere when there is dispatch to serve California load during periods of imbalances.

Since the time ARB issued its proposed regulations on August 2, 2016, the CAISO released a greenhouse gas counter-factual comparison of resources dispatched in EIM with a counterfactual without the EIM which precisely illustrates how emissions associated with imported electricity may increase while overall emissions attributable to EIM may decrease. As noted above, the CAISO’s study found an overall impact to the atmosphere of a reduction of 291,998 metric tons. These reductions are largely associated with renewable energy exports out of California to neighboring balancing

²⁸¹ Cap-and-Trade ISOR at 52. ⁵ MRR ISOR at 9.

areas. CAISO's study also shows that the greenhouse gas emissions associated with electricity imported via EIM were incrementally lower in some months and incrementally higher in other months. Accordingly, unless ARB accounts for emissions reductions associated with California load, it is simply not capturing the full environmental impact of the EIM. Unless ARB is considering an accounting mechanism that includes emission reductions associated with electricity exported out of California, ARB's current exercise should be more clearly focused on the accounting methodology for emissions associated with electricity imports as opposed to an assessment of the overall emissions impact of California's participation in the EIM.

Given the Challenges Associated with Accounting for Emissions Attributable to Energy Imported Via EIM, CAISO's Existing Methodology Is Reasonable

There are a number of challenges associated with accurately accounting for greenhouse gas emissions associated with EIM imports. In large part these challenges stem from the fact that, for resources outside of California, a greenhouse gas compliance cost is only incurred if load inside California is met with resources outside of California. If resources outside of California serve load outside of California, no greenhouse gas compliance costs are incurred. This dual framework creates challenges for dispatching a single footprint on a simultaneous basis. CAISO's dispatch must also accommodate participating resources that have flagged a resource as ineligible to be imported into California. As a result, the CAISO developed a methodology to "deem" certain resources as meeting California load.

ARB notes its issue with the CAISO's existing methodology as: clean resources with lower deemed-delivery bid price are selected for "deemed-delivery" to California, while higher emitting power plants with higher deemed-delivery bid may be the actual plants dispatching to serve California load.²⁸² This approach is reasonable from a market perspective in that ARB's market-based policies place a higher price on emitting resources thus communicating a policy preference to the market for cleaner resources. The consequence of placing a compliance obligation on emitting resources imported into California is to increase the cost, all other things equal, of importing emitting resources. With this policy, California is placing a preference for zero-emitting resources. Accordingly, from a market perspective, CAISO's existing methodology is reasonable because it places a preference for zero-emitting resources.

While PacifiCorp supports CAISO's current methodology, PacifiCorp also acknowledges that there may be other methodologies for capturing emissions associated with resources that are dispatched in the EIM to meet California load. PacifiCorp does not currently have a stated preference for any of the proposals regarding an alternative mechanism. However, any methodology must adhere to the principle that PacifiCorp or other EIM entity participants outside of California are not impacted by California's policies. (PACIFICORP)

²⁸² Cap-and-Trade ISOR at 52.

Comment:

The ISO supports California's efforts to reduce greenhouse gas emissions in California's electricity sector and will continue to work collaboratively with state agencies and stakeholders to advance this objective. The ISO has already developed and implemented rules in its wholesale energy market to reflect the costs of California greenhouse gas regulations in its dispatch of resources. In addition, the ISO has enhanced its energy markets and electric transmission planning activities to support California's renewable portfolio standard and facilitate the use of clean resources.

Among other efforts, the ISO's implementation of the western Energy Imbalance Market (EIM) has allowed the ISO to integrate increasing amounts of variable energy resources, including wind and solar. The EIM is an extension of the ISO's real-time market that helps balance electric supply and demand in the ISO balancing authority area as well as in EIM Entities' balancing authority areas. The use of the EIM permits other balancing authority areas to take advantage of the ISO's real-time market processes and facilitates transfers of power across the combined ISO and EIM footprint based on available transmission capability. Since its inception, the EIM has facilitated economic transfers of energy between the ISO and EIM Entities. These transfers have in part supported the operation of non-emitting clean resources. For example, in the second quarter of 2016, the EIM allowed the ISO to avoid the curtailment of over 158,806 MWh of renewable output in the ISO balancing authority area and displaced an estimated 67,969 metric tons of carbon dioxide equivalents.²⁸³ As the EIM footprint grows and more renewable resources develop in the West, the EIM will continue to facilitate these emission reductions. The ISO strongly encourages ARB to consider this fact as ARB assesses refinements to California's programs that seek to achieve cost effective greenhouse gas emission reductions.²⁸⁴

Under ARB's current cap-and-trade and mandatory greenhouse gas reporting regulations, ARB treats EIM transfers serving ISO load in California as electricity imports into California. ARB relies on the ISO's market results as reported by EIM participating resource scheduling coordinators to identify resources that supported those transfers and applies a specified source emission rate to those resources. ARB imposes reporting and compliance obligations on EIM participating resource scheduling coordinators representing these resources. The ISO and ARB collaborated on the development of initial regulatory changes to ARB's regulations to recognize EIM transfers that serve California load constitute electricity imports and that ARB would apply a resource specific emission rate to EIM participating resources supporting those transfers.

²⁸³ ISO 2016 Q2 Report Benefits for Participating in EIM dated July 28, 2016 at 7.
http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ2_2016.pdf

²⁸⁴ See California Global Warming Solutions Act of 2006, codified at California Health and Safety Code Section 38500 *et seq.*

Among the proposed amendments to ARB's cap-and-trade and mandatory greenhouse gas regulations are revisions that seek to apply additional reporting and compliance obligations with respect to EIM transfers into the ISO. These additional obligations attempt to capture the emissions associated with "secondary" dispatch²⁸⁵ to serve imbalances outside of the ISO as a result of California load taking advantage of low cost and often non-emitting resources outside of the ISO. ARB's proposed amendments appear to equate this secondary dispatches with leakage. While the ISO does not believe that all secondary dispatches represent leakage, the ISO acknowledges ARB's concern that additional emissions may be occurring to serve load outside of California as a result of the use of non-emitting or lower emitting resources outside of the ISO to help resolve ISO energy imbalances. The ISO has been and looks forward to continuing to work with ARB and stakeholders to examine appropriate means to track these emissions and to assess whether ARB needs to take regulatory action. At the same time, any solution adopted to account for emissions associated with EIM transfers into the ISO should not undermine the economic and emission reduction benefits of EIM. To do so could create additional costs to California ratepayers and increase emissions associated with ISO dispatch in a manner that contravenes the objectives of California's climate change and clean energy policies...

In its initial statement of reasons supporting the proposed amendments to the cap-and-trade program, ARB states that the ISO's market optimization results in emissions leakage in connection with EIM transfers to serve imbalances in the ISO balancing authority area.²⁸⁶ ARB's concern is that the ISO market optimization may not reflect the full greenhouse gas burden experienced by the atmosphere as a consequence of EIM transfers serving load in the ISO in a given market interval. The ISO's market optimization simultaneously minimizes total costs to serve imbalances across the EIM footprint, which includes the ISO. The cost minimization considers ISO imbalances based on energy bids and greenhouse gas bid adders and EIM Entity imbalances based on energy bids. The optimization dispatches the lowest cost resources – often non-emitting resources – to support an EIM transfer to support ISO imbalances. The optimization does not account for emissions that occur because of the associated dispatch of another external resource to serve load within an EIM Entity balancing authority area that could have been served by the resource dispatched to support the transfer into the ISO. ARB seeks to capture emissions resulting from this "secondary" dispatch to backfill the need created by the dispatch of lowest cost resources to serve ISO imbalances. Accordingly, ARB proposes to impose a new compliance obligation on

²⁸⁵ The market optimization simultaneously solves to serve load in the ISO and the other balancing authority areas in the EIM footprint. The term "secondary" dispatch is used to illustrate the backfill effect of lower GHG cost resources supporting EIM transfers to serve ISO imbalances with higher GHG cost resources serving imbalances in EIM Entities' balancing authority areas. Secondary dispatch does not mean that the market optimization has multiple distinct steps in dispatching resources to serve ISO load versus load in EIM balancing authority areas.

²⁸⁶ ARB Staff Report: Initial Statement of Reasons at 5152.

<https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

entities that purchase from the EIM to serve load in California. These entities would become electricity importers under ARB's regulations and face reporting and compliance obligations.

ARB's proposed regulatory amendments would include EIM Purchasers in the definition of electricity importers and add a new definition of EIM Purchaser as follows:

*"Energy Imbalance Market Purchaser or EIM Purchaser means an entity that purchases energy through the EIM market to either serve California load or to deliver or sell the purchased energy to an entity serving California load."*²⁸⁷

Under ARB's proposed amendments, the definition of imported electricity would include not only EIM dispatches reported by the ISO to serve electric load within the state of California but also electricity emissions distributed to EIM Purchasers pursuant to a formula that assess emissions not accounted for by the ISO's market results.²⁸⁸ ARB would calculate these emissions at a default emissions rate less emissions from EIM participating resources identified by the ISO's market as supporting EIM transfers into the ISO. The proposed language would include California load serving entities as well as market participants that operate resources supplying power in the ISO's wholesale markets in the definition of EIM Purchasers. These entities would face an emission reporting responsibility and compliance obligation associated with secondary dispatch effects in the EIM.

Unlike existing ARB reporting and compliance obligations associated with EIM transfers into the ISO, the ISO's market optimization would not reflect this secondary emission cost. As a result, the costs incurred by EIM Purchasers would not align with ISO market results. Unlike the existing ISO market design, in which resources both within the ISO balancing area and in the EIM receive a payment that reflects greenhouse gas allowance costs when dispatched to serve ISO load, EIM Purchasers would incur greenhouse gas costs without any such market payment. In addition, because the ISO's market optimization would not reflect this secondary emission cost, the optimization could dispatch resources to support EIM transfers into the ISO as economic when, in fact, the additional cost that ARB's proposed approach would impose could make that dispatch uneconomic.

Although ARB developed this proposal in part based on dialog with the ISO and other stakeholders, the ISO now believes that this approach may be problematic and proposes possible alternatives in Section III of these comments. An advantage of the EIM is that it provides transparency as to the actual resources dispatched to serve

²⁸⁷ See proposed addition of EIM Purchaser to the definitions of ARB's cap and trade regulation at 17 Code of California Regulations Section 95802.

²⁸⁸ See proposed changes to the definition of Electricity Importer and Imported electricity in ARB's cap and trade regulation 17 Code of California Regulations Section 95802 and addition of language to ARB's cap and trade regulation at 17 Code of California Regulations Section 95852.

imbalances across the combined ISO and EIM footprint and reflects the cost of dispatching those resources, including the cost of compliance with ARB's current regulation. Applying an additional emission rate to EIM Purchasers outside of the market optimization for EIM transfers to serve ISO load in order to account for a secondary dispatch would not be transparent or provide the right market signals. The ISO, accordingly, recommends that ARB not adopt the approach set forth in its proposed amendments to the cap and trade regulation...

ARB's initial statement of reasons does not adequately define or identify the magnitude of leakage that may be occurring in connection with EIM transfers.

In its initial statement of reasons for proposed amendments to its cap-and-trade regulations, ARB states:

AB 32 requires ARB to minimize emissions leakage, which is a reduction in GHG emissions within the State that is offset by an increase in GHG emissions outside the state. Leakage may occur when industry or production moves out of State in response to increased costs due to the California price on carbon.²⁸⁹

Although ARB expresses concern that its current regulation is not capturing all of the emissions experienced by the atmosphere as a result of an EIM transfer into the ISO, the initial statement of reasons does not quantify this leakage. The initial statement of reasons also does not clearly articulate how production has moved out of state in response to California's price on carbon. All EIM participating resources offering their output to support EIM transfers to support ISO imbalances are subject to California's price on carbon. The ISO's market optimization is merely selecting the most economical resource mix based on resources' energy and greenhouse gas bids consistent with the optimization's objective function to minimize total costs. As such, the ISO's market results accurately measure the emissions associated with EIM participating resources selected to support EIM transfers into the ISO.

ARB's proposed amendments seek to add a compliance obligation to account for the emissions impact of the secondary dispatch to serve imbalances in EIM Entity's balancing authority areas outside of California. While EIM Purchasers would shoulder this compliance obligation, the ISO strongly encourages ARB to consider emission reduction impacts of EIM holistically as it assesses whether it needs to take additional measures to minimize "leakage." To this end, ARB should develop a more precise definition of leakage as it applies to the EIM. Not all secondary dispatches necessarily qualify as "leakage" because dispatches of some EIM participating resources would occur economically to meet EIM load needs in an EIM balancing authority area. The ISO urges ARB to continue to discuss this issue with stakeholders.

²⁸⁹ California Health and Safety Code Section 38530(b)(1).

The ISO has completed a preliminary analysis to assess emission impacts of EIM and associated transfers into and out of the ISO balancing authority area from January through June 2016. The ISO has posted the results of this analysis on its website at the following link: http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparisonPreliminaryResults_Jan-Jun_2016_.pdf The analysis compares dispatch and greenhouse gas emissions of external EIM participating resources supporting ISO imbalances and internal ISO supply displaced by EIM transfers to the ISO. The analysis also compares dispatch and greenhouse gas emissions of internal ISO supply and external supply displaced by EIM transfers out of ISO. Importantly, without EIM, the ISO would not have visibility on the resources operating in response to ISO dispatch to even complete this analysis. This increased transparency will help assess the benefits of dispatching resources across the west and the emission profile of the combined ISO and EIM fleet of resources.²⁹⁰ The results of this analysis reflect that EIM dispatches reduced greenhouse gas emissions across the combined ISO and EIM footprint by 291,998 MTons of carbon dioxide equivalents for the period January 1, 2016 through June 30, 2016. The analysis also reflects that the secondary dispatch GHG emissions associated with EIM transfers into ISO are more than offset by GHG emission reductions associated with EIM transfers out of the ISO.

In considering whether to expand compliance obligations for EIM transfers into the ISO, ARB should consider whether EIM transfers are facilitating production of electricity out of state in response to increased costs from California's price on carbon, or if EIM transfers are offering California a greater opportunity to rely on non-emitting resources to serve its load as well as displace fossil resources in EIM Entity balancing authority areas. The latter is true and should inform any regulatory action ARB plans to take...

ARB should consider alternative approaches to track emissions associated with EIM transfers into the ISO and establish compliance obligations.

As ARB considers any appropriate regulatory action to track the emissions associated with associated with an EIM transfer into the ISO and impose a compliance obligation for those emissions, ARB should assess alternatives. Broadly, ARB should consider the following alternatives to enhance the greenhouse gas accounting associated with EIM transfers to service ISO imbalances:

Assess whether emissions associated with secondary dispatches are greater than emission reductions achieved by the EIM overall during an individual compliance year. If, based on actual data, secondary dispatches are not greater than emission reductions achieved by the EIM overall during a compliance year, ARB should not take any action. If emissions associated with secondary emissions are greater emission reductions

²⁹⁰ The ISO has committed to stakeholder to publish the emission profile associated with its dispatch and is intends to make a draft report available for public review and input during the fourth quarter 2016.

achieved by EIM during the year, ARB could reduce allowances or modify its cap in a subsequent compliance period.

- Establish a dynamic residual emission rate that the ISO can incorporate into its market optimization for the EIM. This residual emission rate or “hurdle rate” would permit the ISO’s optimization to recognize that emissions associated with an EIM transfer into the ISO include a specified source rate as well as a residual emission rate associated with a secondary dispatch. This residual rate could reflect the resource mix during a given season as well as change over time as the participating resource portfolio changes. All else being equal, this rate would make EIM participating resources more expensive than internal ISO resources and could result in the ISO’s optimization dispatching an internal emitting resource over an external non-emitting resource. In addition, this alternative would prevent the market optimization from differentiating between relative emission rates of resources with emission rates below the hurdle rate. This may result in a dispatch that increases emissions in some instances.
- In consultation with the ISO and its stakeholders, work to examine changes in the ISO optimization logic to restrain EIM transfers to only dispatches above a level that reflects an optimized dispatch of resources to serve EIM Entity area imbalances without transfers to the ISO. This approach would involve establishing an “economic base schedule” from which the ISO market optimization could then attribute EIM transfers to specific resources. Developing an economic base schedule reflects the fact that the ISO’s market systems have not optimized base schedules submitted by EIM participating resource scheduling coordinators. Under this approach, the ISO’s optimization would develop an economic set of schedules such that they are lowest cost to meet load outside of the ISO. This economic dispatch level would likely be different from the submitted base schedules because the base schedules may not be optimized in this as independently submitted by different EIM Entities. This approach would require the ISO to conduct an additional dispatch optimization pass and extensive changes to dispatch algorithm in each dispatch interval, which may not be practical or even possible within the constraints of the optimization. Finally, this approach may also reduce the efficiency of the EIM and result in additional emissions to serve California load.

The alternatives listed above identify opportunities to enhance ARB and ISO processes as well as pose potential challenges. Each has legal and regulatory risks. In some instances, the ISO would need to undertake a parallel stakeholder process to modify its market rules and obtain authorization to do so from the Federal Energy Regulatory Commission. This process could take between six and nine months. Finally, some of the alternatives also have the risks of increasing costs to ratepayers and increasing greenhouse gas emissions. To the extent ARB determines it is necessary to amend its regulations to expand compliance obligations associated with EIM transfers for the

2018-2020 compliance period, the ISO recommends that ARB consider scheduling a workshop to discuss these alternatives with stakeholders prior to proposing any revisions to the proposed amendments to its cap and trade and mandatory reporting regulations. (CAISO)

Comment:

The EIM Provides Substantial Economic and Environmental Benefits

Since November 2014, the EIM has produced substantial economic and environmental benefits for customers both inside and outside of California. By accessing a wider portfolio of resources, the EIM reduces the amount of reserves needed to maintain system balancing within an intra-hour time interval and optimizes the generation needed to meet system imbalances. The geographical diversity of loads and resources participating in the EIM enables improved integration of renewable resources which can be followed more closely and at lower cost using the EIM's wide-area dispatch model. Further, the geographic diversity of the multi-state EIM can reduce the curtailment of renewable resources, including California's, by having access to more resources capable of being displaced by carbon-free generation in real-time.

In terms of economic benefits, the California ISO ("ISO") has estimated EIM benefits to customers totaling \$88.19 million from November 2014 through June 2016.²⁹¹ In terms of environmental benefits, the ISO calculates that in the second quarter of 2016, the EIM allowed the ISO to avoid renewable curtailment of 158,806 MWh,²⁹² and that for the first and second quarters of 2016, the EIM dispatch reduced GHG emissions in the footprint by 291,998 MTons.²⁹³

These benefits are expected to grow in magnitude as new EIM entities begin participation in 2016 (Arizona Public Service and Puget Sound Energy), 2017 (Portland General Electric), 2018 (Idaho Power), and beyond.

CARB's GHG Proposed Definitions

The proposed definitions for "EIM Purchaser" and "Imported Electricity" are not consistent between Cap-and-Trade Regulations and MRR.²⁹⁴ These discrepancies lead to confusion over their meaning and how to determine compliance obligations for EIM entities.

²⁹¹ ISO EIM Benefits Report Q2 2016, http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ2_2016.pdf.

²⁹² Id at p. 7

²⁹³ Briefing on western energy imbalance market, presentation to the ISO Board of Governors August 31, 2016, by Mark Rothleder, p. 11, http://www.caiso.com/Documents/BOGBriefing_WesternEnergyImbalanceMarket-Presentation-Aug2016.pdf

²⁹⁴ Cap-and-Trade Regulation, Section 95802(a), Definitions, "EIM Purchaser" and "Imported Electricity"; MRR Section 95102(a), Definitions, "EIM Purchaser" and "Imported Electricity."

ISO's Emission Factor

The proposed MRR amendments require that the ISO annually calculate/report/verify the volume of emissions applicable to the “remaining emissions” in the EIM. An “unspecified emission factor” is used to calculate the total California EIM dispatch emissions. However, the term “unspecified emission factor” is not defined in the CARB regulations. It is unclear if this is a default emission factor used elsewhere in the CARB regulations, or is a factor calculated annually by the ISO. If the ISO calculates this factor annually, EIM entities will be unable to forecast the volume of GHG compliance obligations that will result from engagement in the EIM, short of disallowing any transfers to California. This is because the EIM entity will not control whether it is dispatched into California, and if it is, whether the dispatch is its own generating unit with a specified emissions factor or a purchase in the EIM that is dispatched from the EIM entity into California to which the ISO annual unspecified emissions factor will be applied. (EIMENTITIES)

Comment:

CARB Should Ensure that GHG Emissions Reporting is Transparent, Accurate and Does Not Foster Leakage, Contract Shuffling or Double Counting. IEP has consistently advocated over the course of the cap-and-trade program for accuracy and transparency in GHG emissions accounting. In-state generators are subject to CARB's cap-and-trade program; they are directly reporting emissions out of the stack; and, they have a corresponding compliance obligation for each covered metric ton of CO₂ equivalent. Consistent standards must also apply to those that are importing power to serve California load otherwise California risks employing a market that fosters leakage and resource shuffling.

IEP supports CARB including changes in these proposed amendments to more accurately account for GHG emissions from out-of-state resources. For example, CARB is proposing a new methodology to account for GHG emissions associated with electricity coming through the Energy Imbalance Market (EIM) to more accurately account for emissions from resources that are used to serve California's load. While IEP is not taking a position on the precision of the proposed methodology itself, IEP appreciates CARB's attempt to correct the current protocols and to ensure that all resources serving California load face similar and fair GHG compliance standards. To do otherwise ensures that in-state generators are at an extreme disadvantage in comparison to their out-of-state competitors. IEP supports modifying these methodologies where appropriate to ensure that there is a level and fair playing field between in-state and out-of-state resources and to confirm that reported emissions are representative of actual emissions. In pursuing these methodology changes, IEP recommends that the CARB keep the principles of accuracy, transparency, and emissions leakage minimization in mind. (IEP)

Comment:

One clear example of this need for interagency collaboration is the recent focus on “secondary emission effects” that result from the California Independent System Operator (CAISO) EIM optimization. On Friday, August 26, CAISO released a study demonstrating that the EIM dispatch actually displaced emitting generation for a net benefit to the atmosphere in the first half of 2016. In light of this information, JUG members do 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, thereby disrupting economic EIM dispatch, and does not take into account the net benefit to the environment of increased electricity market trading. (JOINTUTILITIES)

Comment:

SMUD does not support the proposed addition of an emission obligation for load procured through the Energy Imbalance Market (EIM). This is a carbon obligation that is simply imposed, is uncertain in quantity, and has no direct relation to the actual conscious procurement of the EIM participant. As such, it is strikingly different from any other choice in the Cap-and-Trade electricity space – when an entity procures any other electricity product, the carbon obligation is known and clear and can influence the procurement choice. This will act as a deterrent to consideration of participating in the EIM. In addition to dampening participation, an after-the-fact “uplift” charge like this is certain to distort optimization of procurement in the EIM market, since it is not a cost or factor imposed during market dispatch. (SMUD)

Comment:

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.

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.²⁹⁵ EIM participants in California should receive credit for these emissions reductions. The current proposed amendments do not address credit for emissions reductions

²⁹⁵ California Independent Systems Operator. Energy Imbalance Market GHG Counter-Factual Comparison (Preliminary Results: January-June 2016). August 25, 2016.

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 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 (PG&E)

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 (PG&E)

Comment:

ARB has identified a concern that the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) is facilitating increased GHG emissions that are not currently accounted for under the MRR or Cap-and-Trade Regulation. Specifically, emissions associated with "secondary dispatch"-generation sources that would serve California but-for the rerouting of low-emitting generation into California by the EIM dispatch algorithm. We understand that CAISO and ARB staff are working together to further evaluate this issue. However, despite the fact that ARB's analysis is based on a limited set of data, staff has proposed amendments that would extend the accounting reach of the California GHG program to non-participating entities and impose additional allowance surrender obligations (and therefore compliance costs) on certain California EDUs.

LADWP is following this issue and looks forward to additional follow up by ARB and CAISO on this important matter. LADWP has not developed a full position on the particular proposal ARB staff have briefly outlined in the short time available. However, LADWP believes that any change to the MRR and Cap-and-Trade Regulation should maintain economic incentives to invest in and generate clean energy. Changes that merely impose additional compliance obligations on entities that are generally unable to exercise sufficient control over emission sources will do little in the long-run to address this issue. At the same time, changes that discourage EIM expansion and participation could result in foregone system-wide emission reductions. LADWP believes that it is more important to develop an efficient and effective compliance program that drives substantial long-term GHG emission reductions than to ensure that every single ton of GHG emissions is ploddingly accounted for.

LADWP supports comments made by SCPA outlining why any accounting of emissions associated with secondary dispatch should also account for emission reductions associated with the displacement of out-of state emitting generation by in-state renewable energy exports. (LADWP)

Comment:

EIM Market Purchasers Should Have a Compliance Obligation Only for Electricity Deemed Delivered

The CAISO coordinates and provides operational instructions to a large number of electric power plants in order to equate supply and demand of electricity for about three-fourths of the electricity demand of residential, commercial, and industrial customers within California (the remainder is supplied by publicly-owned utilities (POUs) that are their own balancing authority, e.g., Los Angeles Department of Water and Power). As a part of its operations, CAISO facilitates a market contracting for power a day in advance

and also operates a real-time market to make up the difference between the forecasted market energy supply and demand. In 2014, CAISO expanded the real-time market to include out-of-state entities in the Energy Imbalance Market. ARB Staff has concluded that this market expansion has resulted in an incomplete accounting of the GHG emissions associated with power that serves California's load.

ARB Staff states that CAISO's EIM creates a secondary emissions effect for which EIM purchasers should have a compliance obligation, "Clean resources with a lower deemed-delivery bid price are selected for "deemed-delivery" to California, while higher-emitting power plants with a higher deemed-delivery bid may be the actual plants dispatching to serve California load."²⁹⁶

Staff's interpretation of direct delivery of renewable power without RECs is responsible for the secondary emissions effect. If direct delivery of renewables requires RECs, as in the original Board-approved regulation, then only importers entitled to claim the power as renewable would benefit, eliminating the need to track secondary dispatches. Therefore, compliance entities who participate in the EIM market should not have any additional compliance obligations for secondary emissions effects. In addition, the method for adjusting for secondary emissions (after-the-fact use of a computer model) does not meet the ARB standards for accuracy. The impact of an after-the-fact unknown uplift charge for EIM purchasers would likely reduce use of the EIM since compliance entities would not be able to control the GHG emissions of such purchases.

The CAISO EIM market optimization is guided by ARB regulations and Federal Energy Regulatory Commission (FERC) regulations. ARB regulations, as incorrectly interpreted by Staff, assign a zero GHG compliance obligation to zero GHG resources that do not have associated RECs rather than treating the emissions as unspecified or from an asset-controlling supplier. FERC requires CAISO to cap the GHG cost bid at the expected GHG compliance cost as determined by the ARB cap-and-trade regulation. The CAISO computer model then determines imported EIM energy by selecting the lowest cost out-of-State electricity willing to be deemed delivered to California and receive a cap-and-trade compliance obligation. If this is the electricity deemed delivered to California for consumption by California electric load, there should be no secondary effect considered since that is the power delivered to California.

According to ARB Staff, this accounting system is inconsistent with the requirement in AB 32 that ARB account for the total GHG emissions in the State, including all GHG emissions from the electricity delivered to and consumed in California. But it is the same GHG accounting system ARB staff has adopted for bilateral transactions by making RECs optional for specified imports. If leakage occurred, it is due to the ARB Staff's incorrect interpretation of the cap-and-trade regulation's direct delivery requirements, not the CAISO optimization process. EIM purchasers should not be burdened with secondary effects that bilateral purchasers of the same power are not. If

²⁹⁶ ISOR, page 52.

a new importer enters into a contract to buy existing large scale hydro power, the same power as might bid into the EIM market, it will have the same secondary emissions impact, yet the importer would not have an obligation for secondary emissions effects. EIM participants should be given identical treatment as bilateral purchasers. The Board should reject the Staff-proposed adjustment for secondary emissions effects. Instead, the Board should keep the current requirements for direct delivery of renewable power by requiring RECs be delivered for the power to be considered zero GHG, with changes to the GHG compliance obligation built into bids in the EIM market.

SDG&E Recommendation: The Board should reject the following proposed changes:

- The change in the definition of an electricity importer to include the EIM purchaser in section 95802.
- The CO₂e_{EIM} adjustment in the compliance obligation in section 95852 (b)(1)(B)

(SDGE)

Comment:

PGE recognizes that the current EIM GHG accounting framework likely needs to be revised; however, PGE does not believe that ARB rushing to implement a program is warranted. PGE recommends ARB consider other interim measures, such as applying the unspecified emission factor in the Mandatory Reporting Regulation for all EIM imports, while giving time for a comprehensive, sustainable solution to be developed. PGE encourages ARB to recognize the complexity of the issues in question and to allow the CAISO process to run its course. In short, PGE believes it is simply premature to move forward with the proposed Regulation, specifically with regard to the aspects related to EIM, and urges ARB to reconsider its approach. (PORTLANDGENELEC)

Comment:

EPUC opposes the amendment to modify the tracking of emissions for energy imported into the CAISO's Energy Imbalance Market. The proposal would significantly complicate the tracking of emissions in the electricity sector without any analysis of whether the magnitude of the alleged problem justifies this complication of the tracking system...

Amendment to Track Emissions from Dispatched Energy in the CAISO EIM

The amendments propose to augment the calculation of emissions attributable to electricity imported to serve California load through the CAISO's Energy Imbalance Market (EIM). The proposal would reflect in California's power prices the cost of indirect emissions created by CAISO redispatch of resources in other markets to serve California load.

The proposal is premature. While the proposal targets a conceptual problem, there is no evidence that there is actual material leakage resulting from the operation of the

EIM. ARB should begin by studying the extent of the leakage occurring today through the EIM to determine whether the value of mitigation outweighs the challenges the proposal would create. In addition, the proposal fails to specify how the secondary EIM emissions effects could reasonably be traced and accurately quantified, given the large number of transactions in the EIM. While the CAISO has roughly outlined possibilities, greater clarity is required before amending the regulation. The proposal should be pursued only when both the underlying need for and the mechanics of the proposal have been demonstrated. Staff can add certainty to the mechanics of the proposal and demonstrate that the emissions not being traced are sufficient to make any material effect on the total emissions of the electricity sector...

The Board should reject the proposal to modify tracking of emissions for the CAISO's EIM program, and direct Staff to consider the magnitude of the emissions potentially being missed and whether they represent a material part of the emissions in the electric sector warranting this significant complication of the tracking process. (EPUC)

Comment:

On that latter issue, we think it's premature to have any amendments to the regulation to address the EIM until they've been more thoroughly vetted both in the context of the magnitude of the problem, and whether the proposed fixes would even address the problem. (NCPA2)

Comment:

BPA understands that such a process will take some time and that in the meantime it might be desirable for ARB to implement a short-term fix. Such an interim solution could include all EIM designated imports being assigned the Unspecified carbon emissions rate. (BPA)

Comment:

The primary focus of our comments are in regards to the proposal to add a supplemental compliance obligation on Energy Imbalance Market (EIM) purchasers that serve load in California to address the carbon emissions related to the "deemed delivered" approach used in the current EIM algorithm. As predominantly carbon-free asset owners, the market signals, approach to dispatch, and ultimate compensation of carbon-free resources is an important consideration for our participation in the EIM and other ISO markets. PGP supports the proposed compliance obligation for California EIM purchasers as an interim step, but believes the underlying cause of the emission leakage needs to be addressed in the algorithm itself.

PGP commends the Air Resource Board for identifying and drawing attention to this issue. EIM market design rules and the associated algorithm are complex and can sometimes result in unintended consequences. The current EIM algorithm allows Participating Resources to establish a limit on the amount of resource output that can be considered "deemed delivered" to California. However, the current algorithm does

not provide the ability for a Participating Resource to designate that the deemed delivered output is *only* from incremental dispatch above the base schedule. PGP believes the current algorithm's instruction to treat base schedules as "deemed delivered" to California enables carbon leakage and creates unique opportunities for "redispatch" and market pricing in the EIM that are not available in the day-ahead or other real-time markets.

The Air Resource Board proposal to add a supplemental carbon obligation assures payment for the carbon obligation associated with the emissions leakage, however, it does not address the underlying cause of the leakage or the disparate price signals between markets, nor will it alter EIM emissions. Instead, PGP believes the EIM algorithm should be modified to allow EIM Participating Resources to designate that only the incremental generation above their base schedules be "deemed delivered." This is necessary in order to eliminate the unintended carbon leakage and market signals.

PGP requests that any action other than modification of the EIM algorithm be pursued as an interim fix with a specified date by which a modification to the EIM algorithm would be made. While the EIM emission leakage has implications for a Regional ISO, we do not wish for the solution for the EIM to be delayed until a final approach for GHG accounting in the proposed Regional ISO is defined. (PGP)

Response: Commenters express concerns about the proposed amendments to address GHG accounting related to the CAISO EIM. As stated in the Cap-and-Trade 45-day notice, the

2014 expansion of the real-time market to include out-of-State [balancing authority areas] has resulted in an incomplete accounting of the GHG emissions associated with power that serves California's load. This expanded real-time market is called the energy imbalance market (EIM) and retains the functionality of the real-time market, while making real-time market services available to other regions (California Independent System Operator 2016).²⁹⁷ The EIM cost optimization model sometimes identifies zero-emissions power as dispatched to California before high-emitting resources are deemed dispatched to the State when there is a load imbalance. Clean out-of-State resources (e.g., hydropower), are "deemed delivered" to California, and the Cap-and-Trade Regulation assigns the scheduling coordinator for those resources with a compliance obligation. The model's "deemed delivered" result is treated as determining that resource as a source for a

²⁹⁷ CAISO electricity market descriptions, accessed 6/7/2016:
<http://www.caiso.com/market/Pages/MarketProcesses.aspx>

specified power import. However, in certain instances, the full transfers that support balancing load to California are not identified and accounted for in the Cap-and-Trade Program...²⁹⁸

Without capturing the full GHG emissions associated with transfers to balance California load, the Cap-and-Trade Program is experiencing emissions leakage where the GHGs appear to be reduced within the State's accounting framework, but do not reflect real emission reductions from the perspective of the atmosphere. AB 32 requires ARB to minimize emissions leakage of this sort, as well as to accurately account for emissions associated with electricity serving California load. Again, from the 45-day notice, the EIM

accounting system is [currently] inconsistent with the requirement in AB 32 that ARB account for the total GHG emissions in the State, including all GHG emissions from the electricity delivered to and consumed in California, because the EIM cost optimization model may not in all cases report the full GHG burden experienced by the atmosphere as a consequence of the electricity consumed in California. Further, the current EIM accounting is in tension with the policy goals behind the specified source requirements of MRR.²⁹⁹

In response to the inconsistency identified between EIM accounting and ARB's mandate to fully account for the total GHG emissions in the state, staff proposed changes in the 45-day amendments to ensure the full accounting of emissions from imported electricity under the EIM. The proposed modification was the "EIM Remaining Emissions" and "EIM Purchaser" proposal that calculated a supplemental compliance obligation to be assessed on in-State purchasers of EIM energy in proportion to their use of the EIM.³⁰⁰

Upon continuing conversations with CAISO and stakeholders, ARB modified the proposed approach through amendments in the first 15-day package to move away from the concept of the "EIM Purchaser" and requiring purchasers of EIM electricity to surrender allowances for the underreported GHG emissions resulting from their share of EIM imports. Rather, these modifications now provide a method to calculate EIM outstanding emissions by determining the amount of electricity transferred into California by EIM, and multiplying that amount by the default emission factor ARB uses for unspecified market transactions, and then subtracting known emissions associated with specific EIM imports. This proposal is appropriate because this factor reflects the emissions

²⁹⁸ Cap-and-Trade "Notice of Public Hearing", August 2, 2016: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>

²⁹⁹ Ibid.

³⁰⁰ The supplemental obligation was proposed to be calculated retroactively, based on end-of-year verified emissions data.

of power plants on the margin of western electricity markets and so reasonably approximates the emissions effect of marginal changes in that market in response to California demand. For more information on the appropriateness of the default emission factor for this analysis, please see page 5 of Attachment F to the first 15-day package.³⁰¹ Based on staff's understanding of CAISO's proposal, this calculation reasonably captures GHG emissions from EIM market operations, pending further improvements to the EIM algorithm. This data can then be used to appropriately determine compliance obligations. Per the first 15-day notice, the proposal "direct[s] some unsold allowances to the Retirement Account to fully account for emissions imported through the CAISO EIM to ensure environmental and market integrity of the Program."³⁰² This interim approach will accommodate commenters who expressed concerns about any increased compliance obligation being assessed on electricity importers in California.

In the longer-term, CAISO is in the process of developing amendments to its EIM tariff and replacing its underlying GHG tracking system (i.e., implementing a two-pass solution) to address these issues. CAISO's proposed changes are reflected in its Regional Integration California Greenhouse Gas Compliance and Energy Imbalance Market (EIM) Greenhouse Gas Enhancement Straw Proposal, released by CAISO on November 17, 2016.³⁰³ This proposal is intended to more accurately capture incremental behavior, and emissions, from power plants importing power to California in response to changes in California load through the EIM market. However, these proposed changes are still being developed and will not be in place during data year 2017, and potentially not during reporting year 2018. ARB staff supports further development of CAISO's two-pass market optimization approach to provide a rigorous accounting framework.

ARB staff understands that the two-pass market optimization will operate within multiple CAISO markets, could be reflected in regional expansion designs, and may need to address multiple GHG regulatory frameworks across the West. Therefore, it is very important to carefully design the two-pass approach. ARB

³⁰¹ The ARB default emissions factor captures the emissions rate of power plants operating at 60 percent or less of capacity. Plants that operate at 60 percent or less of capacity are marginal plants, and are generally capable of modifying output to support changes in load. To support EIM transfers to serve California load, the EIM increments up plants capable of increasing output (or maintain output of plants that otherwise would decrement down). The plants economically capable of modifying output in the EIM are the marginal plants the Western Climate Initiative identified in calculating the default emission factor. Until future modifications allow direct identification of the complete emissions supporting EIM transfers, the default emissions factor is the best identification of the emissions rate of these marginal plants, and should supplement the emissions reported directly through the current deeming algorithm.

³⁰² First 15-day Notice. <https://www.arb.ca.gov/regact/2016/capandtrade16/15daynotice.pdf>

³⁰³ California Independent System Operator (CAISO), "Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal," November 17, 2016. Accessed Dec 1, 2016: <http://www.caiso.com/Documents/StrawProposal-RegionalIntegrationEIMGreenhouseGasCompliance.pdf>

intends to work with CAISO and stakeholders to ensure the final design of the two-pass solution supports accurate GHG accounting. ARB staff is aware that as CAISO works to design an implementable two-pass solution, reasonable changes to the CAISO algorithm may be needed to enable an efficient and timely optimization. ARB staff will work with CAISO and stakeholders to ensure these changes still result in a transparent and rigorous accounting structure to support ARB's implementation of California's climate and energy policies.

Some commenters misinterpreted provisions of the proposed regulation and believed they require Participating Resources Scheduling Coordinators (PRSCs) without deemed resources as being required to submit annual reports to ARB. Their 45-day comments emphasized that doing so would have a negative effect on EIM expansion. Although these comments are most appropriately directed to the 2016 MRR rulemaking, ARB staff notes that MRR does not require PRSCs without deemed resources to report to ARB (i.e., the reporting burden remains unchanged as a result of the 2016 amendments). Reporting is required from "EIM Participating Resource Scheduling Coordinators serving the EIM market whose *transactions result in electricity imports into California* [emphasis added]."³⁰⁴

To further address this continued misinterpretation in subsequent releases, the MRR reporting obligation was clarified further in the second 15-day release:

[E]ach EIM Participating Resource Scheduling Coordinator must calculate, report, and cause to be verified, emissions associated with *electricity imported as deemed delivered to California by the EIM optimization model* [emphasis added].³⁰⁵

In response to comments regarding accounting for the export benefits of EIM by crediting of exported electricity emissions against imported electricity emissions, ARB staff notes that such netting is not allowed under MRR or the Cap-and-Trade Program. This ensures that California is fully accounting for emissions from electricity whether generated in-state or imported to serve California load. ARB's regulations also do not allow the crediting of exports against electricity imported under EIM. ARB's regulations do not support this type of accounting as it would not account for emissions from electricity generated in-state which is required by AB 32.

Staff will closely monitor for evidence of generation being unintentionally-assigned a double compliance obligation through recognition in multiple markets. Staff has not seen any evidence that this may be happening, but is aware that

³⁰⁴ MRR 45-day "Appendix A: Proposed Regulation Order" p23.

<https://www.arb.ca.gov/regact/2016/ghg2016/ghgatta.pdf>

³⁰⁵ MRR Second 15-day "Attachment A: Proposed Second 15-Day Modifications" pA-11.

<https://www.arb.ca.gov/regact/2016/ghg2016/2nd15daytext.pdf>

CAISO's longer-term two pass solution is planned to allow resources to better clarify their pre-existing intent to serve California load through other contractual arrangements (e.g., resources with contracts established in the day-ahead market resulting in a resource-specific compliance obligation for serving California load are intended not to receive a deemed delivered compliance obligation on this energy when the plant is scheduled through the EIM). ARB staff will coordinate with CAISO as it works to implement the two-pass solution and propose amendments to no longer rely on the bridging methodology included in these amendments.

D-2.2. Multiple Comments

Potential Overlap with Other States' GHG Compliance Programs

The CARB regulations as drafted, pose the broad problem of possible overlap with other states' regulatory requirements. For instance, the Washington State Clean Air Rule (CAR),³⁰⁶ currently scheduled to take effect on January 1, 2017,³⁰⁷ regulates GHG emissions from certain sources including electric power generators. When sources exceed the GHG emissions thresholds established by CAR, entities become subject to the regulation and must acquire emission reduction units to cover emissions above threshold levels.³⁰⁸ The regulation does not make any exceptions for where electric power is delivered. As a result, there could be energy generated in Washington State, which is dispatched into California in the EIM, which would result in dual GHG compliance obligations under CAR and CARB. The issue associated with multiple state carbon policies overlapping without formal linkages to California is likely to become worse as states develop Clean Power Plan compliance plans and potentially their own state-specific carbon policies. As noted with respect to the CAR, regulation by the jurisdiction where the resources are located, as contemplated by the Clean Power Plan, is likely to create overlapping and double regulation which is likely to create inefficiencies and increased costs without an associated benefit. In addition, if any state adopts a program regulating electricity imports but does not formally link with California, the complexity of the EIM accounting may be significantly amplified. (EIMENTITIES)

Comment:

CAISO is just now beginning to work with stakeholders, including regulators and representatives from multiple states in the western interconnect, as well as CAISO's Market Surveillance Committee, on issues related to GHG accounting in both the current EIM and in the context of a multistate Regional ISO... Further, the same group has correctly identified the need for any GHG accounting framework to accommodate other state's programs (as they are developed for Clean Power Plan compliance or

³⁰⁶ Washington Administrative Code (*hereinafter*, "WAC") 173-442, Clean Air Rule.

³⁰⁷ The commenters understand that CARB's proposed amendments are tentatively scheduled to take effect on January 1, 2018, on a prospective basis only.

³⁰⁸ WAC 173-442-100, Emission Reduction Units.

other state level policies) on a level playing field, and not just be tailored specifically to ARB's program. (PORTLANDGENELEC)

Comment:

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. (PG&E)

Comment:

Finally, LADWP would like to note that the complicated issues raised above regarding the double regulation of imported electricity will be made even more complex to the extent ARB decides to regulate emissions associated with secondary dispatch. These emissions would be from generation sources located outside of California-often in states that do, or are expected to adopt state-specific GHG regulatory programs, whether on their own or in response to the CPP. To the extent that secondary dispatch emissions occur in states that already regulate GHGs, the Cap-and-Trade Regulation should treat those emissions in the same way emissions from sources that are actually imported into California are treated. That is, so long as those emissions are regulated by a state or federal program, they need not carry a California Cap-and-Trade Regulation compliance obligation. (LADWP)

Comment:

Importantly, ARB and CAISO should also consider any revised methodology in the context of broader energy policy trends including the development of an RSO and evolving federal carbon standards. As states in the West adopt Clean Power Plan compliance programs and/or their own state carbon regulations that may or may not link with California's program or adopt California's design elements, the complexity of developing an accounting mechanism in EIM or an RSO that efficiently accommodates all state policies may be prohibitive. Multiple state programs are also likely to result in the double regulation of emissions that would create inefficiencies in the market and increase costs unnecessarily without associated environmental benefits. The significance of these issues calls for a broader, more thoughtful joint-agency process, with both ARB and CAISO, which should consider how to harmonize these complex environmental and energy policies. ARB's current proposal falls significantly short of this objective. (PACIFICORP)

Comment:

CARB should modify the regulation to avoid double imposition of carbon costs on imported electricity

Under the current program rules, imported electricity is exempted from a compliance obligation under the cap and trade program only if the resource is located in a

jurisdiction that is fully (i.e. bilaterally) linked to California's program. CARB's proposed amendments address the possibility for more limited (one-way) forms of linkage, but do not address the impacts of such linkages on emissions obligations for imported electricity.

WPTF anticipates that other jurisdictions in the west will impose carbon regulation over the coming decade. If generating resources in those jurisdictions participate in California power markets, they could incur duplicative carbon compliance costs – once at the generator level in the originating jurisdiction and again as an import to California. Indeed, this situation appears imminent if Washington proceeds with its proposed Clean Air Rule in 2017, and because Puget Sound Energy becomes an EIM entity, which is on track to occur as of October 1, 2016. Any double imposition of carbon costs will undermine the efficiency gains of electricity market integration, further distort dispatch and provide a strong disincentive for external resources to participate in the EIM or a regional ISO.

For these reasons, WPTF recommends that CARB develop provisions that enable electricity importers to reduce the emissions obligation associated with imported electricity by an amount commensurate to the carbon costs incurred for that electricity in the other jurisdiction, regardless of whether that jurisdiction is formally linked to California. (WPTF)

Response: Commenters request modifications to take into account other jurisdictions' GHG programs. ARB staff cannot implement a revision to current EIM GHG accounting in response to other jurisdictions' GHG programs that are not currently incorporated, or in active process to become incorporated, into the EIM optimization algorithm. Therefore, ARB staff did not develop provisions regarding reducing an entity's compliance obligation for electricity deliveries due to such entity's carbon costs for such deliveries incurred in another jurisdiction. If other jurisdictions develop programs that integrate carbon costs for electricity serving their load, ARB will consider these issues and changes to EIM GHG accounting as warranted.

Miscellaneous

D-2.3. Comment

Valley Electric offers some overall comments, written collectively for the policy making processes in both the cap and trade and the MRR program. They are written collectively because collectively the policies, coupled with their implementation, are falling short of achieving reasonable outcomes with respect to serving non-California load through the California (CAISO). In these comments, we discuss the problem and offer several remedies for CARB's consideration in its 2016 policy changes, remedies which include (1) adding provisions to allow entities serving non-California load through the CAISO an ability to balance their loads and resources without the full burden of presumed sourcing from, and sinking in, California, and (2) issuances of a small number of allowances to

offset ARB carbon costs being imposed on non-California load being served through the CAISO.

Problem Definition: CARB policies do not properly address the service of non-California load through the CAISO.

There are several ways in which the existing policies and frameworks improperly treat non-California load.

CAISO Tagging Methods and Market Model assume imports only for California load and exports only from California Generation

When cap and trade came into effect, the Energy Imbalance Market (EIM) did not exist. The convention adopted by CARB via cap and trade and MRR assigned responsibilities for imported power based on scheduled power flows (e-tags.) Under this approach, all CAISO load is effectively considered to be California load. With the inception of the EIM, CARB modified its regulations to address power imported to the state via the EIM. Imports to California under the EIM are not identified based on schedules, but are instead attributed to California load based on an algorithm that recognizes that not all energy being used in the EIM is flowing to California load. With discussions of a regional power market, there is growing awareness that the existing regulatory provisions for accounting for electricity imported into the state and associated emissions will not work in a multi-state market. Specifically, as the CAISO indicates in its recent Regional GHG issue paper, the approach currently used for accounting for imports in the day-ahead markets based on e-tags will not work within a multi-state balancing authority model.³⁰⁹ In fact, the CAISO already operates as a multi-state balancing authority; it has since VEA joined the CAISO as an LSE and a PTO in 2013. The CAISO indicates in its paper that it operates a single balancing authority even with the participation of VEA.³¹⁰

CARB's current accounting rules treat all external supply scheduled into CAISO in the day-ahead and real-time markets as serving California load, and thus subject such supply to obligations under the cap and trade and reporting regulations. Because the CAISO market model does not distinguish between delivery points within the state boundary, and delivery points outside the state, there is no mechanism within CARB's current e-tag based accounting scheme to either (1) recognize that VEA's energy flowing through the CAISO market does not all go to California and (2) recognize that some of the energy serving VEA's CAISO market purchases comes from outside of California. The CAISO in its regional paper recognizes this.³¹¹

³⁰⁹ Regional Integration California Greenhouse Gas Compliance issue paper, CAISO, August 29, 2016 (<http://www.caiso.com/Documents/Issuepaper-RegionalIntegrationCaliforniaGreenhouseGasCompliance.pdf>), p.3).

³¹⁰ *Id.*, FN 9.

³¹¹ *Id.*, p. 10.

As a result, VEA has to pay a carbon premium for energy delivered *through* the CAISO market and into Nevada. This is in direct opposition to legislative and regulatory intent that only imported electricity that serves California load be subject to carbon obligations.³¹²

VEA's service through the CAISO is only to serve its Nevada load, yet VEA is exposed to carbon costs through the CAISO and through CARB

VEA's deliveries to the CAISO are only intended to serve its non-California load: before VEA joined the CAISO it imported no electricity into the CAISO. VEA has no business model to import energy to the CAISO for profit; VEA makes best efforts to reduce any residual energy absorbed by the CAISO net of its load and to minimize purchases from the CAISO, and from a physical point of view, any residual energy of VEA's most likely never flows to California.

VEA is subjected to carbon costs for energy delivered through CAISO for its Nevada load but does not receive allowance allocations to compensate its customer for these costs

CARB provided no carbon allowances to VEA to relieve the costs associated with servicing its Nevada load from energy imported to and delivered through the CAISO. Whereas CARB provides allowances to offset the costs of the cap and trade program on California retail customers, CARB provides no allowance value to offset the carbon costs for VEA's Nevada customers. Thus, VEA bears the burden of the full carbon costs for energy that service VEA's Nevada load from the CAISO market despite that the regulations call for excluding carbon charges if such energy was imported.

GHG accounting rules discriminate against non-California load served through the CAISO relative to non-California load served through the EIM, and relative to California load served through the CAISO

CARB's current GHG accounting rules directly discriminate against non-California load being served through the CAISO. VEA is being discriminated against vis-à-vis other entities in two respects.

1. For EIM Participants, there is recognition of, and accounting for the reality that, the service of the participants' imbalance through the CAISO market at times comes from an out-of-state resource that does not bear the cost of carbon. Because VEA

³¹² CARB's existing definition for imported electricity reads: "Imported Electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. ... Imported electricity does not include electricity imported into the CAISO balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the state of California." Section 95802 – Definitions.

participates in the CAISO, rather than the EIM, CARB assigns a carbon obligation for every MW that serves VEA's load whether or not it came from a California source.

2. For other load served by CAISO, CARB has provided allowances to offset the cost impact of the cap and trade program to retail end users.³¹³ CARB is treating VEA as a covered entity for its service of its Nevada load, yet CARB has not provided any allowances to VEA to offset the carbon costs on its customers that are being imposed in the service of its Nevada load³¹⁴ through the CAISO even though CARB policies call for such allocations.³¹⁵

It is not just nor is it good policy for California to continue to impose carbon costs in this way on an entity serving non-California load through the CAISO. To continue to not find a remedy is squarely in the face of the intent of the cap and trade program and perpetuates discrimination toward one small entity that chose to be a first-mover in the movement of regional efficiency.

The improper treatment and disparity must be remedied at this time

VEA, a small electric cooperative, was the first mover in what is now clearly acknowledged as path to improved efficiency and ultimately to reductions in the West's carbon emissions via a regional energy market. CARB would not have expected those forming the EIMs to pay carbon costs on all the MWs that are served through the CAISO-run markets. Similarly, it would be very inappropriate to charge carbon on all the MWs served through the ISO-operated regional market.

There seems to be some presumption on the part of CARB that VEA receives some benefit from participating in the CAISO market that should make it worthwhile for VEA to pay these costs; however, such a standard is not imposed on EIM members, nor is it expected to be imposed on other regional participants.

VEA finds it inconceivable that CARB would continue to treat VEA in such a discriminatory and inappropriate manner. The CAISO also believes that a remedy should be found as soon as possible.³¹⁶

³¹³ See for example CARB's Final Statement of Reason related to allocation of allowances, which noted a main driver of the allocation recommendation was to offset costs for customers/ratepayer cost burden. (See for example p. 5 of Appendix A, Staff Proposal for Allocating Allowances to Electric Distribution Utilities, dated July 2011.) Note that there is no indication that only California Electric Distribution Utilities merited allowances and that the customers of non-California utilities are expected to bear the costs of California's cap and trade program.

³¹⁴ VEA historically has received a very small number of allowances for its approximately 1 MW/hour of California load. VEA's allowance allocation did not increase with CARB covering its service of its Nevada load through the CAISO.

³¹⁵ See Section 95890- General Provisions for Direct Allocation, part (b) states that "an electric distribution utility that is a covered entity shall be eligible for direct allocation of California GHG allowances ...".

³¹⁶ CAISO comments regarding the Public Workshop on Potential 2016 Amendments to the Cap-and-Trade Regulations and California Plan for 111(d) Compliance, dated October 19, 2015, pp. 1-2.

CARB has told VEA in the past that it has to follow its existing policies and must make VEA report in the way that CARB has directed. Yet as described above, CARB's directives cannot ensure that CARB is not violating its own existing policies.³¹⁷ CARB has also indicated that it could address these disparities in this upcoming rulemaking. The time is now.

Remedies are available

VEA believes the ultimate remedy is for CARB to work with the CAISO to revise the market design to be robust to account for California and non-California load. In the interim, CARB has several options to remedy the inappropriate treatment of VEA, all of which would be consistent with the goals of the cap and trade and reporting regulations. That is, none of the changes VEA is requesting are intended to avoid any net carbon obligation or to advantage VEA relative to other CAISO participants or CARB covered entities.

VEA is submitting comments in response to both the cap and trade policies and the MRR policies with alternative approaches in the respective comments. VEA requests the following revision be made to accommodate non-California load participating in the CAISO.

The staff has proposed explicit provisions of netting in Section 95111(12)(D) as follows: "(D) Netting of electricity across intervals is prohibited in the calculation of reportable CAISO sales. Excess electricity sold into the CAISO markets in any interval cannot be netted against the electricity purchased from the CAISO markets a different interval." To the extent CARB is not in agreement that VEA's CAISO transactions should be exempt entirely from compliance obligations until such time as a regional market and compliance design does not create an burden for those serving non-California load through the CAISO that well exceeds their incremental carbon impact in California, VEA requests that this additional provision be included in the staff-proposed part (D):

"Netting of electricity across intervals is permitted in the calculation of reportable CAISO sales as follows for entities serving non-California load. Excess electricity sold into the CAISO markets in any interval cannot be netted against the electricity purchased from the CAISO markets at different interval within the same year to the extent that netting does not exceed 10% of the entities' annual non-California load served through the CAISO."

Allowing such entities to net up to 10% of their non-California load provides some ability to the entities to balance their load in the CAISO, and it recognizes that not all excess electricity provided back into the market serves California load. Even with such a netting proposal, any deliveries to the CAISO markets in excess of the entities' non-California

³¹⁷ Both because when there are imports used to serve VEA's imbalances they are not being exempted from carbon and VEA is not receiving this benefit. Also because CARB has developed policies that are intended to provide allowances to those retail end users covered by the policies, yet CARB has instructed VEA to report for its Nevada load yet provides those retail customers no allowances.

load - when measured over the year - would be subject to a carbon obligation. Thereby, such a modification will not result in any net deliveries to the CAISO markets being exempt from carbon accounting.

VAE urges CARB to consider carefully the comments herein and to take action to remedy the improper application of CARB's policies to VAE, the first non-California/non-EIM participant in the CAISO's expanding regional market. (VALLEYELECTRIC)

Response: The commenter reiterates comments expressed in previous amendments to the Cap-and-Trade Regulation, and these specific requests have been previously addressed in staff's responses to comments I-40 and I-41 in the 2011 Final Statement of Reasons, which was included as a reference to the ISOR of this rulemaking. Moreover, since modifications to these provisions have not been proposed as part of this rulemaking, the comments are outside the scope of this rulemaking. Notwithstanding this, staff notes that the commenter is only assessed a compliance obligation for electricity that serves California load and not electricity that serves load in Nevada. In this respect, the commenter is treated identically to all others in the program that serve load in California.

D-2.4. Comment:

The proposed amendments would also make the ISO a reporting entity under the regulation and attach specific verification requirements for submitted data. ARB's initial statement of reasons supporting the proposed changes to the mandatory greenhouse gas regulations provides:

"Staff is proposing to include CAISO as a reporting entity for electricity imports data related to transfers within the EIM. In previous years, this type of data was acquired through a formal subpoena process. Since the EIM may not be providing ARB or its participating members, some of which are reporting entities under MRR, all of the data to support full accounting of GHG emissions experienced by the atmosphere when there is dispatch to serve California load during periods of imbalances, staff worked with CAISO to identify the additional type of data that would be needed to support full GHG accounting. As this data will be provided by CAISO directly and used in the cap-and-trade program to assess compliance obligations, the timeliness and verification of the data must be the same as other data collected for the same purpose."³¹⁸

ARB's proposal to make the ISO a reporting entity under its mandatory greenhouse gas reporting regulation creates unnecessary regulatory requirements for the ISO. Under AB 32, ARB has authority to require reporting from greenhouse gas emission sources.³¹⁹ The ISO is a market operator and transmission planning entity. In conducting these activities, the ISO is not a source of emissions. Although the ISO may

³¹⁸ ARB Staff Report: Initial Statement of Reasons at 9.

<https://www.arb.ca.gov/regact/2016/ghg2016/ghgisor.pdf>

³¹⁹ ARB Staff Report: Initial Statement of Reasons at 10-11.

<https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

have possession of market data that may assist ARB implement its regulatory programs, the ISO is not appropriately a reporting entity under ARB's regulations. Moreover, the proposed changes to ARB's mandatory greenhouse gas reporting regulations would require the ISO to have its market data verified by a third-party that meets specified requirements.³²⁰ This proposal would impose an undue burden on the ISO and there is no justification for doing so ARB does not explain why it cannot use existing processes – including its subpoena authority - to obtain ISO market data. As such, the ISO objects to ARB's proposal to make the ISO a reporting entity under the mandatory greenhouse gas reporting regulation. (CAISO)

Response: The CAISO reporting provisions raised by commenters are outside the scope for this rulemaking as those provisions are contained in MRR. This issue is addressed in the 2017 FSOR for the Mandatory Greenhouse Gas Reporting Regulation. Regardless, ARB staff notes that in the second 15-day amendment package for MRR, staff removed CAISO as a reporting entity under MRR and instead will receive the necessary information from CAISO through an annual subpoena process.

D-2.5. Multiple Comments

Lastly, BPA urges the ARB to ensure consistent and equitable treatment of electricity imported into California across all electricity markets. This should include the continued application of the Safe Harbor provision to all short-term transactions, including EIM dispatch and algorithmic GHG compliance obligations. (BPA)

Comment:

The Board should also reject Staff-proposed changes to the resource shuffling provisions. As a market, neither sellers nor buyers are determining whether particular electricity is deemed delivered to California. It is the ARB rules, the FERC rules, and the CAISO optimization that are responsible for any leakage that occurs as a result of the shuffling of resources deemed delivered to California; therefore, the first deliverer should not be held responsible.

SDG&E Recommendation: The Board should reject the following proposed changes:...

- The additions to section 95852(b)(2)(A)(10). (SDGE)

³²⁰ See proposed addition to section 95111(h)(2) and (3) of ARB's mandatory reporting regulation, which states in relevant part:

(2) CAISO will report the following information:

(A) Annual sum of the "remaining emissions" calculated in section 95111(h)(1); (B) Names of entities meeting California imbalances from EIM transfers and annual quantity of purchased MWh for each entity based on 5 minute interval data;

(3) The data provided in 95111(h)(2) must be verified per section 95103(f).

Comment:

WPTF also strongly opposes the new language that excludes power deemed delivered through the EIM from the resource-shuffling exemption for short-term contracts. As discussions around the EIM GHG accounting clearly illustrate, the assignment of generation to California and associated emissions is a function of the algorithm and market conditions – not the actions of any particular market participant. To suggest that EIM market results constitute resources shuffling is therefore completely inappropriate, and will hinder participation of external resources in the EIM. (WPTF)

Comment:**CARB Should Not Remove the EIM From the Resource Shuffling Safe Harbor**

Entities participating in the EIM have little or no control over how resources are dispatched in the EIM or how resources are deemed delivered to California. CAISO dispatches resources in the EIM—regulated entities have no ability to “shuffle” their resources to intentionally avoid a compliance obligation. However, because CAISO is not regulated under the Cap-and-Trade Program, removing the EIM from the resource shuffling safe harbor creates significant uncertainty regarding how the prohibition of resource shuffling in EIM would be enforced, both for existing and future EIM participants. This is likely to dampen continued and future participation in the EIM as well as a future RSO. Given the lack of control that entities have over dispatch in the EIM or a broader regional market, the concept of resource shuffling should be reconsidered entirely in this context and should be rejected for purposes of the EIM or an RSO.

PacifiCorp understands that the ARB is including this amendment as a “placeholder” for further discussion; however, this approach for proposing regulatory amendments is extremely problematic. At the very least, this method of establishing regulations fails to meet the necessary notice and comment provisions required as a fundamental principle of administrative law. ARB indicates that this change provides notice that ARB will continue to work with CAISO and stakeholders to ensure any final accounting method for emissions associated with load imported to serve California through EIM transactions does not pose a conflict with prohibitions to resource shuffling, which would result in the possibility of emissions leakage.³²¹ It is unclear why, if ARB’s intent is to begin a dialogue around the definition of resource shuffling in EIM, it was necessary to take the extreme approach of proposing to remove EIM from the resource shuffling safe harbor. Assurance from ARB that it does not intend to enforce this provision as drafted fails to provide the necessary policy direction needed for regulated entities to make informed decisions to avoid being in violation of the rules the ARB ultimately decides to implement. Regardless of ARB’s stated intent, this proposed change creates significant uncertainty for existing and future EIM participants and an unknown and unknowable

³²¹ Cap-and-Trade ISOR at 156.

burden on market participation. ARB should not propose such amendments, even as a “placeholder,” without a full understanding and explanation of the potential market impacts and the potential negative environmental impacts in the form of increased greenhouse gas emissions associated with decreased participating in the EIM. (PACIFICORP)

Comment:

Additionally, it is unnecessary to remove the resource shuffling exemption for economic bids or self-schedules submitted to the EIM. 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. (PG&E)

Comment:

Exposing EIM Participants to Accusations of “Resource Shuffling” is Unnecessary and Harmful

In addition, under the Proposed Amendments to the GHG Regulations, EIM participants could be exposed to accusations of violating CARB’s regulations by engaging in “Resource Shuffling,” which could carry serious consequences. In the context of the Cap-and-Trade Regulation, “Resource Shuffling” means, in part, “any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation.”³²² Resource Shuffling is prohibited and a violation of the Cap-and-Trade Regulation.³²³ Currently, Resource Shuffling does *not* apply to deliveries “resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time market.”³²⁴

The Proposed Amendments to the GHG Regulations include a modification to the above list of activities that do not constitute Resource Shuffling. Specifically, the draft proposes to eliminate safe harbor protections for deliveries resulting from a bid that clears the EIM.³²⁵ Powerex strongly opposes this proposal as both harmful to the EIM and ill-suited to addressing CARB’s concerns.

As Powerex understands the proposed regulation, EIM participants could potentially be exposed to claims of having engaged in a “plan, scheme or artifice” as a result of the manner that the EIM determines each resource’s “deemed deliveries” to California, because the deemed delivery outcome of the EIM algorithm could result in a lower-GHG

322 As per § 95802(336) of California Cap On Greenhouse Gas Emissions And Market-Based Compliance Mechanisms 21 Id. at § 95852(b)(2)

³²³ Id. at § 95852(b)(2)

324 Id. at § 95852(b)(2)(A)(10).

325 As per § 95852(b)(2)(A)(10) of *Appendix A – Draft Staff Report: Initial Statement of Reasons - Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation*

source being substituted for a higher-GHG source. This potential liability exposure is inappropriate, as the “deemed deliveries” are the result of the EIM algorithm, and not the result of any dispatch or reporting discretion exercised by EIM participants. Moreover, because the “deemed delivery” determinations are entirely out of the EIM participant’s control, there is nothing that an EIM participant can do to ensure its EIM transactions are *not* found to constitute Resource Shuffling under CARB’s regulations. To protect against this risk, EIM participants would need to elect to not permit *any* of their output to be deemed by the EIM algorithm to serve load in California, or avoid participating in the EIM altogether. Both outcomes would reduce the efficiency and economic benefits of the EIM, and would also restrict the opportunities for the EIM to substitute GHG-emitting production within California for lower- or non-emitting production that may be available outside of California, and thus would not be consistent with the goals of the CARB programs.

The proposed changes to the provisions regarding Resource Shuffling merely expose individual reporting entities to potentially being held liable for the flaws of the EIM algorithm, but do not address the root of the problem, as discussed in more detail elsewhere in these comments. The proposed removal of EIM transactions from the Resource Shuffling safe harbor is unnecessary, inequitable, and is likely to undermine the other economic benefits provided by the EIM. Powerex urges CARB to eliminate the changes to the Resource Shuffling provisions from its proposed amendments...

Moreover, Powerex also urges CARB to strike the proposed categorical removal of EIM transactions from the “Resource Shuffling” safe harbor that it currently applies to all other short-term and CAISO market transactions. (POWEREX)

Comment:

ARB also proposes to modify the safe harbor provisions associated with the prohibition against resource shuffling to exclude the EIM.³²⁶ These provisions also create uncertainty and are internally inconsistent. First, ARB’s initial statement of reasons provides that ARB is removing the resource shuffling exemption for economic bids or self-schedules that clear the ISO real-time market.^{327,328} This language creates uncertainty because it suggests that economic bids or self-schedules that clear the ISO’s real-time market constitute resource shuffling when they clearly do not. Resource shuffling, as defined by ARB, is a “plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation.”³²⁹ ISO market dispatches do not meet this definition because they are not a plan, scheme or artifice undertaken by a first deliverer

³²⁶ See proposed changes to cap and trade regulation section 95852(2)(a)(10).

³²⁷ ARB Staff Report: Initial Statement of Reasons at 156.

<https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

³²⁸ California Code of Regulations at Section 95802(a)(336).

³²⁹ Ibid.

of electricity. In addition, the proposed regulatory changes are internally inconsistent because they state that electricity imported through the EIM is not exempted from resource shuffling provisions but maintain a safe harbor from the prohibition against resource shuffling for ISO real-time market transactions. The EIM is the ISO's real-time market extended to other balancing authority areas in the West. The ISO recommends ARB not adopt the proposed changes to the resource shuffling safe harbor provisions of its cap-and-trade regulation. (CAISO)

Comment:

PGE's primary concern in the proposed Regulation is the removal of the current safe harbor for short term transactions with regard to resource shuffling. PGE believes the existing resource shuffling exemption for short-term sales is appropriate given the nature of the short-term markets. PGE is concerned that the proposed change to the current compliance framework would introduce unavoidable compliance risk for EIM participants. Under the current EIM design, EIM participants have little control over resource dispatch in the real-time markets following their hourly base schedule submittals and thus have little control over the manner in which the resources are deemed delivered to California. Opening the possibility for an EIM participant to inadvertently violate a resource-shuffling regulation could serve as a disincentive for market participation, particularly for entities that have a significant quantity of carbon-free resources in their resource portfolio and therefore have increased exposure. (PORTLANDGENELEC)

Comment:

Resource Shuffling Requirement Causes Regulatory Uncertainty and Risk

The EIM Entities oppose the proposed language in the GHG Proposal stating that the short-term resource shuffling exemption³³⁰ does not apply to the EIM. EIM entities have limited control over resource dispatch in the real-time markets following their hourly base schedule submittals and thus, have little control over the manner in which the resources are deemed delivered to California. Therefore, an EIM entity could be deemed to be in violation of the requirement through normal and rational participation in the market, which heightens the regulatory risk. The existing resource shuffling exemption for short-term sales is appropriate given the nature of the short-term markets. Removing the existing resource shuffling safe harbor for short-term sales would increase the compliance risk of participating in the real-time markets and may result in a significant reduction in EIM participation.

Additionally, the GHG Proposal does not describe the factors that CARB will use to determine that an EIM transfer is considered resource shuffling, which prevents EIM entities from being able to control compliance regulations, even if they could control transfers. The market dispatch of the EIM removes control from EIM entities to

³³⁰ GHG Proposal at p. 125.

determine when and where a dispatch will flow once made available to the market, which prevents EIM entities from being able to control compliance with the regulations and creates a regulatory risk. This uncertainty and lack of control could lead to reduced liquidity or participation in the EIM if entities decide not to join, not to bid in, or not to flow energy to California. (EIMENTITIES)

Response: Commenters object to the 45-day amendment that proposed to remove EIM from the resource shuffling safe harbor provisions. In the second 15-day package staff reinstated the EIM safe harbor because the concerns of resource shuffling are being addressed in the short term by the bridge solution in the proposed amendments, and in the long term by the two-pass solution that being developed by CAISO. Under the bridge solution, the retirement of allowances for emissions reported by the EIM Participating Resource Scheduling Coordinators, and the additional retirement of allowances for EIM Outstanding Emissions ensures the full atmospheric effect of California's EIM imports are accounted for. For a full description of the EIM bridge solution, see staff's response to the 45-day comment D-2.1. Staff believes this modification addresses the commenters' concerns. In the longer term, ARB intends to engage with CAISO and stakeholders to ensure the two-pass optimization aligns with a rigorous accounting framework needed to support the State's climate programs.

D-3. Renewable Portfolio Standard (RPS) Adjustment

Opposition to Removing the RPS Adjustment

D-3.1. Multiple Comments:

Key Theme: Regulatory certainty is necessary to guide investment and recognize ongoing utility efforts to reduce emissions, such as the RPS Adjustment and Voluntary Renewable Energy Program. Utilities plan for investments and infrastructure far into the future, as do many other California businesses. Regulatory certainty is necessary to ensure that early investments and ongoing planning decisions are made in line with the right economic incentives.

The most pressing need for regulatory certainty in this proposed regulation is the proposal to remove the Renewables Procurement Standard (RPS) Adjustment sections of the Cap-and-Trade and Mandatory Reporting regulations (MRR). The RPS Adjustment is a critical cost mitigation element of the Cap-and-Trade Program for any utilities. By reducing the compliance obligation of Californians based on the renewable firmed and shaped electricity being brought from out of state to help meet California's RPS requirement, the program recognizes the investment Californians have made in renewable energy and the associated GHG emissions reductions... (JOINTUTILITIES)

Comment:

SMUD also supports the comments filed by the Joint Utility Group, covering the following key themes:

- Regulatory certainty is necessary to guide investment and recognize ongoing utility efforts to reduce emissions, such as the RPS Adjustment and Voluntary Renewable Energy (VRE) Program...

(SMUD)

Comment:Revisions to the RPS Adjustment for the Post-2020 Period

ARB has proposed to remove the RPS Adjustment altogether and instead allocate additional allowances to EDUs as part of the post-2020 cost-based allowance allocation methodology. However, as outlined in more detail below, this proposed approach is inadequate for the following reasons:

- while an EDU's imported firmed/shaped electricity may increase over time, the allocation will decline over time due to the cap adjustment factor;
- POUs with grandfathered long-term contracts are permitted to meet a larger percentage of their RPS obligation with firmed/shaped renewable electricity than the proposed methodology takes into account;
- the proposed allocation method does not take into account differences in the volume of imported firmed/shaped electricity between utilities, and
- the proposed allocation method does not make allowance for new contracts for imported firmed/shaped RPS eligible electricity.

Therefore, LADWP recommends that ARB retain the RPS Adjustment for the post-2020 period. Any post-2020 RPS Adjustment should, as outlined above, ensure that the owner of RECs associated with RPS-eligible firmed/shaped power (and only the owner of such RECs) can claim the RPS Adjustment credit to offset reported GHG emissions

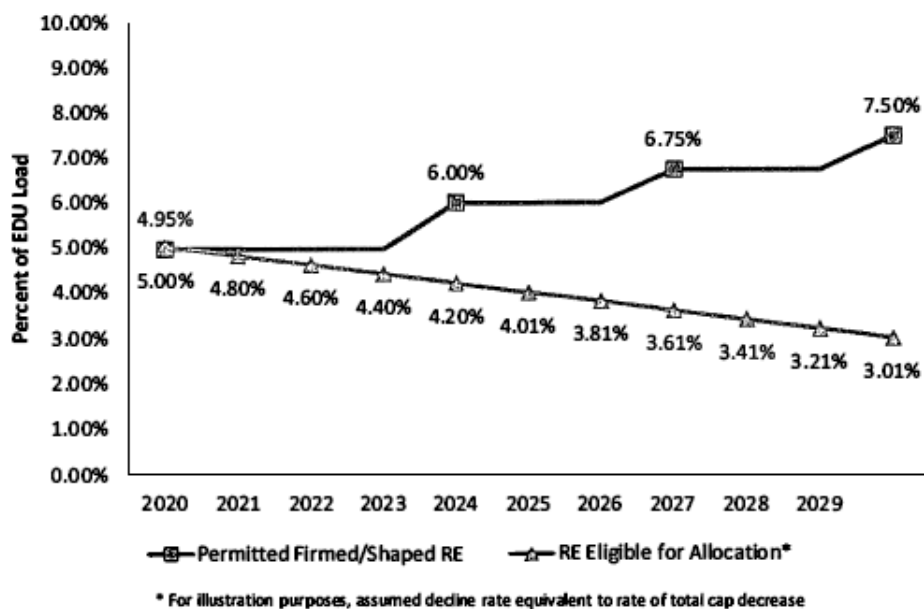
ARB Should Retain the RPS Adjustment

ARB's proposed methodology for allocating allowances is not sufficient to address the increased compliance costs that would result from the elimination of the RPS Adjustment.

ARB has not designed its allowance allocation methodology to provide an allowance for every ton of GHGs associated with MWhs of firmed/shaped renewable electricity that would qualify for the RPS Adjustment. California EDUs will face compliance obligations for firmed/shaped power imported into California despite the fact that ratepayers paid for zero-emission renewables. Those added costs may be partially offset by an allocation of

allowances to cover the compliance obligations; however, under ARB's current proposal they will not be fully offset because the allocation will decrease over time as the cap adjustment factor reduces the size of every EDU's allocation (in proportion to the reduced emissions cap). By contrast, the number of Cap-and-Trade compliance instruments needed to cover an EDU's firmed/shaped renewable power will increase over time. As indicated in the chart below, category 2 RECs are limited to a specified percentage (generally, 15 percent) of an EDU's RPS compliance obligation, but that RPS obligation grows over time, reaching 33 percent in 2020 and 50 percent in 2030. Therefore, by 2030, up to 7.5 percent of an EDU's generation may come from firmed/shaped renewable energy, but the allowances allocated to cover that generation would be 4.5 percent of the EDU's 2020 expected load times the 2030 cap adjustment factor. That is, by 2030, only a very small fraction of the EDU's load that is associated with zero-emission generation for which compliance instruments may be required will be covered through an allowance allocation.

In order to ensure that California ratepayers are not forced to pay twice for the same zero-emission generation due to California's overlapping regulatory obligations, ARB should retain the RPS Adjustment, modified as outlined above, for the post-2020 period.



(LADWP)

Comment:

ARB Staff proposes to discontinue the RPS adjustment after 2020 and replace it with allowance allocations for each electricity distribution utility (EDU). ARB indicates that the regulation was extremely difficult to track and enforce, stating that:

“in part because to avoid double counting the Regulation could only allow RPS adjustments to be taken in cases in which the electricity associated with the RECs was

not directly delivered to California. It can be difficult for entities to know if the electricity was directly delivered, and there was also widespread misuse of the direct delivery requirement because of misinterpretations of the Regulation (e.g., that one could choose not to specify a source of imported electricity and then use the RECs associated with that electricity for an RPS adjustment). Further, when there are multiple purchasers of electricity and RECs from renewable resource, it is difficult to determine which RECs are associated with which electricity.

ARB Staff “proposes to modify the Regulation to provide each electrical distribution utility (EDU) with an allowance allocation that accounts for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California, and eliminate the RPS adjustment from the Regulation.” While the ARB staff proposal may alleviate reporting and verification difficulties and the double counting of zero emission electricity, it is not clear how the proposed allowance allocation for each EDU would resolve the current disparity between the RPS goals and Cap-and-Trade accounting rules. More importantly, it is not clear how this approach will impact ratepayers in terms of compliance costs associated with meeting the RPS goals and complying with Cap and Trade rules.

ORA recommends that ARB and the CPUC coordinate to assess the full impacts of the proposed methodology on ratepayers prior to discontinuing the RPS adjustment. This coordination could be met through a joint agency workshop to identify the issues and possible remedies. Potential drawbacks from discontinuing the RPS adjustment might result in higher compliance costs passed onto ratepayers, increased difficulty of achieving RPS goals, and increased emission leakage through imports.
(OFFICERATEPAYERADVCT)

Comment:

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...

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. (PG&E)

Comment:

The RPS Adjustment is an Important and Necessary Tool that is Properly Recognized in the Context of the Cap-and-Trade Program

The State's Renewable Portfolio Standard (RPS) Program is a critically important tool in meeting the state's emissions reduction objectives, and as part of meeting the requirements of the RPS mandate, California's EDUs have made considerable investments in renewable energy resources to serve their customers. Indeed, the 2008 Scoping Plan lists achieving a 33% renewable energy mix statewide as one of the "key elements of California's recommends for reducing its greenhouse gas emission to 1990

levels by 2020.”³³¹ Both the Cap-and-Trade program and the State’s RPS program serve the same underlying purpose – to reduce the state’s overall GHG emissions profile. Regardless of whether they do so as a cap on actual emissions or a requirement to utilize lower emitting electricity resources, the end result is the same. Because of this common objective and shared role in helping the state meet its clean energy goals, it is imperative that the value of both programs be fully recognized and integrated for the benefit of the State’s electricity customers. The Cap-and-Trade Program RPS Adjustment provides a means by which to ensure that the value of those investments is not diminished by attaching a GHG compliance obligation to zero-GHG resources. The loss of the RPS Adjustment will cost NCPA member utilities millions of dollars in additional compliance costs. The RPS Adjustment ensures that the compliance obligation of the affected EDU is not overstated by requiring deliveries of RPS-eligible resources to be counted as part of the compliance obligation. This concept has long been recognized by CARB, and articulated in the 2011 Mandatory Reporting Regulation Rulemaking when staff noted that while “RECs play no role in GHG accounting...

RPS electricity should reduce the compliance obligation of a first deliverer.”³³² The RPS Adjustment should be retained as an essential tool to ensure that electricity customers do not incur GHG compliance costs for renewable energy imports.

The RPS Adjustment is also an important cost-containment measure that helps to ensure that California’s electricity ratepayers are not penalized for investments in renewable energy resources located outside of the state. It is an essential instrument in managing Cap-and-Trade Program compliance costs that ensures electricity customers do not pay GHG costs for energy associated with zero-emission, renewable energy resources. NCPA asks that the Board direct staff to revise the Proposed Amendments to ensure that the RPS Adjustment remains in the Program beyond 2020. Eliminating the RPS Adjustment would impede compliance entities’ ability to comply with the RPS Program without incurring added costs. It would also disrupt business practices in the electricity sector, as many commercial arrangements for renewable energy purchases are based on the utilization of the RPS Adjustment for their commercial viability; eliminating the RPS Adjustment will thus result in even greater disruption and costs for those entities. NCPA is concerned that the value and importance of the RPS Adjustment is marginalized by the perception that it is an “optional” measure, rather than an essential part of the Program. The fact that the RPS Adjustment is an optional measure makes it no less important to the compliance entity utilizing it. It is a valuable tool that helps to bridge the gap between two critically important components of California’s climate plan, and does so while ensuring that compliance entities that have made significant investments in clean energy resources are not forced to pay twice for the environmental benefits. This is critically important as those compliance entities,

³³¹ Climate Change Scoping Plan, December 2008, pp. 16-17, see also p. 44.

³³² MRR Amendments, Final Statement of Reasons, October 28, 2011, p. 107

such as NCPA's member agencies, will be subject not only to increasing RPS mandates, but also a tightened GHG emissions cap and increasingly scarce allowances. The RPS Adjustment sends signals that the Cap-and-Trade Program and the RPS Program can work in concert – rather than against each other...

For all of these reasons, and as set forth in the Joint Utility Group comments, given the importance of the RPS Adjustment and the proper accounting for RECs under both the RPS and Cap-and-Trade programs, NCPA asks that the Board direct CARB Staff to pursue proposed amendments to the MRR and Cap-and-Trade Program Regulation consistent with the recommendations set forth herein. NCPA looks forward to continuing to work with CARB Staff and other interested stakeholders in ensuring that continued utilization of the RPS Adjustment provides the intended benefits without placing an undue burden on either CARB or utility personnel. (NCPA)

Comment:

The 2008 Scoping Plan included the RPS program as a recommended complementary measure, recognizing it is a means by which to “achieve cost-effective emissions reductions while accelerating the necessary transition to the low-carbon economy required to meet the 2050 target.”³³³ In recognition of these complementary roles, the RPS Adjustment should be retained as part of the Cap-and-Trade Program. Since it was first included in the Regulation, the RPS Adjustment has served the important function of ensuring that the Cap-and-Trade Program does not work *against* the objectives of the RPS Program by recognizing the significant investments utilities have made in renewable resources, not all of which are located in California. As the utilities have repeatedly noted – in both formal and informal comments to CARB and to Staff – the RPS Adjustment serves an important function in both ensuring that the value of out-of-state renewable energy resources are fully realized by the California electricity customers whose utilities made the investments while also recognizing the overlapping policy objectives of two important but separate programs aimed at meeting California's climate change goals. M-S-R opposes Staff's proposal to eliminate the RPS Adjustment after 2020.

Eliminating the RPS Adjustment has Significant Adverse Cost Implications for Compliance Entities: The importance of the RPS Adjustment should not be marginalized by simply because utilizing the provision is “optional”; it is a critically important measure for avoiding paying additional and unwarranted costs for clean energy imports, as well as ensuring that the GHG emissions profile of the EDUs that have invested in those resources accurately reflects those investments. M-S-R's members have existing resource commitments for RPS-eligible resources located outside of the state that are “firmed and shaped” before serving California load. Those resources account for as much as 35% of the City of Santa Clara's RPS compliance obligation and as much as 85% of Redding Electric Utility's (REU) total renewable

³³³ Climate Change Scoping Plan, December 2008, pp. 19, see also p. 44.

portfolio. For REU along, the value of the RPS Adjustment post-2020 is estimated at over \$600,000 based on conservative price estimates. For the members of M-S-R that have significant investments in these out-of-state renewable contracts, the RPS Adjustment is not deemed an option.

Furthermore, while M-S-R appreciates staff's explicit acknowledgement of the interaction between the Program and renewable energy imports, Staff's proposal to address these impacts through the allocation of allowances directly to EDUs to cover the emissions associated with these imports does not alleviate the cost impact, as these transactions were never intended to be treated as ones that involved a compliance obligation...

Total Emissions for Affected EDUs are Overstated without the RPS Adjustment. The RPS Adjustment correctly adjusts the Cap-and-Trade compliance obligations so that imports of clean, zero-GHG resources used for RPS program compliance are not assigned a compliance obligation under the Cap-and-Trade Program. This does alter or otherwise impact the emissions reported under the MRR. As such, while use of the RPS Adjustment does not affect the accuracy of CARB's GHG inventory report, elimination of the RPS Adjustment does overstate GHG emissions that are assigned a compliance obligation for entities that must now treat their RPS-eligible resource as one with a GHG emission. Therefore, the total GHG emissions attributed to compliance entities with claims to the renewable attributes that were unable to claim the RPS Adjustment reflect a GHG intensity that is greater than their actual emissions, thus skewing both the GHG profile of the compliance entity and needlessly increasing their compliance obligation under the Program. (M-S-R)

Comment:

Redding Electric Utility (REU) is a publicly owned utility that serves approximately 44,000 customers. REU is a covered entity under the Regulation and is subject to an additional California energy policy program, the Renewable Portfolio Standard (RPS) Program that requires electric utilities to procure 50% of their electricity from renewables by the year 2030.

In 2006, REU signed a 20-year contract through the M-S-R Public Power Agency to purchase energy from the Big Horn wind project located in the state of Washington. The wind energy is firmed and shaped in the Pacific Northwest before being delivered to Redding. The firming and shaping takes care of the intermittency of the wind and efficiently utilizes the high voltage transmission grid. This resource accounts for as much as 85 percent REU's total renewable portfolio.

REU supports the comments submitted by the Northern California Power Agency (NCPA), the Modesto-Santa Clara-Redding (M-S-R) Public Power Agency, and the Joint Utility Group (JUG). The following comments are intended to emphasize REU's concern regarding the proposed elimination of the RPS Adjustment after 2020.

Removing the RPS Adjustment as allowed in section 95852(b)(4) of the Regulation would have an estimated cost impact of over \$600,000 per year to REU's customers. This critically restricts REU's ability to procure additional renewable resources in order to meet the increased 50 percent renewable goal. While ARB Staff is proposing the Cap-and-Trade Regulation be modified to provide an allowance allocation in-lieu of the RPS adjustment, it appears that the RPS volume would not be fully recognized with this proposal, resulting in only partial cost offset for REU's renewable investment. By proposing to treat REU's RPS-eligible resources as having a greenhouse gas (GHG) emission, REU's compliance obligation under the cap-and-trade program would reflect approximately 36,000 metric tons of CO₂e annually that is actually associated with RPS-eligible, zero-GHG resources.

REU urges CARB to retain the RPS adjustment in the Cap-and-Trade regulation and work with affected utilities on potential amendments that could ensure consistency among programs and provide greater clarity on utilization of the RPS Adjustment. Doing so, would allow utilities recognition of renewable investments while also ensuring the integrity of the Cap and-Trade program. (REDDING)

Comment:

The Community Choice Aggregators (CCAs) urge the ARB to leave in place the existing RPS (Renewables Portfolio Standard) Adjustment, as well as the existing allowance allocation methodology. Eliminating the RPS Adjustment would reduce competition in the electricity market, create economic hardship for CCAs and potentially slow renewable energy resource utilization amongst California's CCAs...

Background on CCAs

CCAs are local government entities created by statute for purposes of providing customers with expanded choice within the retail electricity sector. Following the implementation of a CCA, customers have the ability to choose amongst multiple service providers and enjoy the prospect of expanded retail electricity offerings, including green energy options that were not available prior to CCA implementation. In areas served by CCAs, the provision of electric service is shared between the CCA and the incumbent investor-Owned Utility (IOU). The CCA provides electric generation services, while the IOU continues to provide delivery, transmission, and billing services. Customers within the CCA's service territory may opt out of the aggregation program at any time, remaining with the incumbent investor-owned utility as "bundled" customers. When evaluating the prospect of CCA or traditional utility service, customers often consider key service attributes, such as renewable energy content, prospective Greenhouse Gas (GHG) emissions impacts, rate competitiveness and stability, as well as the possibility for direct participation in the CCA's ongoing planning and decision making process. To the extent that legislation and/or related regulations adversely impact the CCA's ability to compete with regard to these attributes, the CCA and its customers may be disadvantaged.

There are currently four operational CCAs in California:

- CleanPowerSF, serving the City and County of San Francisco since May 2016.
- Lancaster Choice Energy, serving the City of Lancaster since May 2015.
- Marin Clean Energy (MCE) began serving customers in Marin County in 2010. In 2012, the City of Richmond joined MCE. Unincorporated Napa County and the cities of San Pablo, El Cerrito, and Benicia joined MCE's service area in 2015. In September 2016, MCE started to provide generation service to the cities and towns of Napa County, and the cities of Lafayette and Walnut Creek.
- Sonoma Clean Power (SCP), serving the County of Sonoma since May 2014.

Three additional CCAs are scheduled to begin serving customers soon, including:

- Peninsula Clean Energy in San Mateo County. PCE will begin its first phase of customer enrollment in October 2016, and the second phase will start in April 2017.
- Silicon Valley Clean Energy (SVCE) in Santa Clara County. Customers can expect to receive energy services from SVCE in April 2017. SVCE does not provide services to customers in the cities of Palo Alto and Santa Clara, as those cities have established municipal utilities.
- Apple Valley Choice Energy (AVCE) in the Town of Apple Valley. AVCE plans to commence customer service in April 2017 via a single-phase implementation process.

To date, all operating CCAs have adopted similar missions focused on service reliability, cost-competitiveness, local economic development, and environmental responsibility. Because of these similar goals and objectives, existing CCAs in California tend to invest more heavily in renewable resources than their IOU counterparts, resulting in supply portfolios that exceed prescribed RPS procurement mandates.³³⁴ Many CCAs have also adopted future RPS goals that far exceed the new standard set by SB 350. For example, in its most recent Integrated Resource Plan (IRP), MCE's Board of Directors adopted the goal to have an 80% RPS-eligible and 95% GHG-free supply portfolio by 2025.³³⁵ Sonoma Clean Power has committed to reaching a 50% RPS-eligible portfolio in 2020, ten years ahead of the State's requirement. To achieve these noteworthy clean energy procurement objectives, it is imperative that CCAs retain

³³⁴ CCAs typically offer a default electricity product, and a 100% renewable product. Currently, 35% of CleanPowerSF's default product is sourced from renewable generation, so is LCE's default product. SCP's default product contains 36% renewable sources, and MCE offers a 52% renewable default product.

³³⁵ Marin Clean Energy—Integrated Resource Plan: 2015 Update at page 8 and 22.

access to cost-effective renewable energy products within California and throughout the Western United States.

Eliminating the RPS Adjustment Would Impede the CCAs' Ability to Provide Competitively Priced Renewable Energy, and Is Inconsistent with State Policy

Because CCA customers can return to IOU service at any time, it is essential that these organizations prudently manage procurement and price risks to avoid imposing excessive costs on the customers of the CCA program. To the extent that CCA rates materially increase relative to similar rates charged by the incumbent IOU, it is reasonable to assume that customers may elect to opt out of the CCA program. This leaves the CCA with renewable energy purchase commitments that do not decrease with its declining customer base. This can significantly harm early-stage CCAs operations, who have yet to establish financial stability, meaningful financial reserves and/or credit ratings to support ongoing procurement activities at the lowest possible cost. During this period of time, procurement of lower-cost renewable energy options, including PCC-2 products, is an important element of each CCA's resource planning process. Such products are typically procured under shorter-term contracts with prices that are well below available PCC-1 options. This practice promotes cost competitiveness and regulatory compliance with California's RPS program, which allows the use of PCC-2 products for a portion of each retail seller's procurement obligation. The comparative relationship of PCC-1 and PCC-2 prices is substantially dependent upon the RPS Adjustment offsetting carbon costs that would otherwise apply to such transactions.

Unlike the IOUs, CCAs do not have guaranteed cost recovery for commodity costs. The IOUs' commodity costs are evaluated and adjusted through the annual Energy Resource Recovery Account (ERRA) proceeding, overseen by the California Public Utilities Commission (CPUC). As a result, the IOUs' commodity costs and electricity revenues are "decoupled." However, these commodity costs and electricity revenues are not decoupled for CCAs. To ensure that the CCAs can offer competitively priced energy products, CCAs must balance the costs of resource procurement against their electricity sales. Therefore, the RPS Adjustment is especially crucial for emerging CCAs to provide competitive rates before they have the financial ability to procure more directly delivered RPS resources.

If the RPS Adjustment is eliminated, PCC-2 firming and shaping transactions will be far less cost-effective when compared to directly delivered RPS imports (PCC-1). By denying the RPS Adjustment to entities which have purchased environmental attributes from out-of-state, RPS-eligible generators as a component of each PCC-2 transaction, the ARB would have the effect of substantially increasing procurement costs for CCAs and other wholesale renewable energy buyers within California, which may result in CCAs needing to defer planned renewable energy procurement due to budgetary and rate-related impacts. Needless to write, impeding mandatory or voluntary renewable

energy purchases seems to conflict with California's prevailing environmental policy objectives.

Furthermore, by eliminating the RPS Adjustment, the ARB may impede the general development of CCAs in California. In addition to the operating and emerging CCAs, approximately 20 jurisdictions are currently exploring either forming their own CCAs or joining existing CCAs.³³⁶ Pacific Gas and Electric Company (PG&E) has estimated that 50% of its current load will depart for CCAs in the future.³³⁷ The growth of CCAs is possible because existing regulations provide such entities with the flexibility to choose from different types of renewable products, each of which has different cost structures, economic development benefits and communication implications amongst other considerations. Thus far, CCAs have been able to provide customers with cleaner electricity than their IOU counterparts while still offering comparable rates. The use of PCC-2 resources does not remove a CCA's obligation to match load and supply resources. CCAs are exposed to the same imbalance costs and must procure sufficient resource adequacy in the same manner as EDUs. (JOINTCCAS)

Comment:

SDG&E urges the Board to continue the RPS Adjustment as it was intended to be used by the Board... (SDGE)

Comment:

On the topic of the RPS adjustment, I'm not going to repeat all of what Ms. Sutley expressed concerns about, you know, the removal of the RPS adjustment. We're also concerned about that. What I wanted to point out was how this would affect Turlock in particular. We made an early investment in RPS resource, an out of state wind farm that's 136 megawatts. We did that before there was any requirement to do so.

And we rely on the RPS adjustment to ensure that we can get that power to our ratepayer owners at, you know, a basically a zero carbon cost. Removing the RPS adjustment would result in a considerable cost to us. It would be on the order of a million dollars a year. And that's based on current allowance prices.

You have 2 proposals basically before you right now. One is to retain the RPS adjustment. The other one is to deal with -- remove the RPS adjustment and replace it with an allowance allocation. And the problem with the latter is that it will make PCC2, or Procurement Content Category 2, imports much less cost effective going forward.

And it won't address the fact that companies like Turlock Irrigation District made substantial early investments in out-of-state resources, and rely on that to basically

³³⁶ California Community Choice: An Interactive Map, Clean Power Exchange.
<http://cleanpowerexchange.org/california-community-choice/>

³³⁷ PG&E Notice of Ex Parte Communication at the CPUC, Application 14-05-024. Notice filed on August 29, 2016.

meet more than the minimum PCC2 requirements. They use it for all their RPS obligation.

So we would urge you to not remove the RPS adjustment, and we look forward to continuing to work with staff towards a resolution of this issue. (TURLOCKID2)

Comment:

MID strongly opposes amendments that would increase the difficulty of claiming RPS adjustments from 2018-2020 and discontinue the RPS adjustment post-2020. The RPS adjustment is an essential provision of the Cap-and-Trade and MRR regulations. The adjustment recognizes the zero-emission attributes of energy resources that EDUs procured prior to the inception of the program. Ratepayers invested in these resources to comply with the environmental goals of the RPS and should also receive the zero-emissions benefit inherent to these facilities in the Cap-and-Trade program. (MODESTOID)

Comment:

Importance of Retaining the “RPS Adjustment”

SCPPA – along with numerous other stakeholders, including other publicly-owned utilities, investor-owned utilities, community choice aggregators, renewable developers, and renewable trade associations – continues to strongly believe that the Renewables Portfolio Standard (RPS) Adjustment must be retained in the Regulation in order to complement implementation of California’s expanding and more aggressive RPS Program. These stakeholders have repeatedly expressed the importance of avoiding regulatory changes that would undermine the RPS Program, which is achieving the bulk of the state’s emissions reductions to date. Indeed, for nearly a year, there have been dozens of oral and written comments submitted, meetings and discussions held with ARB staff and managers, and multiple iterations of industry proposals and background information offered to relay the importance of retaining and consistently implementing the RPS Adjustment. This programmatic feature is a critical component to ensuring that successful and cost-effective RPS implementation is continued, as it safeguards against any prejudice between in-state and out-of-state renewable resource procurement. Eliminating the RPS Adjustment will create sector-wide ramifications that would detrimentally impact current and future RPS goals, investment in renewable generating resources, and electricity markets. California surely could not intend such a negative consequence to its climate policies.

The RPS Adjustment is important to offset the Cap-and-Trade compliance cost for imported renewable energy that is not directly delivered to California. Eliminating the RPS Adjustment credit would impose significant annual compliance costs on California electric utilities and consumers. These costs will run in the tens of millions of dollars annually and it seems these costs have not been incorporated into any ARB economic models to date.

Imported renewable electricity is essential for many California utilities to achieve California's increasing RPS target, and will continue to be essential as the RPS requirement increases from 33% in 2020 to 50% by 2030. The RPS and the Capand-Trade Regulation are key regulations in the State's efforts to dramatically reduce statewide GHG emissions. These programs should complement one another, and one program must not reduce the effectiveness of the other. Out-of-state renewables are an important means of achieving the State's renewable energy goals, especially with the anticipated implementation of the federal Clean Power Plan, potential expansion of the California Independent System Operator (CAISO) Energy Imbalance Market (EIM) and grid regionalization efforts, and increasing land-use restrictions that inhibit the ability to build large-scale renewable projects in California. The RPS Adjustment acts to ensure fair treatment of RPS compliant contracts and investments. As was recognized by ARB Chairman Mary Nichols during the recent June 23, 2016 Board Meeting on the 2030 Scoping Plan where she stated "We are implementing a number of very big, costly, important regulations as part of our existing climate program, of which the Cap-and-Trade Program is certainly one, and an important one, but not the only one....The Renewable Portfolio Standard, we were lapped...we started out with a certain number, and now we're coming up with a more ambitious number, layered on top of a Cap-and-Trade Program, so that they -- our electric generating sector is subject to multiple different requirements, and yet [the RPS] program is also operating in a way that's pushing change..."

SCPPA appreciates the Chairman's recognition that the electric sector is subject to multiple requirements, and further stresses the need for the myriad of state policies to work together. We urge ARB to work alongside stakeholders towards reconciling contradictory policy and program implementation concerns – such as the proposed elimination of the RPS Adjustment – that are collectively hampering efforts to get us to where we, as a state, are headed with climate and energy policies. (SCPPA)

Comment:

As highlighted by some of the other speakers today, we ask that the ARB continue the RPS adjustment. The RPS Adjustment is essential to the long-term success of the Cap-and-Trade Program, and furthers California's environmental policy goals by keeping renewables affordable in California.

Continuing the RPS adjustment will provide much needed regulatory certainty that will guide investments and utility planning efforts. Removing the RPS adjustment may result in unintended impacts to imported renewable electricity, and the RPS. And the ARB should ensure the Cap-and-Trade Program and the RPS continue to work in tandem. (CALMUNIUTILASSOC)

Comment:

Similar to concerns raised by others, SCPPA does not support the proposal to remove the RPS adjustment from the Cap-and-Trade Program. We feel that this change would

be fundamentally inconsistent with some of the existing State policies, and ongoing efforts by the Governor's office to regionalize the market.

Imported renewables are going to be critical to meet the increasing RPS targets, and particularly, given land-use constraints that limit our ability to develop in-State large renewable projects. So removing the RPS adjustment would really increase the cost of compliance with that program.

We have been working with the joint utility group on this issue, and we've developed a proposal there. We support the comments from Ms. Sutley earlier with LADWP to essentially work with staff to evaluate these alternative proposals. (SCCPA2)

Comment:

MID, as others, similarly do not support the elimination of the RPS adjustment for the 2021-2030 time period. MID's contracts that are currently eligible for the RPS adjustment are 45 percent of MID's 2020 33 percent RPS requirement.

The anticipated impact to MID customers and MID over that period, the entire period, for elimination of that adjustment as proposed would be -- you know, with the concepts proposed on the table are \$31 million over that period.

Approximately 12,000 of MID's roughly 115,000 customer accounts qualify for rate assistance. And in Modesto, all except for one small community, qualifies as a disadvantaged community. So the concern of the elimination of the RPS adjustment and financial impacts are important to MID. (MODESTO2)

Comment:

Redding supports the comments submitted by NCPA, MSR and the JUG. At this time, I'd like to emphasize our concern regarding the proposed elimination of the RPS adjustment.

In 2006, as an early adopter, Redding contract for wind energy from the Pacific northwest that is firmed and shaped before being delivered to Redding. And this resource accounts for approximately 85 percent of our RPS.

Eliminating the RPS adjustment would cost our customers over \$600,000 per year or a one -- I'm sorry, a half percent rate increase. And this would critically restrict our ability to procure new renewable resources to meet California's 2030 renewable and greenhouse gas goals.

So we urge you to retain the RPS adjustment in the Cap-and-Trade Regulation, and direct staff to please work with affected utilities on amendments that can ensure consistency among California RPS and greenhouse programs. (REDDING2)

Comment:

We are in support of the comments submitted by the Joint Utility Group, MSR, and the CPA.

There's been a lot of talk today about cost burden, cost containment. And one thing about the RPS adjustment, or the removal of it, or even the adjustment of it to offsets, it's not optional for us. They say it's voluntary. It's not. It really has cost implications. I just looked at the 2014-2015 RPS -- I mean, MMR reporting and tried to extrapolate that. What would that cost be if I could not count that as renewable or as carbon free. It would be about a million dollars a year.

Now, this is a contract we entered in early ahead of the game. We still have 10, 15 years left on this contract. That would translate to a 3 to 5 percent rate increase over the next 10 years for our -- and this is just RPS adjustment alone.

Then I started looking at the opportunity costs. We pay a premium for this energy. We pay a lot of money just for that little bit that would be not considered adjustable, or greenhouse gas free. We paid about \$9 million in 2015 for that.

If I would have bought it on the market as an unspecified, I would have paid 4 million for it. And that cost difference is huge for our customers. That's an opportunity to cost, and I'm not including like RPS cost on top of that.

So it really can have impacts of what we could have done with our money and what we could go -- do going forward. Another -- you know, it's one thing that comes to mind is when you say it was optional, we have -- you know, on our house we can take off our interest. That's optional, but most of us take that off of our long-term thing. So to us, again, it's not optional.

We also have a lot of confusion among our ratepayers. We very large industrial commercial customers that are saying what's our carbon intensity. They can't go by what CARB is, especially if you take out renewables that is supposed to be greenhouse gas free. We also have others that sit -- do the greenhouse gas protocol, and they can't go by CARB's numbers, because that doesn't adhere to the Kyoto Protocol and everything else going forward with that kind of reporting.

We have the power content label. We have the RPS. And they're all different in how we have to explain this and this message to our customers.

So it would be nice to see some conformity between the State of California and what kind of message we can send to our customers and have that addressed as well.
(SILICONVALLEYPOWER)

Comment:

And with regards to the RPS adjustment, there -- staff provided a couple of options. But the problem with staff's options was that they don't fix the problem. And the problem is

the additional cost to the ratepayers. So in the original allocation, it was assumed that all RPS-eligible electricity was zero emission. So the RPS adjustment was supposed to cover the portion for which you have to report emissions. So it is not optional. So I just wanted to clarify that. (LADWP3)

Comment:

....the Final Statement of Reasons for one of the MRRs stated that there should not be a compliance obligation under the Cap-and-Trade Program for RPS-eligible resources. And retaining the RPS adjustment ensures that that carries through. (NCPA2)

Comment:

I'd like to note that we've been an early adopter, and we don't want to get punished for that. And not to cross the Board Chair, all I'm going to say is RPS adjustment, and I'm going to leave it at that. [For context, prior to this comment at the Board Hearing, Chair Nichols said "... I don't know if there's anybody left speaking for electric utilities, but we can all just assume you don't like the RPS adjustment."] (TURLOCKID3)

Comment:

On behalf of Sonoma Clean Power, MCE Clean Energy, Peninsula Clean Energy, Silicon Valley Clean Energy, and Lancaster Choice Energy, we support the continuation of the RPS adjustment as currently implemented, as well as the existing allowance allocation, and the Cap-and-Trade program and mandatory reporting rules.

Community Choice Aggregators are local government entities created by statute for the purpose of providing customers expanded choice within the retail electricity sectors. When CCA's form, customers consider service attributes, such as the percentage of renewable energy content and the greenhouse gas emissions impact. Many CCAs have adopted RPS goals that far exceed the standards set by SB 350.

For example, in the most recent integrated resource plan, MCE's board of directors adopted the goal to have an 80 percent RPS-eligible and 95 percent GHG-free portfolio by 2025. Sonoma Clean Power has committed to reaching 50 percent RPS eligible portfolio by 2020. That's 10 years ahead of the State's requirement.

In order to achieve this noteworthy clean energy procurement objectives, it is imperative that CCAs retain access to cost-effective renewable energy products within California and throughout the western United States.

Eliminating the RPS adjustment could make the ability to supplies renewable, energy to our customers cost prohibitive. I'm not going to go into all the reasons of why that is and how that would directly impact our business, as I think we've heard that from many others.

CCAs also oppose the proposal to replace the RPS adjustment by allocating allowances to EDUs. Although, this credit would be allotted to the ratepayers, this allocation does

not go directly to the CCA or allow us to use it to meet compliance obligations. Thus, this alternative mechanism excludes CCAs. And we've invested heavily in renewable resources as a major component of our portfolio, and as an unintended consequence CCAs would suffer a competitive disadvantage.

Given that CCAs continue to grow in the State of California, and given that the strides that we have made in reducing GHG emissions, we ask the Board not to accept these proposed changes, and to hinder our future progress for a cleaner California.
(SONOMACLEAN)

Comment:

The Staff proposal treats EDUs and other first deliverers differently with respect to a “credit” for imports of “PCC 2” energy or other renewable energy that cannot be delivered to California in real-time due to transmission or other constraints. If this differential treatment is adopted, retail sales customers of non-EDU load-serving entities (“LSE”) will be subject to additional GHG compliance costs beyond the costs borne by EDUs’ retail sales customers. For this reason, the RPS adjustment should be retained for all first deliverers of electricity, subject to a potentially revised calculation of the RPS adjustment. If the ARB is insistent upon eliminating the RPS adjustment, the allocation of additional allowances (if any) must apply equally to all importers of out-of-state electricity, and the process must be transparent.

Rather than establish a discriminatory allowance allocation protocol that disadvantages retail customers of non-EDU LSEs, the ARB should retain the RPS adjustment, but with a modified calculation of the RPS adjustment after 2020. Alternatively, if the RPS adjustment is to be eliminated, and if additional allowances are to be allocated, the ARB should allocate the additional allowances on a proportionate basis to all first deliverers of electricity.

BACKGROUND

The current RPS adjustment (Article 5, Section 95852(b)(4)) recognizes “the compliance obligation incurred by electricity importers when procured RPS-eligible renewable generation, that is not directly delivered to California, is replaced by higher emitting electricity generation.” Initial Statement of Reasons (ISOR) at p.53. The ISOR notes that “[t]his RPS adjustment is voluntary, and it is only applicable when the importer purchases both electricity and renewable energy credits (REC) together and can demonstrate that the electricity was not delivered to California.” Id.

The RPS adjustment applies to the importation of out-of-state RPS-eligible generation that qualifies under P.U. Code Section 399.16(b)(2), which is one of three categories of compliant RPS products under California’s RPS procurement requirement. In accordance with P.U. Code Section 399.16(c)(1), during the RPS compliance period beginning in 2021, an LSE may include any percentage up to 25 percent of its RPS procurement quantities under P.U. Code Section 399.16(b)(2) (PCC 2). This means that

each LSE's percentage of PCC 2 quantities is different, based on the LSE's contracting practices and its RPS portfolio construction. RECs associated with an LSE's PCC 2 procurement are verified by the Energy Commission.

Under current rules, the RPS adjustment is available to all first deliverers of electricity. The RPS adjustment reduces a first deliverer's GHG compliance costs that are passed through to the first deliverer's wholesale and retail sales customers. The cost savings associated with the RPS adjustment benefit all retail customers, because all retail customers pay a premium for the renewable attributes of the generated energy, commensurate with the LSE's reliance upon PCC 2 procurement in its RPS portfolio. The RPS adjustment is effective in compensating all first deliverers of electricity (and their ultimate customers) for the GHG compliance obligation incurred by electricity importers for PCC 2 energy or other renewable energy that cannot be delivered to California in real-time.

THE STAFF'S PROPOSAL TO DISCONTINUE THE RPS ADJUSTMENT AFTER 2020

The Staff proposes to discontinue the RPS adjustment after 2020. The ISOR states that the RPS adjustment has been "extremely difficult to track and enforce, in part because to avoid double counting the Regulation could only allow RPS adjustments to be taken in cases in which the electricity associated with the RECs was not directly delivered to California." ISOR at p. 53.

Discontinuance of the RPS adjustment after 2020 eliminates a cost mitigation measure for all first deliverers of electricity that import renewable energy that cannot be delivered to California on a real-time basis, including PCC 2 products. Recognizing the Staff's concern regarding verification of direct deliveries of imported energy quantities to California, there are less drastic ways to ensure that the RPS adjustment is applied exclusively to a first deliverer's PCC 2 quantities (or other renewable energy that cannot be delivered to California in real-time). As noted above, the Energy Commission verifies the eligibility of all PCC 2 quantities claimed by LSEs in California. The RPS adjustment can and should be matched against the PCC 2 quantities verified by the Energy Commission.

To the extent the ARB wishes to reflect that non-renewable energy is imported into California, the RPS adjustment calculation can be modified to reflect an emission rate that is lower than the default emission factor for unspecified sources. However, the emission factor should be sufficient to reflect ratepayers' investment, and that "but for" the PCC 2 procurement, the renewable energy production would not have displaced other generation.

If the RPS adjustment is to be eliminated, any allocation of additional allowances intended to mitigate the cost impact should be undertaken in a transparent and even-handed manner. Unfortunately, the Staff's proposal to replace the RPS adjustment with an allocation of additional allowances exclusively to EDUs is neither transparent nor even-handed. After 2020, the Staff proposes to "modify the Regulation to provide each

EDU with an allowance allocation that accounts for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California” ISOR at p. 53. The ISOR states that “[t]his allowance allocation will serve the same purpose as the original RPS adjustment, but will alleviate the reporting and verification difficulties and the potential for double counting of zero emissions electricity.” Id. Contrary to the Staff’s assertion, the allocation of additional allowances exclusively to EDUs will not serve the same purpose as the RPS adjustment.

THE STAFF’S PROPOSAL RESULTS IN DIFFERENTIAL TREATMENT OF FIRST DELIVERERS OF IMPORTED ELECTRICITY

The allocation of additional allowances exclusively to the EDUs under the Staff’s proposal -- to account for renewable electricity that is not delivered to California in real-time -- presents the potential to disadvantage non-EDU first deliverers of imported energy, as well as non-EDU LSEs and their retail customers. If the ARB allocates an additional quantity of allowances to the EDUs, but does not allocate additional allowances to non-EDU importers of PCC 2 quantities on a proportionate basis, the potential exists for retail customers of non-EDU LSEs to bear a disproportionate burden for the GHG compliance costs associated with the importation of PCC 2 energy.

An LSE that is a first deliverer (or that procures PCC 2 quantities from a first deliverer) may not be able to recover the GHG compliance costs associated with those PCC quantities from its retail customers. The reason is that these non-EDU retail customers may receive an allocation of additional allowance revenues from the EDU that is not in proportion to the percentage of PCC 2 quantities in its LSE’s RPS portfolio. As noted above, a non-EDU LSE is likely to include a different percentage of PCC 2 quantities in its RPS portfolio than the percentage of PCC 2 quantities in an EDU’s RPS portfolio. If an EDU’s percentage of PCC 2 quantities is different from another LSE’s percentage of PCC 2 quantities, the benefit of the additional allowance allocation to the EDU will be distorted in customer rates, creating a competitive disadvantage for non-EDU LSEs.

Allocating additional allowances exclusively to the EDUs would be unduly discriminatory. Owing to the discriminatory impact of the Staff’s proposed approach, the ARB should retain the RPS adjustment, subject to modification of the calculation. Alternatively, if the RPS adjustment is to be discontinued after 2020, the ARB should work with stakeholders, in the period prior to discontinuance of the RPS adjustment, to develop a means by which to allocate additional allowances to, or otherwise compensate any LSE that can demonstrate importation of verified PCC 2 quantities. (SHELL)

Response: Numerous comments opposed staff’s proposal to remove the RPS Adjustment from the Regulation after 2020 and replace it with allocation to EDUs to cover the cost burden that would have been associated with this change. In response to stakeholder comments, in the first 15-day changes to the Regulation,

staff withdrew the proposed amendment to remove the RPS adjustment, and retained the current RPS Adjustment provisions.

Per the Cap-and-Trade Regulation, electricity imports and electrical distribution utilities are not required to utilize the RPS Adjustment; this is why staff have referred to the fact that the RPS Adjustment provisions of the Regulation are voluntary. An entity may only apply the adjustment when it purchases both electricity and the renewable electricity credits (RECs) together and can demonstrate that the electricity was not directly delivered to California. As has always been the intent of these provisions, the purpose of the RPS Adjustment is to allow for a reduction of the compliance obligation for EDUs or for entities that import electricity on behalf of EDUs. The RPS Adjustment was created to recognize investments in out-of-State renewable resources, and is allowed when RPS-eligible electricity is purchased along with RECs and the electricity is not directly delivered to California. The requirement that the electricity is not directly delivered to California is crucial to ensuring that zero-emission electricity is not double counted in the Cap-and-Trade Program. If the electricity was indeed directly delivered, then it is required under MRR to be reported as from a specified source for facilities or units in which the importer is the generation providing entity or the importer has a written power contract to procure electricity. ARB intends to publish the REC serial numbers for specified source imports and RPS Adjustment claims on the ARB website to ensure transparency.

One utility requested greater clarity on the utilization of the RPS Adjustment. Staff notes that the December 2015 workshop slides included within Appendix F to the ISOR for this rulemaking,³³⁸ contain details on the MWh and reduced compliance obligation associated with RPS Adjustment claims that were in conformance with the Regulation, as well as the reduced compliance obligation associated with RPS Adjustment claims that were not in conformance with the Regulation and therefore not able to be claimed as an RPS Adjustment. These data were from the 2014 data year—the most recent year for which data were available at the time. Due to prohibitions on revealing confidential business information, staff is unable to reveal utility- and importer-level information on utilization of the RPS Adjustment, but is willing and able to discuss with individual utilities and importers how they can claim the RPS Adjustment in conformance with the Regulation.

One commenter stated that the differing calculation methodologies from overlapping programs (e.g., Cap-and-Trade Program, RPS, power content label) make it difficult for utilities to explain their GHG emissions intensities to customers. Staff notes that the California Energy Commission is working with ARB, under direction from Assembly Bill 1110 (Ting, Statutes of 2016), to adopt a

³³⁸ <https://www.arb.ca.gov/cc/capandtrade/meetings/20151214/rpssb350.pdf>; see slide 9.

methodology to calculate the GHG emissions intensity for the electricity supplied by each retail supplier in the State.

Many commenters also requested increased consistency between the RPS and Cap-and-Programs. Staff responds to this request in the response to 45-day comments D-3.2.

Requests to Align RPS Adjustment with the RPS Program

D-3.2. Multiple Comments:

When it designed the Cap-and-Trade Regulation, ARB appropriately recognized that the structure of California's RPS could result in cap-and-trade compliance obligations for zero-emission power that is firmed/shaped prior to delivery. California's RPS program allows a percentage of an EDU's RPS compliance obligation to be satisfied with firmed/shaped renewable electricity. Firmed/shaped renewable electricity is renewable electricity that the EDU pays to be generated but for which it receives substitute electricity which carries a GHG "compliance obligation" as unspecified power.

Consistent with the mandate under AB 32 to work with the CPUC to "minimize duplicative or inconsistent regulatory requirements," ARB addressed this problem by establishing an RPS Adjustment for firmed/shaped renewable energy imported into California. Specifically, the RPS Adjustment reduces EDU Cap-and-Trade compliance obligations for any zero-emission generation that the EDU pays for in order to meet its RPS obligations, but which was not directly imported into California due to transmission constraints or operational reasons. That is, for the purpose of Cap-and-Trade Regulation compliance, the RPS Adjustment treats firmed/shaped renewable energy as zero emission generation, consistent with its treatment under California's RPS.

ARB has recently made or proposed two revisions to the Cap-and-Trade Regulation relating to the RPS Adjustment. As discussed below in greater detail, both of these rule changes will significantly, unnecessarily, and unfairly increase the costs paid by California ratepayers for zero-emission generation, without achieving a corresponding environmental benefit.

Revisions to RPS Adjustment for the 2016-2020 Period

ARB staff recently issued guidance on the use of the RPS Adjustment under the existing Cap-and-Trade Regulation. This new guidance sets a high bar (i.e., burden of proof) that California electric utilities must satisfy in order to claim the RPS Adjustment credit. Under this new guidance, California electric utilities must demonstrate to the verifier that the original electricity produced by the renewable generating facility did not come into California. California electric utilities often do not have access to that proof because e-tags are confidential and to see the e-tag, the California electric utility must be a party listed on the e-tag. If LADWP is dealing with a middleman, LADWP cannot see the e-tags that show where the original electricity sank. In such cases, LADWP (and similarly-situated California utilities) cannot prove that the

original electricity did not come into California and therefore cannot satisfy the burden of proof in order to claim the RPS Adjustment credit. If the California utility cannot claim the RPS Adjustment credit to offset the GHG emissions reported for the imported firmed/shaped RPS-eligible electricity, the utility's customers will end up paying twice: 1) they will have to pay a premium to buy zero emission renewable electricity with all of its environmental attributes in order to satisfy the RPS, and 2) they will also have to pay for Cap-and-Trade compliance obligations for the imported firmed/shaped electricity.

This ARB guidance severely limits the usefulness of the RPS Adjustment and so risks imposing significant additional costs on California ratepayers for zero-emission generation for which they are already paying in order to comply with the RPS mandate. This interpretation will impact EDUs such as LADWP for the next 5 years. ARB should revise its approach to the RPS Adjustment requirements for the 2016-2020 period and continue to apply this corrected approach thereafter during the post-2020 term of the Cap-and-Trade Regulation.

ARB's interpretation of the Mandatory Reporting Rule (MRR) and Cap-and-Trade Regulation has the effect of benefitting power traders that purchase "null" power (which is formerly renewable electricity from which RECs and environmental attributes have been removed) from out-of-state renewable generating facilities and import that electricity into California. Power traders with a portfolio of assets can selectively choose which generation asset that they schedule for delivery into California. Unfortunately, ARB is not enforcing the existing provision of the Cap-and-Trade Regulation that requires an electricity importer to report the associated REC serial numbers in order to claim a compliance obligation for imported electricity based on a specified source emission factor (when RECs are created, which should be for all RPS renewable procurement). By failing to enforce this requirement, ARB is providing power traders a financial incentive to strategically select "null" power from renewable generating facilities for direct delivery into California, thereby increasing their earnings at the expense of California ratepayers. In effect, ARB's interpretation of the MRR and Cap-and-Trade Regulation is providing power traders free GHG emission benefits to which they are not contractually entitled and preventing the California electric utilities that paid for the zero-emission renewable electricity and own the RECs associated with that electricity from claiming the zero-GHG emission benefit under the RPS Adjustment on behalf of its customers. This approach is inconsistent with both the legislative intent of the RPS and AB 32 laws, as well as the past positions that ARB has adopted to establish and implement the Cap-and-Trade Regulation.

With respect to the intent of the California Legislature, Section 399.11(b) 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 GHG reductions-with one benefit described as "displacing fossil fuel consumption in the state" and the other greenhouse gases

associated with electrical generation." benefit described as "meeting the state's climate change goals by reducing emissions of This statutory language makes it clear that the Legislature intended the RPS Program to function as a mechanism to reduce GHG emissions from the electric power sector and thereby achieve the GHG emission reduction goals of AB 32. As a result, ARB has a legal obligation to align the two programs and to do so in a manner that provides full credit for the GHG reductions achieved under the Cap-and-Trade Regulation.

This approach was incorporated into ARB's design of the Cap-and-Trade Regulation. Specifically, ARB established a regulatory scheme that provided electrical distribution utilities with no allowances to cover GHG emissions for imported RPS-eligible firm/structured renewable electricity. No allowances were allocated because it was assumed there would be no corresponding compliance obligation for any renewable energy imported into California. The RPS Adjustment was established to offset those emissions as a deduction to the Cap-and-Trade compliance obligation, effectively treating this imported RPS-eligible electricity as zero-emission power under the Cap-and-Trade Program. By changing the requirements to claim the RPS Adjustment midstream, ARB has effectively "broken" its deal with the California electric utilities to treat all RPS-eligible electricity as zero emission under the Cap-and-Trade Program as was intended when the free allocation was set.

LADWP proposes that ARB provide a supplemental allocation of allowances to cover firm/structured imported renewable electricity that does not qualify for the RPS Adjustment credit because the EDU does not have the adequate documentation to prove the original renewable electricity did not come into California. Because this issue is affecting EDUs now, LADWP requests that ARB implement this fix as soon as possible and not wait until the start of the 2020 compliance period. LADWP will continue to work with the California utilities and ARB to develop language/guidance to prevent misreporting of null power and clarify what entities are entitled to claim the zero emission attributes for imported firm/structured renewable energy. (LADWP)

Comment:

In this -- I wanted to draw your attention to one issue that's very important to us, and that's the treatment of the RPS adjustment in the proposed amendments and in guidance. And the California electric utilities have come together on this issue and we've been in discussions with staff for many months, and we've yet to come to a resolution.

Now, we certainly understand the concern about potential double counting around certain existing out-of-state renewable electricity contracts where there may not be direct delivery into California, but the proposed treatment will have real cost impacts for our ratepayers. In our case, these are contracts that were signed before cap and trade. We acquired the renewable energy credits and they count towards our RPS obligations.

They represent early actions and early investments by Los Angeles, and other utilities are in a similar situation.

In 2011, ARB allocated GHG emission allowances to the electric distribution utilities for the protection of our ratepayers. The formula that was used to set the allowance allocation for all -- for the electric utilities treated all renewable energy, the 33 percent, by 2020 as zero emission.

California ratepayers are paying for renewable energy to be generated and this is reducing greenhouse gas emissions within the western electric grid. The electric utilities received no allowances to cover these GHG emissions for the imported RPS eligible electricity that wasn't directly delivered into California, and the RPS adjustment addressed the associated compliance issues.

So the joint utilities group has proposed 2 solutions. One is to allow the REC owner to claim the RPS adjustment credit for that RPS-eligible electricity that's imported and assign the GHG emissions to the imported null power. And we've already paid for the environmental attributes of those contracts. And the second to provide a supplemental - or to provide a supplemental allocation to the REC owners.

For us, these contracts represent about 4 ½ percent of our retail sales. And if we have to purchase allowances to cover, it would cost our ratepayers an additional a six to seven million dollars a year with no additional environmental benefits. So we'd like you to consider one of those solutions. (LADWP2)

Comment:

SMUD worked for and appreciated the adoption of the RPS Adjustment, and believes strongly that it should be continued in the Cap-and-Trade Program. SMUD believes it is possible to use the RPS Adjustment as intended, and strongly encourages its continuance. We have used the RPS Adjustment in the past to help conform our carbon obligation under the Cap-and-Trade Program with the carbon footprint of our renewable procurement. We think that such conformance is generally good, as nonconformance of these values can lead to confusion on the part of consumers and other stakeholders.

SMUD notes that since the current treatment of RECs and null power was developed in 2010 or so, there have been dramatic changes in the complementary RPS policy in the state. The RPS has been altered from a 20% requirement to procure renewable generation that did not clearly apply to all EDUs in California and that did not clearly allow compliance with unbundled RECs and firmed and shaped contracts from outside California to a 50% requirement that applies clearly to all EDUs in the State and explicitly allows compliance using firmed and shaped contracts with delivered substitute power and with unbundled RECs. SMUD believes that the RPS program remains a "complementary program" that is intended to provide emission reductions from renewable procurement, leaving fewer emissions that must be covered in the Cap-and-

Trade Program. The ARB should make every effort to conform these two important policies as they are modified over time, and it is essential that the dramatic changes in the RPS in California be considered as carbon policy is updated.

Procuring renewable power by definition involves procuring a zero-GHG (or low-GHG) resource. There are many instances where a Cap-and-Trade carbon obligation is not reduced by this zero-emission procurement – where there is a mismatch between the underlying GHG emissions of the resource procured by the utility and the procurer's Cap-and-Trade carbon obligation. The RPS Adjustment was a fix for one of these types of mismatches – where a utility bought bundled renewable power outside the state, but the power could not be delivered to the state, and substitute emitting power was delivered in its stead. Again, SMUD supports continuing to include fixes such as the RPS Adjustment in Cap-and-Trade.

SMUD suggests then that ARB take the opportunity presented by the current questions about the RPS Adjustment and 'direct delivery' to revise the Cap-and-Trade structure to be more consistent with the RPS program and standard understandings of RECs in California, rather than remove the RPS Adjustment as proposed. SMUD believes that the zero or near-zero GHG attribute of eligible renewable generation can be associated clearly with the ownership of RECs in more instances in the Cap-and-Trade structure, and that this action would serve to conform the RPS program and Cap-and-Trade to a significantly greater degree and to reduce market confusion about an entity's carbon obligation in comparison to its carbon footprint. SMUD believes that conformance between Cap-and-Trade and the RPS program should be pursued in all cases where it can be established without harming the integrity of either program.

The RPS Adjustment allows the Cap-and-Trade structure to recognize the zero-emission nature of the renewable procurement when it occurs in an uncapped jurisdiction. There is the potential for double counting of emission reductions if the underlying renewable power is also delivered to California with a zero-emission signature. The solution that has been proposed by the JUG is simply to not allow the underlying renewable power to be delivered to California without the associated RECs. This works, and appears to address the most significant of ARB concerns. SMUD believes that ARB should structure the restrictions on the RPS Adjustment to allow the underlying renewable energy to be delivered to a California balancing authority as unspecified power. This has the benefit of further conforming the fundamental RPS and Cap-and-Trade policies of the state, while preserving the environmental integrity of the Cap-and-Trade structure...

Increasing the conformance between the RPS and other complementary measures to lower demand prior to market prices rising to APCR levels. Some renewable procurement allowed under the RPS does not result in a lowered carbon obligation, which reduces the cost-containment impact of the program. This goes back to maintaining or even enhancing the treatment of RECs to reflect the impact on the atmosphere in the carbon obligation. (SMUD)

Comment:

[In a January 2016 letter to ARB, included as an attachment to their comments, the commenters and six other utilities state:]

The Utilities urge ARB to maintain and strengthen the RPS Adjustment sections of the Cap and Trade 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.³³⁹ The Utilities implore that Staff reconsider this position, which is inconsistent with both Legislative intent, as described below, but also historical ARB positions.³⁴⁰ 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)³⁴¹ 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.

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

³³⁹ 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>.

³⁴⁰ 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”)

³⁴¹ 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.

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."³⁴²

In a typical firming and shaping transaction, a Utility purchases bundled power from an eligible out-of-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 generated and delivered by an eligible renewable energy resource."³⁴³ The Legislature further stated that the REC conveys:

³⁴² Public Utilities Code §399.16 (b)(2)

³⁴³ Public Utilities Code §399.12 (h)(1)

*“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.”*³⁴⁴

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.”*³⁴⁵

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.”³⁴⁶

³⁴⁴ Public Utilities Code §399.12(h)(2) (emphasis added)

³⁴⁵ Public Utilities Code §399.13(a)(4)(C) (emphasis added)

³⁴⁶ 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 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.”).

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.³⁴⁷ 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.³⁴⁸ 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.

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:

³⁴⁷ CPUC Decision 08-08-028, at Appendix A-2.

³⁴⁸ 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).

A. Consider cost-effectiveness of these regulations: 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:³⁴⁹ 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:³⁵⁰ 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:³⁵¹ 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.

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

³⁴⁹ Id. at § 38562(b)(6).

³⁵⁰ Id.

³⁵¹ Id. at §38562(f).

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.”³⁵² 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 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-and-Trade allowances, despite their prior

³⁵² <http://www3.epa.gov/greenpower/gpmarket/rec.htm>

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~~ ["and for specified source" included in PG&E letter but not in MODESTOID letter] 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.~~ (PG&E, MODESTOID)

Comment:

Removal of the RPS adjustment penalizes early action, creates disparity with the RPS program and would drastically increase compliance costs to MID's ratepayers. MID strongly opposes the amendments discontinuing the RPS adjustment. The RPS adjustment is an essential provision of the Cap-and-Trade program and Mandatory Reporting Regulation (MRR) that recognizes the zero-emission attributes of energy resources that EDUs procured or contracted with prior to the inception of the Cap-and-

Trade program. Citing difficulty with validating claims of RPS adjustment energy and the potential for double-counting zero-emission energy, the Proposed Regulation Order proposes to eliminate the RPS adjustment in 2021. The JUG and its members have worked with ARB staff over the past year to preserve this important provision and have developed a simple, comprehensive solution that eliminates the risk of double-counting zero-emissions benefits and ensures that the entity that owns the renewable energy attributes of the imported electricity receive the compliance benefit in the Cap-and-Trade program.³⁵³ MID requests the Board to consider the solution proposed by the JUG.

Through meetings between the JUG and ARB staff, staff has proposed a replacement to the RPS adjustment that is not sufficient. The cost burden calculation that the EDU direct allocation will be based on assumes that all EDUs will maintain an RPS compliance of 33% RPS-eligible renewable energy through 2030. ARB staffs replacement to the RPS adjustment is to assume RPS compliance of 28%, thereby increasing the amount of an EDU's load that is assumed to be served by natural gas generation and increasing its cost burden, thus increasing its allowance allocation. The 28% RPS compliance figure is arrived at by assuming that all EDUs procure the maximum amount of PCC2³⁵⁴ energy allowed by the RPS program, which is 15% of an EDU's RPS compliance amount. However, one of the issues with this solution is that many EDUs, especially POUs like MID, have grandfathered, or PCCO in the RPS program, contracts that they entered into prior to the development of the Cap-and-Trade program that can exceed the PCC2 limit. ARB staff's RPS adjustment replacement does not recognize EDU ratepayers' investments in PCCO resources. MID will have 45% of its 2030 RPS compliance fulfilled by PCCO resources that are currently eligible for the RPS adjustment and that have contract terms extending past 2030, much greater than the 15% offered by ARB staff. If the RPS adjustment is eliminated and staffs replacement provision is adopted, MID's ratepayers will have to pay an additional \$31 million in Cap-and-Trade compliance costs over the period of 2021-2030³⁵⁵.

Additionally, our service area is almost entirely identified as a disadvantaged community. The rate increases triggered by this change would be counter to one of the tenets of the recently passed AB 197, which directs ARB to be mindful of the social costs of emissions reductions particularly those experienced by disadvantaged communities. Also, by failing to recognize the environmental benefits of the RPS grandfathered contracts, ARB will create disparity between California's two marquee environmental programs, the Cap-and-Trade program and the RPS mandate. MID

³⁵³ Attachment A to these comments was originally submitted by the JUG as comments to an ARB workshop discussing the RPS adjustment. The document describes the solution proposed by the JUG to keep the RPS adjustment while ensuring that double-counting is not possible by using Renewable Energy Credits (RECs) to identify ownership of the renewable qualities of a specific quantity of electric energy and thus preclude a third party from also claiming the renewable qualities, which they did not pay for.

³⁵⁴ The RPS "bucket 2" electricity, which is sourced from out-of-state firmed-and-shaped electricity contracts.

³⁵⁵ Based on the CEC's 2015 IEPR allowance price forecast.

requests that the RPS adjustment be retained and ARB staff continue to work with stakeholders to refine the provision within the Cap-and-Trade and MRR regulations. (MODESTOID)

Comment:

Instead, in furtherance of the State's emission reduction goals – and the underlying objectives of both the Cap-and-Trade and RPS programs – the zero-GHG value of renewable resources should continue to be recognized in the Cap-and-Trade Program through the RPS Adjustment. NCPA supports the proposal for amendments to the Cap-and-Trade Program Regulation and Mandatory Reporting Regulation (MRR) set forth in the January 15, 2016 from a coalition of California utilities (California Utilities' January 15 Letter).³⁵⁶ The California Utilities' January 15 Letter suggest revisions to the Cap-and-Trade Regulation and Mandatory Reporting Regulation that would ensure the regulations' existing terms are enforced and retain the value of the RPS Adjustment, such that:

- (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 power.

The California Utilities' January 15 Letter recognizes the key role RECs play in meeting the State's GHG reduction strategy, and aligns the RPS and Cap-and-Trade programs in a way that achieves these objectives and preserves the independent integrity of both programs within the context of commercial practices and transactions that are an essential part of the GHG reduction goals. As the California Utilities' January 15 Letter note,

“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.”

Furthermore, amendments to the MRR should not eliminate the requirement to report REC serial numbers; indeed, providing the REC serial numbers ensures that the entity entitled to the environment attributes (and the corresponding RPS Adjustment) can be verified. (NCPA)

³⁵⁶ The California Utilities' January 15 Letter is appended to the California Joint-Utility Group comments on the Proposed Amendments, dated September 19, 2016.

Comment:

The Joint Proposal Addresses the Stated Concerns: M-S-R understands and shares CARB staff's concern that the integrity of the Cap-and-Trade Program be preserved and that the state's emissions be accurately counted. However, eliminating the RPS Adjustment is not necessary to address those concerns. Indeed, eliminating the RPS Adjustment would result in greater compliance costs for covered entities and provide an inaccurate picture of California's true emissions associated with imported electricity. Rather than do away with this important cost-containment measure that helps to protect California ratepayer's long-term investments in renewable energy resources, the regulatory language should be amended to provide for greater clarity.

Amendments to the Cap-and-Trade Program and the Mandatory Reporting Regulation (MRR) will address both CARB staff and stakeholders' concerns without the need to eliminate the RPS Adjustment. Misunderstandings associated with utilization of the RPS Adjustment are the result of differing interpretations of language found in the Cap-and-Trade Regulation and the MRR. On January 15, 2016, a coalition of California utilities presented CARB with proposed amendments that would address the stated concerns. Modifications to the regulatory language in both regulations to ensure consistency and clarity should go far to ameliorate the current issues regarding RPS Adjustment claims and ensure that only the entity with title to the environmental attributes (renewable energy credits or RECs) would be qualified to claim the import as specified power and utilize the RPS Adjustment, therefore, removing the potential risk of double counting that claim. Implementing these changes will also make certain that the total emissions attributed to compliance entities like EDUs with contracts for zero-emission renewable energy are accurate. Under the current structure, even when entities like M-S-R settle their transactions contractually, the final emissions factor attributed to the utility does not reflect the zero emissions from the renewable resource, thus providing an inaccurate picture of their emissions profile. The proposed changes address concerns about double counting and program integrity, which can be entirely eliminated by acknowledging REC ownership for purposes of claiming the adjustment. (M-S-R)

Comment:

JUG members have worked together to submit 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. [The comment letter did not actually include an Appendix A. If the commenter is referring to Appendix A or Appendix B included in the JOINTUTILITIES first 15-day comment letter, see first 15-day comments B-1.1.] (JOINTUTILITIES)

Comment:

The CPUC and the California Energy Commission (CEC) are required to implement the RPS program to attain 20 percent of total sales of electricity in California from eligible renewable energy resources by 2013, 33 percent by 2020, and 50 percent by 2030.³⁵⁷ The RPS statute identifies the electricity products that are eligible to comply with the RPS procurement Ratepayer Advocates in the Gas, Electric, Telecommunications and Water Industries requirements.³⁵⁸ The CPUC and the CEC track RPS procurement through Renewable Energy Credits (RECs) that are assigned to eligible renewable generation³⁵⁹. The RPS program allows procurement of renewable resources through three portfolio content categories (PCC or buckets):

(1) PCC1, applicable to directly delivered electricity-facilities with a first point of interconnection within the California Balancing Authority (CBA) or with generation scheduled in the CBA; (2) PCC2, applicable to incremental electricity and substitute energy; and, (3) PCC3, electricity products not qualifying for the first two categories, including unbundled³⁶⁰ RECs.

Under ARB's Cap-and-Trade program, entities that import electricity to California are responsible for the GHG emissions associated with those imports.³⁶¹ If the imported electricity is procured from a "specified"³⁶² source of electricity outside of California, then the associated emissions compliance obligation is equal to known emissions. If the electricity is imported from an "unspecified"³⁶³ source, then the emissions compliance

³⁵⁷ Public Utilities Code Section 399.11 (a).

³⁵⁸ Public Utilities Code Section 399.16.

³⁵⁹ Public Utilities Code Section 399.21.

³⁶⁰ Public Utilities Code Section 399.16.

³⁶¹ Electricity that is "directly delivered" into California should qualify for PCC 1 of the RPS. ARB requires that imported electricity must meet any of the following criteria to be considered directly delivered into California:

- (A) The facility has a first point of interconnection with a California balancing authority;
- (B) The facility has a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area;
- (C) The electricity is scheduled for delivery from the specified source into a California balancing authority via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink located in the state of California; or
- (D) There is an agreement to dynamically transfer electricity from the facility to a California balancing authority." <https://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-2013-clean.pdf>.

³⁶² "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB." Title 17. Public Health-- Division 3. Air Resources--Chapter 1. Air Resources Board--Subchapter 10. Climate Change-- Article 2. Mandatory Greenhouse Gas Emissions Reporting--Subarticle 1. General Requirements for Greenhouse Gas Reporting).

³⁶³ "Unspecified source of electricity" or "unspecified source" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity." *Ibid*

obligation is determined by multiplying a default emission factor (0.428 MTCO_{2e}/MWh) by the amount of electricity (MWh) delivered.

Under the state's RPS program requirements, a utility may meet its compliance obligations in part, by purchasing low-emission or carbon-free power generation outside of California that is never delivered to serve load into the state. Under such instances, as is the case under PCC 2 of the RPS program, a utility can apply an RPS Adjustment factor,³⁶⁴ which would reduce the utility's GHG compliance obligation under Cap-and-Trade regulations.

The ARB's Final Statement of Reasons notes that:

"ARB included the RPS adjustment for the specific purpose of reducing the cost of RPS compliance that would be born directly or indirectly by entities that must comply with California's RPS program. The adjustment is impartially applied to any electricity importer that meets the requirements in section 95852(b)(4) of the cap-and-trade regulation to deliver RPS electricity used for RPS compliance."³⁶⁵ ³⁶⁶

³⁶⁴ The RPS adjustment is calculated as the product of the default emission factor for unspecified sources factor (0.428 MTCO_{2e}/MWh) multiplied by the amount of imported electricity subject to specific requirements under ARB's regulations. *Ibid.*

³⁶⁵ ARB Final Statement of Reasons for Rulemaking: Public Hearing to Consider Adoption of Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. October 28, 2011, pp. 365-375.

³⁶⁶ Reference Section 95852(b)(4): RPS adjustment: Electricity procured from 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 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 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 5852(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 specified in section 95111(g) of MRR for 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 an eligible renewable energy resource when its electricity is directly delivered.
- (E) No RPS adjustment may be claimed for electricity generated by an eligible renewable energy resource in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12.

Only RECs representing electricity generated after 12/31/2012 are eligible to be used towards the RPS adjustment.

Utilities are allowed to meet RPS program goals using RPS PCC 2 as defined in Section 399.16 (b) (2) of the Public Utilities Code.³⁶⁷ The power that serves load in California procured as PCC 2 can be firmed and shaped (using incremental electricity and substitute energy). However, under ARB's current accounting rules, while PCC 2 renewable power is eligible to meet the RPS program goals for renewable power, a utility may be assigned a GHG compliance obligation for the PCC 2 renewable power.

Due to differences in treatment of such imported power under RPS program rules and the ARB regulations, ratepayers are at risk for paying for GHG compliance resulting from RPS procurement. Under ARB regulations, covered importers of renewable power are required to report and surrender the RECs associated with the imported power in order to claim the RPS adjustments. However, if the imported renewable power is firmed and shaped, ARB does not allow the importer who owns the RECs to claim the RPS adjustment. Instead, the electricity is assigned the default emission factor for unspecified power and is subject to a GHG compliance obligation pursuant to ARB accounting rules. In this situation, after paying a renewable premium for RECs in compliance with the RPS program, an importing utility (and therefore its ratepayers) is still obligated to pay GHG compliance costs pursuant to ARB rules.

In addition, in the event that a third-party purchases and imports null power (renewable power without the RECs), the imported power is assigned a zero emission factor with no Cap-and Trade compliance obligation. In this situation, despite the fact that the null power is considered and priced as "brown" or non-renewable power under RPS program rules because the RECs have been stripped, the third-party importer has no GHG compliance obligation per the ARB rules, yet the utility that purchased the power for its RECs is not allowed to use the RPS adjustment.³⁶⁸

While ARB is correctly concerned about accurate accounting of GHG emissions from imported power serving load in California, accurate accounting should not preclude the application of rules that complement the existing RPS regulations, and should not impose additional emissions compliance costs on ratepayers without providing commensurate value. The CPUC and CEC track RPS procurement through RECS. ARB should require entities importing null power (i.e. renewable power without RECS) to procure GHG compliance instruments. Similarly, utilities importing renewable power under PCC 2 should be allowed to claim the RPS adjustment, as long they surrender associated RECs. ORA recommends that ARB staff consider the recommendations proposed by the investor-owned utilities regarding RPS Adjustments provided in

³⁶⁷ Under RPS rules, one of the portfolio content categories of eligible renewable energy resources, as defined in PU Code 399.16 (b) (2) is: "Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California Balancing Authority."

³⁶⁸ Thus, the GHG compliance costs are passed on to ratepayers when (1) a utility imports renewable electricity under RPS PCC 2 to comply with RPS goals, and the underlying power is delivered into California by a third-party; and (2) a utility imports renewable electricity to comply with RPS goals, but the renewable power is not delivered to California, and firmed and shaped power is delivered instead.

response to ARB's questions at the ARB/Joint Utilities Group meeting held in March of 2016.³⁶⁹

ARB included the RPS adjustment for the specific purpose of reducing the cost of RPS compliance. Maintaining the RPS adjustment under the Cap-and-Trade regulation is crucial not only to ensure that ratepayers are not forced to pay twice for complying with the state's GHG Cap-and-Trade regulations, but also to maintain the benefits of Californians' investments in clean energy. (OFFICERATEPAYERADVCT)

Comment:

In order to address the ARB's concerns associated with meeting the "direct delivery" prohibition in the RPS adjustment requirements, the ARB should require that any "null power" (i.e., the energy sold from the resource that does not contain the green attributes), be assigned the "unspecified"³⁷⁰ emissions rate. This would not require a regulatory change, but only require the ARB to enforce the requirement that electric power entities must report the REC serial numbers from eligible renewable resources. Enforcement of this requirement would ensure that California's ratepayers benefit from their purchase or investment in "green attributes" of out-of-state renewable resources.

TID does not agree with the suggestion that assigning an unspecified emissions factor to null power would constitute a violation of the Dormant Commerce Clause. A state law violates the Dormant Commerce Clause when the law discriminates against out-of-state competition to benefit local economic interest, or is unduly burdensome on interstate commerce.³⁷¹ The proposal to require null power be reported as unspecified is not an attempt to control prices on the face of the regulation and therefore is not a violation of the Dormant Commerce Clause. Moreover, California's interest in protecting and preserving its air quality justifies any incidental burden the enforcement of the REC serial number reporting requirement may pose for entities that knowingly purchase null power without the green attributes from a renewable energy resource.

If the ARB moves forward with its proposal to retract the REC serial number reporting requirement, TID will none-the-less take all steps possible to ensure that that energy which has been sold as null power will not be delivered back to California. Because TID owns its grandfathered resource, and is a scheduling coordinator, TID is able to view all e-tags to confirm how much, if any, null power has been delivered back to California. TID therefore opposes the removal of the RPS adjustment and its replacement with the flat allowance allocation to EDUs at the maximum PCC-2 limits. (TURLOCKID)

³⁶⁹ https://www.arb.ca.gov/cc/capandtrade/meetings/informal/pg_e_comment_7.pdf

Cap-and-Trade regulations, but also to maintain the benefits of Californians' investments in clean energy.

³⁷⁰ That is, it should carry a carbon emissions rate as determined by the State recognizing the aggregate carbon intensity of the resources that are not specified and sold as renewable.

³⁷¹ See *C&A Carborne, Inc. v. Town of Clarkstown*, 511 U.S. 583 (1994); *Pharmaceutical Research and Manufacturers of America v. Walsh et al*, 538 U.S. 644 (2003); *Maine v. Taylor*, 476 U.S. 1138 (1986); *Rocky Mt. Farmers Union v. Corey*, 730 F.3d 1070 (2013).

Comment:

B. The RPS Adjustments Plays an Important Role in Reducing GHG Emissions and Should Remain Part of the Cap-and-Trade Regulation

SDG&E urges the Board to continue the RPS Adjustment as it was intended to be used by the Board and to adopt SDG&E's proposed clarifications to the RPS Adjustment.³⁷² As SDG&E discussed in its January 4, 2016 comment letter, these clarifications support a plain meaning interpretation of the regulations, while maintaining the integrity of the cap-and-trade program and protecting the significant early investments in renewable energy made by utilities on behalf of California ratepayers.

ARB Staff, however, has not incorporated the clarifications into the draft amendments to the regulations. Instead, Staff has proposed eliminating the RPS Adjustment after 2020. These Staff-proposed changes fail to recognize the RPS program's important role in reducing GHG emissions.³⁷³ These actions (1) unfairly change the rules for claiming the RPS Adjustment as codified in the plain text of the regulations as adopted by the Board, (2) devalue California utilities' significant investments in renewable electricity, (3) increase the cost of investments in renewable electricity, and (4) increase barriers for California to achieve its 2030 goals for reducing GHG emissions. To avoid these undesirable policy outcomes, SDG&E requests that the Board reject Staff-proposed changes that complicate demonstration of GHG reductions of out-of-state renewables deemed delivered to California by the CEC and decline to eliminate the RPS adjustment post-2020.

The SDG&E-proposed clarifications would confirm that an out-of-state importer must meet all existing criteria for delivered electricity from a specified source, including provision of REC serial numbers, to report the electricity as a specified renewable. If the out-of-state importer cannot meet criteria, it must report the electricity as unspecified power or from an asset-controlling supplier. The entity that owns or has permission to use the RECs would claim the renewable attribute of that electricity as an RPS Adjustment, offsetting the emissions of the substitute power imported under the cap-and-trade program.

SDG&E Recommendation: The Board should adopt the SDG&E-proposed revision to section 95852 (b)(4) clarifying that an RPS Adjustment cannot be claimed for electricity that meets the criteria of section 95852 (b)(3). Together, these revisions will maintain the environmental integrity of the cap-and-trade program and protect the GHG benefits of California ratepayers' significant investments in renewable electricity.

³⁷² SDG&E, Pacific Gas & Electric Company, and Southern California Edison Company detailed these clarifications in their October 19, 2015 comment letter, which is attached.

³⁷³ See the attached January 4, 2016 SDG&E comment letter.

(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.

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

Comment:

Throughout the numerous meetings on this topic, the Joint Utilities Group has presented ARB staff and managers with a counter proposal which SCPPA believes achieves the goals of both ARB and stakeholders. This proposal has not yet been responded to by ARB staff. SCPPA requests an in-depth analysis of the proposal prior to the regulation being finalized. (SCPPA)

Comment:

IF THE RPS ADJUSTMENT IS TO BE DISCONTINUED AFTER 2020, THE ARB SHOULD DEVELOP A TRANSPARENT AND NONDISCRIMINATORY MECHANISM FOR ALLOCATING ADDITIONAL ALLOWANCES

If the RPS adjustment is to be discontinued after 2020, and if additional allowances are to be allocated to first deliverers of electricity for imports of renewable energy that cannot be delivered to California in real-time, calculation of the additional allowance allocation must be transparent. If the allocation of additional allowances will decline over time, the ARB should publish the process for reducing the additional allowance allocation for all first deliverers of electricity. The allocation of these additional allowances should be proportional for all first deliverers of imported energy.³⁷⁴ In addition, the allocation of additional allowances to all first deliverers should decline at the same rate over time, based on the amount reported in the baseline year. (SHELL)

³⁷⁴ Elimination of the RPS adjustment without any additional allocation of allowances to mitigate the increased GHG compliance costs would at least treat all first deliverers even-handedly.

Comment:

I'm here to explain why the RPS adjustment is so important to SDG&E and to ask that the Board retain its original approach to the RPS adjustment, to continue to recognize the early investment that utilities have made on behalf of their ratepayers in renewable electricity.

For SDG&E that's meant contracts that have started as early as 2008 and that extend as far as 2033. These contracts assign renewable energy credits, RECs, to SDG&E that under the current approach represent a compliance cost reduction for our ratepayers of seven to eight million dollars per year. These RECs also represent up to 20 percent of SDG&E's renewable portfolio.

If the Board were to depart from its original approach to the RPS adjustment, our invest – our ratepayers would no longer be able to get the benefit of these investments. Instead, a windfall would go to the out-of-state importers that brought in the electricity that then had stripped of these RECs and imported into California.

As noted in written comments submitted by SDG&E, other utilities these, and the California Public Utility Commission's Office of Ratepayer Advocates, that does nothing to reduce GHG emissions, and the penalty to ratepayers is not good policy.

Ideally, the Board would continue with its original approach to the RPS adjustment and adopt the clarifying regulatory provisions that SDG&E and other utilities have proposed. These clarifications would address the double-counting certain by confirming that any electricity that's imported into California that has been stripped of its RECs by contract is brown electricity.

And the clarifications also confirm that the only entities that can claim the RPS adjustment are those that hold RECs as tracked by a well proven system to track the serial numbers for those RECs.

If the Board is willing to adopt those clarifications and continue this approach, it will ensure that the Cap-and-Trade's Program continues to apply consistently and fairly to all ratepayers including SDG&E's. (SDG&E2)

Comment:

The ARB Should Retain The RPS Adjustment And Clarify Its Guidance Language To Require That the Direct Delivery of Null Power Be Reported As Unspecified Imports.

The RPS Adjustment is a critical component of the Cap-and-Trade Regulation that should not be removed. The RPS Adjustment ensures that utilities, like TID, that made early, voluntary investments in out-of-state renewables are able to utilize zero emissions resources without paying a substantial and unjustified carbon price that devalues the early investment and doesn't fairly recognize a zero net carbon emissions source. At the time that TID made its investment, the State encouraged "firming and shaping contracts" and allowed utilities to meet 100% of the RPS obligations with this contract

structure. TID currently utilizes its “grandfathered resource” to meet the vast majority of our RPS compliance obligation. Removing the RPS adjustment will considerably increase the cost to the District which is ultimately placed on our customers. The proposed allocation of allowances to electric distribution utilities would not adequately address this cost because the free allocation would decline over time, and as currently proposed, would not distinguish grandfathered resources. The ARB should therefore retain the RPS adjustment. (TURLOCKID)

Comment:

The following comments are related to the proposed removal of the requirement to report REC serial numbers for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emission factor or asset controlling supplier emission factor. This is the proposed change to Sec. 95852.b.3.D (p.126) of Proposed Regulation Order.

We submitted comments to ARB in March of this year explaining the risk of double counting associated with removal of the existing REC reporting requirement for specified imports. Those comments are summarized below along with additional information.

There is risk of double counting with other state programs if the REC is not required with specified renewables imports.³⁷⁵ The proposed removal of the existing REC reporting requirement for specified imports increases this risk of double counting.

ARB should not ignore the mechanisms and instruments used in the broader electricity market for tracking RE delivery in the design and implementation of California’s cap-and-trade program. There will be double counting of zero-emission power if energy is imported without the REC, counted as zero emissions specified power, and then the associated REC is counted as zero emissions by another program, e.g. toward the Oregon RPS. RECs are therefore critical in this context to prevent double counting with other programs and policies. RECs are the currency for zero-emission electricity delivery and consumption in state compliance markets and the voluntary renewable energy market. Where neighboring state programs count renewable energy, using RECs, that is also being counted as zero emissions power delivered to California, this affects the integrity of both state actions equally. One could characterize this as leakage for California’s cap-and-trade as it allows null power (electricity without RECs or for which the RECs are sold out of state) to be imported without emissions.

The Western Renewable Energy Generation Information System (WREGIS) cannot currently be used to prevent this double counting. WREGIS does not create e-tags. Rather, they are provided to WREGIS and imported into the WREGIS system. Account

³⁷⁵ March 4, 2016. Comments of Center for Resource Solutions (CRS) in response to February 24, 2016 Workshop on Potential Amendments to the Greenhouse Gas Mandatory Reporting and Cap-and-Trade Regulations. Available online: http://resource-solutions.org/site/wp-content/uploads/2016/03/CRScommentstoARB_3-4-2016.pdf.

holders who have signed up for the functionality are responsible for matching their e-tags to their RECs. E-tag information is considered confidential, unless the account holder chooses to release such information to their counterparties. This means that certain parties can see e-tags with RECs in WREGIS but only if the account holder has matched their e-tags and RECs and only if the account holder has chosen to release that information. This is not sufficient to prevent double counting. Even if states or Green-e could require that regulated entities/sellers with WREGIS accounts match e-tags to RECs and make this information available in WREGIS, there would be no way to see if the underlying power associated with RECs was imported into California by a previous or different seller or importer.

Removal of the existing REC reporting requirement for specified imports increases the risk of double counting within the Clean Power Plan (CPP).

The CPP is another reason not to remove the requirement for REC reporting for imports. Thinking about the same scenario as above, if Oregon (or any other state in the Western Electricity Coordinating Council) were also to adopt a mass-based state measures plan and include its RPS as a state measure, it could get CPP compliance credit for electricity that was counted as zero emissions in California, resulting in double counting between California and Oregon within the CPP. In other words, Oregon can use the REC for RPS compliance, which is a state measure under the CPP, while at the same time, California also counts the electricity from that same unit of generation toward its CPP compliance using cap-and-trade.

Standardization of REC serial number reporting and better enforcement of the requirement would help to mitigate administrative challenges associated with the existing REC reporting requirement for specified imports, which nevertheless do not compel its removal.

To avoid inconsistency in REC serial number reporting among reporters, we recommend that ARB standardize REC serial reporting, such that it allows ARB Staff to identify individual RECs reported with specified imports.

Regardless of whether the import is counted as specified by rule if the entity is a generation providing entity (GPE), REC serial number reporting is required and ARB Staff must address any non-conformance to the requirement.

The existing REC reporting requirement for specified imports could, in fact, be strengthened in order to prevent double counting with other state programs.

Ideally, ARB must ensure that RECs associated with imported electricity do not leave the state once a MWh is imported without emissions. REC reporting, as opposed to retirement, is only appropriate to prevent double counting if the importer is not itself delivering to load and the REC stays in state and the electricity is not wheeled out of state as zero-emissions electricity. If the importer is delivering directly to end users, including for the RPS, then retirement of the REC should be required to prevent double

counting. And if the REC is traded out of state to be used in a different system by either the importer, an in-state load-serving entity (LSE), or other entity after the REC has been reported by the importer to avoid a compliance obligation, then there is double counting.

We recommend that the list of REC serial numbers associated with specified imports be given to WREGIS and that WREGIS be used to confirm that those RECs were retired in California or by a California user at the time of compliance. We have significant experience with helping states use tracking systems to verify different regulatory requirements. We would be happy to help ARB and WREGIS create the functionality needed. (CRS)

Comment:

A. Proposed Staff Changes to Direct Delivery Will Increase Leakage

The cap-and-trade regulation as adopted by the Board and approved by the Office of Administrative Law in 2011 required direct delivery of renewables to include the retired RECs associated with the electricity delivered. The specific language of section 95852(b)(3)(D) states unambiguously, “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.” The cap-and-trade regulation requirement as written and implemented in 2013 required that the energy from directly delivered renewables must be bundled with their RECs. This regulation worked well in 2013. The bundling requirement was made optional by ARB Staff in July 2015, and ARB Staff made all affected entities change their 2013 and 2014 compliance reports. This change created difficulties with the RPS Adjustment compliance since the straight-forward use of RECs could not be used to show emissions reductions for this out-of-state power. The accounting is so difficult that ARB Staff has proposed to remove the RPS Adjustment and ignore the GHG reductions from these renewables deemed delivered to California by the California Energy Commission (CEC). But equally important, this change may promote significant leakage.

Under the regulation as adopted by the Board in 2011, the requirement to provide RECs assured that the supplied electricity was from incremental renewable resources built to reduce GHG of California’s electric sector. Staff’s reinterpretation of 95852(b)(3)(d), and deletion of the section in the proposed regulation, opens the door for specified resource contracts with existing out-of-state resources. Any new importer would be free to sign contracts with renewables built to meet RPS standards in surrounding states and existing hydroelectric facilities. The other state would get the RPS credit, while the California importer would simultaneously be able to “directly deliver” renewable energy without the RECs. This could create significant leakage as fossil resources likely would backfill the exports to California to replace the power originally built to serve load in the exporting state, the so-called “secondary effect.” The Board has an obligation to

minimize leakage and should do so by rejecting Staff's interpretation and proposed regulation change.

SDG&E Recommendation: The Board should reject Staff-proposed deletion of section 95852 (b)(3)(D) and require ARB Staff to interpret the regulation as written. Alternatively, the Board could adopt the SDG&E-proposed revision to section 95852(b)(3), which 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 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.

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 an unspecified source pursuant to section 95852(b)(1)(C).

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

(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 and verify its exclusive rights to the RECs (i) as the facility operator with retained rights to the RECs or (ii) by having the right of ownership or a written power contract, as defined in MRR section 95102(a). (SDGE)

Comment:

ARB Should Recognize the Value that Firm and Shaped Transactions Provide Utilities Because the Legislature Allows Firm 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."³⁷⁶

In a typical firming and shaping transaction, a Utility purchases bundled power from an eligible out-of-state generator. The underlying electricity associated with the renewable power is re-sold to a third party as "null" power, which is widely understood

³⁷⁶ Public Utilities Code §399.16 (b)(2)

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.

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 generated and delivered by an eligible renewable energy resource."³⁷⁷ 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."*³⁷⁸

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:

³⁷⁷ Public Utilities Code §399.12 (h)(1)

³⁷⁸ Public Utilities Code §399.12(h)(2) (emphasis added)

*“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.”*³⁷⁹

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

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."³⁸⁰ 0.08-08-028 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.³⁸¹ As a result, many of those firming and shaping transactions of concern to the ARB contain specific commercial terms required by the

³⁷⁹ Public Utilities Code §399.13(a)(4)(C) (emphasis added)

³⁸⁰ CPUC Decision ("D.") 08-08-028, at Ordering Paragraph I, available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/86954.pdf. The Decision did not direct the ARB or other 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.").

³⁸¹ CPUC Decision 08-08-028, at Appendix A-2.

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.³⁸² 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. (MODESTOID)

Comment:

2. ARB Should Align the Proposed Amendments to Cap and-Trade Regulations with the RPS program.

The ARB's proposal to address the EIM and proposed expansion of the CAISO to include other Balancing Authority Areas (BAAs) in the west explains that:

"emissions leakage occurs when it appears there has been a GHG emissions reduction through accounting for California program purposes, but the atmosphere did not actually experience that real GHG reduction." ³⁸³

While ORA agrees with ARB's explanation of the emissions leakage under this context, it is not clear if ARB is characterizing the emissions resulting from meeting RPS goals with PCC2, as discussed above, as "leakage." ORA recommends that ARB align its accounting of GHG emission reductions associated with PCC2 with RPS regulations. As stated earlier, ratepayers should not pay twice for complying with the state's RPS and Cap-and Trade regulations.

In the instances where an EIM purchaser imports renewable power to meet RPS goals, pursuant to PCC2 rules, the EIM purchaser should be allowed to claim the RPS

³⁸² 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.

³⁸³ ARB Staff Report, p. 51.

Adjustment under current Cap-and-Trade Regulations, given that the EIM importer surrenders the RECs associated with that power.

If ARB rules are not accurately aligned with existing RPS program rules, GHG compliance costs passed on to ratepayers may increase due to this misalignment, even though there may be no increase in GHG emissions (OFFICERATEPAYERADVCT)

Response: Many commenters request confirmation from staff that the RPS Program results in GHG emissions reductions and plays a large role in the State meeting its emissions reductions goals. Staff confirms that, and notes we have never disputed this fact, and have emphasized it in the Climate Change Scoping Plan and 2014 First Update to the Scoping Plan,³⁸⁴ and in associated presentations. Commenters also request that ARB generally harmonize the Cap-and-Trade and RPS Programs where appropriate, and consult with CPUC on alignment of these programs. Staff notes that, in adopting the Cap-and-Trade Regulation and MRR in 2010, we did adopt accounting methodologies in MRR (i.e., specified source reporting requirements) to accurately account for the GHG emissions from out-of-State sources, and both regulations include the RPS Adjustment to reduce the compliance obligation and appropriately recognize RPS cost burden. In structuring the reporting requirements, staff consulted extensively with CPUC staff and, over the years, has continued to consult with CPUC staff about these and other intersections between the Cap-and-Trade Program and the RPS Program.

Many commenters suggest that staff modify the accounting of zero-emission power under MRR by assigning zero emissions to the RECs, as opposed to the directly delivered electricity into the State, as a means of better aligning the Cap-and-Trade and RPS Programs. Along the same lines, some commenters argued that, instead of removing the section 95852(b)(3)(D) requirement to report RECs for specified sources, ARB should enforce that requirement. Staff notes that, though reporting of RECs was required via this provision of the regulation, failure to report REC serial numbers associated with specified source imports has always³⁸⁵ represented a nonconformance with MRR, rather than resulting in an adverse verification statement. Specified source emission factors assigned by ARB must still be used to calculate emissions associated with the imported electricity from a specified source for which no RECs are reported. Further explanations of why ARB relies on source-specific GHG emissions reporting rather than reporting of RECs for GHG emissions accounting of renewable resources are included in the 2010 Cap-and-Trade Regulation FSOR, as referenced above, as well as the 2010 MRR FSOR.³⁸⁶

³⁸⁴ <https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm>

³⁸⁵ See pages 2110 and 2115 of the 2010 Cap-and-Trade Regulation Final Statement of Reasons (<https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>).

³⁸⁶ e.g., pages 108 and 110, <https://www.arb.ca.gov/regact/2010/ghg2010/mrrfsor.pdf>.

Some commenters argue that implementation of the RPS Adjustment and specific source reporting requirements have limited the usefulness of the RPS Adjustment and results in unexpected costs to ratepayers, and request additional allocation for “firmed and shaped power.” In response to these comments, staff notes that over \$1 billion in value is provided to EDUs in the form of allowance allocation for ratepayer benefit every year. Staff has also dedicated considerable time to working with reporting entities to facilitate accurate reporting of any RPS adjustment claims for which entities may be eligible. Further, staff notes that, in calculating the post-2020 EDU allocation for the second 15-day regulatory change proposal, staff decreased the assumptions about zero-emission power (i.e., power that has no Cap-and-Trade Program cost) to recognize that not all RPS-eligible power will have zero compliance obligation under the Regulation. ARB staff believes this change helps address the commenters’ concerns.

RPS Adjustment vs. Allocation with Reduced RPS Power Assumption

D-3.3. Multiple Comments:

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 proposed amendments do include an alternative method of compensation to account for the cost of these renewable investments in the form of a flat percentage increase in allowances factored into the calculation of each utility’s allowance allocation. 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 provide protection for ratepayers commensurate with the RPS Adjustment as had been expected when implemented. Furthermore, the flat percentage number proposed does not recognize the varying number of firmed and shaped contracts (and associated cost exposure) held by different utilities, the fact that the limit on Portfolio Content Category 2 (PCC2) contracts under the RPS is 66% higher than the ARB proposal presumes, or the fact that firmed and shaped grandfathered resources for any utility are not accounted for in the proposal and may exceed the PCC2 procurement limits. The ARB proposal also negatively impacts the economic viability of future firmed and shaped contracts, which will lead to higher costs to California ratepayers to achieve the RPS and carbon goals. The JUG recommends that the ARB retain the RPS adjustment, and work with affected stakeholders to revise the guidance language. (JOINTUTILITIES)

Comment:

ARB staff has discussed the concept of reducing total load by less than the full 33% RPS target as a way to compensate utilities for the removal of the RPS Adjustment. SCPPA does not believe this is an equal trade and would prefer to see the retention of the RPS Adjustment over an allocation adjustment (see RPS Adjustment comments). Some utilities would potentially optimize their portfolio by maximizing their option for

contracts that currently are able to utilize the RPS Adjustment - which is greater than the 15% adjustment ARB staff is proposing, resulting in greater cost burdens than the allocation accommodates; however, other utilities may not utilize this option at all and will be provided more allocation than accurately reflects their cost burdens. (SCPPA)

Comment:

The CCAs also oppose the proposal to replace the RPS Adjustment by allocating allowances to Electricity Delivery Utilities (EDUs). This alternative mechanism excludes CCAs, which have invested more heavily in renewable resources, as a proportion of total resource commitments, than the Investor Owned Utilities (IOUs). As an unintended consequence, CCAs would suffer competitive disadvantages against their incumbent IOUs – with customers in CCA territories held responsible for corresponding costs, which are expected to increase for Portfolio Content Category 2 (PCC-2) products, as allowed for use under California’s RPS Program, following elimination of the currently applicable RPS Adjustment. (JOINTCCAS)

Comment:

In lieu of continuing the RPS Adjustment, the Staff Report proposes to address RPS program impacts through allocation of allowances directly to the EDUs. Instead of the RPS Adjustment, post-2020, EDUs would get allowances “that accounts for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California.” (Staff Report, p. 53) This alternative, however, is not a comparable substitute for the RPS Adjustment, nor does it reflect all of the same policy issues that were addressed by the RPS Adjustment. As such, the adverse impacts on EDUs associated with elimination of the RPS Adjustment would not be mitigated or alleviated by the allocation of free allowances to EDUs. The staff proposal would allocate allowances based on the maximum allowable quantity of Portfolio Content Category (PCC) 2 resources (as defined in PUC section 399.16(b)(2) and (c)). This proposal assumes that all utilities have the same amount of PCC 2 resources, which is not the case. The allocation under this proposal also fails to account for procurement of additional PCC 2 resources or amendments to existing contracts that would change the PCC 2 quantity acquired after the initial allowance allocation methodology is established. The Staff proposal is also insufficient due to the fact that it ignores those RPS-eligible resources authorized in PUC section 399.16(d) and deemed PCC 0. Unlike the RPS Adjustment which is directly tied to the actual quantity of renewable resources imported, the quantity of allowances that would be allocated to EDUs under the alternative proposal would be subject to the declining cap. At the same time, EDUs subject to the RPS mandate will be required to procure increasingly greater quantities of renewable energy, thus, over time, the allocation will not fully “account[] for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California.” It is also worth noting that the potential expansion of the ISO and California’s participation in a regional grid could also impact out-of-state RPS resources. The extent of those impacts could vary, as resources could be delivered into a larger

grid under a regional ISO, altering electricity delivery, but not the underlying REC ownership. Allowance allocation to “replace” the RPS Adjustment must be based on actual purchases in order to align the renewable electricity purchase with the Cap-and-Trade program compliance obligation. NCPA is also opposed to the proposal to remove the RPS Adjustment and replace it with an allowance allocation because it results in an inaccurate depiction of the EDU’s actual GHG emissions, overstating the emissions profile since GHG-free RPS resources would be assigned a GHG compliance obligation. The value associated with the freely allocated allowances does not offset the higher compliance costs that will result if the RPS Adjustment is eliminated, nor is it an efficient use of allowance value to pay for the same emission reduction twice... (NCPA)

Comment:

Allocation of Allowances Based on a Set Percentage of the RPS Program Purchases of Portfolio Content Category 2 Resources is an Ineffective and Insufficient Replacement for the RPS Adjustment: As part of staff’s proposal to eliminate the RPS Adjustment beginning in 2021, staff contemplates allocating allowances to the EDUs “that accounts for RPS-eligible electricity that is purchased together with RECs but cannot be directly delivered to California.” (Staff Report, p. 53) The specific details regarding the manner in which this allocation would be calculated are still outstanding and will likely not be fully developed until 15-day language.

However, as currently contemplated, allowances intended to replace the RPS Adjustment would be based on a quantity of Portfolio Content Category (PCC) 2 allowances defined in Public Utilities Code (PUC) section 399.16(b)(2) and (c). This proposal suffers from several significant infirmities. First, not all utilities have the same amount of PCC 2 resources; to the extent that allocation of allowances is to be determined based on the EDU’s cost burden, the amount of PCC 2 resources at issue must be factored in. Second, a one-time allocation would not take into account future PCC 2 contracts or changes to existing agreements. The ever increasing RPS mandate, coupled with what will be escalating Cap-and-Trade compliance costs under a declining cap, make it imperative that EDUs retain the maximum flexibility in their renewable resource procurement plans going forward. Third, the proposal does not address RPS Program resources deemed PCC 0 by the CEC, as defined in PUC section 399.16(d). M-S-R members have significant investments in renewable resources that meet the PCC 0 statutory requirements, but would be wholly unacknowledged under the current proposal. As noted above, the financial implication of eliminating the RPS Adjustment associated with these resources is considerable; the proposed allowance allocation alternative does not address them all. Fourth, the quantity of allowances allocate would be subject to the declining cap, while procurement associated with these RPS-eligible resources would not. Finally, as noted above, while allocating allowances would at least help to offset the increased compliance costs that would result from the change in policy regarding the treatment of these RPS-eligible

resources, it would not address the misrepresentation of the EDU's actual GHG emissions. That is because it would still require a GHG compliance obligation for imports of zero-GHG emission resources. For all of these reasons, staff's proposed alternative fails to adequately address the gap that would ensue should the RPS Adjustment be eliminated. (M-S-R)

Response: Commenters state that an EDU-uniform increase in post-2020 allocation to cover the cost burden associated with the increased compliance obligation associated with the removal the RPS Adjustment will neither be sufficient nor equitable. In response to these comments, and other comments that the RPS Adjustment is a necessary tool, staff made modifications in the first and second 15-day packages of this rulemaking to both retain the RPS Adjustment in the Regulation and, in calculating post-2020 EDU allocation, decreased the assumptions about zero-emission power (i.e., power that has no Cap-and-Trade Program cost) to recognize that not all RPS-eligible power will have zero compliance obligation under the Regulation. Together, these two changes provide EDUs appropriate ratepayer protection.

D-4. Voluntary Renewable Energy (VRE)

Opposition to Ending Allowance Allocation to VRE Reserve Account

D-4.1. Multiple Comments:

Another clear example of the need for additional regulatory certainty is the proposed lack of allocations of post-2020 allowances to the Voluntary Renewable Energy Program (VREP). The previous lack of demand for allowances for the VREP is not indicative of future demand, as many California utilities are just getting their green rate programs off the ground, and Senate Bill 350 removes barriers for POUs to develop and pursue such programs. This is a clear example where utilities created their own programs to further state goals and increase customer choice. The VREP is the primary mechanism for ensuring the participants in these voluntary programs that their participation is actually reducing GHG emissions.

Without the VREP, these programs are likely to suffer. JUG members believe the continuation of the VREP allowance set-aside should be an ARB priority, and we would like to continue the discussion regarding how those allowances may be sourced from the overall Cap-and-Trade program cap. (JOINTUTILITIES)

Comment:

ARB staff proposes to stop setting-aside allowances for the Voluntary Renewable Electricity (VRE) program in the post-2020 compliance periods. SMUD believes that ARB is acting prematurely on this issue, and supports a continued VRE set aside allocation post-2020.

SMUD relies on the VRE program to ensure promised carbon reductions to our popular Greenergy voluntary renewable program. SMUD suggested in one of the preliminary workshops last fall that ARB should be prepared to expand and extend the VRE program given the potential for new voluntary green pricing participation pursuant to SB 43 and more recently SB 350. It was just this year that the IOUs received permission from the CPUC to establish their voluntary green pricing programs pursuant to SB 43. Depending on the uptake of voluntary solar procurement under these new programs, similar programs now facilitated by SB 350 at POUs, and the ARB staff proposed changes allowing easier participation by distributed solar participants, the VRE allocation as it stands could be fully used by 2020. In SMUD's case, our Greenergy program is seeing a period of rapid expansion, with participation increasing by more than 50% in the last year or so.

ARB's contention that the VRE program is undersubscribed is based on only two years of program operation that occurred before the new programs and recent growth. ARB should await more information about how this expected growth impacts VRE program participation before determining that no further set aside is required. Otherwise, ARB runs the risk of stopping the growth of, and even causing declines in, these clean energy options as consumers realize their voluntary efforts are not providing GHG reductions as expected.

SMUD would support funding the VREP post-2020 at the same level as in 2020 using allowances that have remained unsold in the Cap-and-Trade auction for a period of two or three years. (SMUD)

Comment:

The following comments are related to ending allocations of allowances to the VRE Reserve Account in 2020.

1. VRE is an important driver of RE development in California.

Alongside state mandates like the Renewable Portfolio Standard (RPS) and carbon pricing programs like cap-and-trade, the VRE market has been a major driver of new clean energy development in the state, leading to more jobs and greater economic growth. The market leverages private, non-ratepayer funding to help speed the transition to RE sources, and it provides a pathway whereby the appetite for voluntary action can be channeled to in-state clean energy development.

Last year, around 520,000 megawatt-hours (MWh) of RE from California were used to supply Green-e certified voluntary sales, and California end-use customers purchased about 3.8 million MWh of certified VRE. Both of these numbers increased dramatically from 2014, by nearly 500% and over 50%, respectively. This shows strong demand for VRE in the state. It is also worth noting that Green-e certifies a majority but not the entirety of the voluntary market, which means that these represent conservative estimates of voluntary activity in the state. There are many large direct transactions,

several community choice aggregation programs, and a large amount of distributed generation for onsite consumption that are not included in these numbers. Other reports show that, at a national level, corporate buyers invested in more than three gigawatts (GW) of new RE capacity in 2015,³⁸⁷ and more than half of new U.S. utility-scale solar in 2016 will be built to serve voluntary customers.³⁸⁸³⁸⁹³⁹⁰

2. Voluntary means surplus to regulation.

Historically, VRE is not used to meet governmental targets, laws, or legal mandates. The voluntary market stands apart from and builds on compliance efforts. This enables the voluntary market to make an incremental difference often referred to as “regulatory surplus.” Also, many of the companies and individuals purchasing in California’s VRE market do so as part of their commitment to fight climate change. VRE buyers and investors therefore expect that voluntary generation will reduce emissions beyond the cap as a critical non-financial benefit. Our experience in the voluntary market has shown that emissions reductions beyond the cap, regulatory surplus, and moving the needle on climate change are significant drivers of voluntary demand.

Notwithstanding that avoided emissions due to RE decrease as the proportion of renewables increases over time, voluntary purchasers expect and deserve that whatever avoided emissions occur on the grid due to that generation will not just be making compliance cheaper and will be above and beyond what is required by law.

3. The VRE program (VREP) and Reserve Account³⁹¹ maintain the historical carbon emissions benefits for voluntary buyers that are otherwise removed by the cap and prevent a shift of compliance costs away from compliance entities toward voluntary purchasers.

We strongly support the preservation and continued use of the VRE Reserve Account mechanism and VRE allowance retirement to support the voluntary markets for RE in California. The 2016 ISOR accurately describes how cap-and-trade removes the ability of VRE to affect statewide emissions and how the VREP ensures that overall emissions reductions are achieved by VRE generation.³⁹² The VRE Reserve Account has wide support—when adopted in California, over 50 organizations publically supported such a policy, including energy companies, project developers, environmental and public health advocates, industry associations, academic institutions, and others. As shown in their

387 See <http://www.aweablog.org/the-rise-of-the-non-traditional-energy-buyer/>.

388 See <http://www.greentechmedia.com/articles/read/us-utility-scale-solar-market-fueled-bygrowth-beyondrenewable-portfolio-s>.

389 CCR § 95841.1

390 ISOR, p.53

³⁹¹ 17 CCR § 95841.1

³⁹² 2016 ISOR, p.53

comments to ARB,³⁹³ this is because the VRE Reserve Account restores regulatory surplus, allowing VRE purchases to reduce emissions beyond the cap, and letting California enjoy the benefits provided by such a market.

4. Allocations of VRE allowances should continue beyond 2020 to ensure that the VRE Reserve Account is not depleted, which would remove historical benefits or raise costs for those unable to obtain allowances through the Reserve Account, both of which could damage voluntary demand and limit the size and benefits of the voluntary market for California.

We recommend that allowances continue to be allocated to the VRE Reserve Account beyond 2020 in order to ensure that it remains effective.

According to the ISOR, Staff does not propose to allocate any additional allowances to the VRE Reserve Account “because requests for VRE retirement have been much lower than anticipated.”³⁹⁴ We submitted comments to ARB in April of this year outlining several reasons why past claims on Reserve Account may not be at all predictive of future demand.³⁹⁵

We suggested that there is likely a significant lack of awareness on the part of self-generating consumers (distributed generation facilities used for onsite consumption) and non-Green-e certified voluntary programs as to the VREP’s existence and/or benefits. We recommended additional outreach by ARB to the solar community and voluntary suppliers as well as consideration of an alternative, simplified procedure for allowance retirement in the VRE reserve account that does not require application.

We presented the launch of three large Green-e certified voluntary green pricing programs by the state’s investor-owned utilities (IOUs), as required by the California Public Utilities Commission (CPUC), as a significant source of new demand for VRE allowances. In January 2015, the CPUC directed the three largest IOUs in the state—Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company, which together cover nearly 80% of the state—to offer a Green-e Energy certified 100% RE option to their customers.³⁹⁶ As such, these

³⁹³ See the Previous Comments on VRE Set-aside Mechanisms listed in April 12, 2016 CRS Comments in response to the March 29, 2016 Workshop on Cap-and-Trade Regulation Post-2020 Emissions Caps and Allowance Allocation. Available online: http://resource-solutions.org/site/wp-content/uploads/2016/04/CRScomment_3-29Workshop_4-12-2016.pdf.

³⁹⁴ 2016 ISOR, p.54

³⁹⁵ April 12, 2016. CRS Comments in response to the March 29, 2016 Workshop on Cap-and-Trade Regulation Post-2020 Emissions Caps and Allowance Allocation. Available online: http://resource-solutions.org/site/wp-content/uploads/2016/04/CRScomment_3-29Workshop_4-12-2016.pdf

³⁹⁶ CPUC. Decision 15-01-051 January 29, 2015. Decision Approving Green Tariff Shared Renewables Program for San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company pursuant to Senate Bill 43. Available online: <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M146/K250/146250314.PDF>.

products will need to comply with Green-e requirements that participants sourcing from supply located in California or directly delivering to California must retire allowances through the VREP or retire California-eligible allowances independently on behalf of certified sales to voluntary purchasers.³⁹⁷ We provided a back-of-the-envelope calculation of potential demand for VRE allowances from these three voluntary programs alone— approximately 562,392 metric tons annually, representing two-thirds of the total VRE reserve account in 2020.³⁹⁸ We added this to current subscriptions to arrive at a conservative floor of what will be needed in the VRE reserve account annually: approximately 676,000 allowances.³⁹⁹ This does not include potential additional demand coming from the expansion of Community Choice Aggregation (CCA) programs in California delivering RE in excess of the RPS, increased use amongst onsite solar customers, or increased demand from commercial and industrial customers.

ARB has not conducted any analysis of future demand for VRE allowance retirement. Due to the potential loss of environmental benefit to the state should the VRE Reserve Account be depleted, and the minimal cost of continuing allocation (see further below), only an in-depth analysis of future voluntary demand showing that it can be met without future allocations could support a decision not to continue allocation.

Once the Reserve Account is depleted, VRE is no longer surplus to regulation and it no longer has an avoided emissions benefit. VRE will simply reduce emissions to free up allowances and lower the costs of compliance for regulated entities. This represents a shift in compliance costs away from regulated entities and onto those taking voluntary action. Alternatively, VRE purchasers would be forced to pay the price on carbon (i.e. buy and retire an allowance) in order to achieve regulatory surplus and restore their emissions benefits, which represents a significant increase in the price of historical VRE.

Without explicit recognition of the emissions reductions from the voluntary market, a principal driver of VRE investments may be lost. Voluntary demand for RE may suffer due to the loss of regulatory surplus and the change in benefits, from VRE that impacts statewide emissions to VRE that lowers the price of carbon. Or demand may suffer due to the dramatic increase in price of VRE that includes these historical benefits. Should demand suffer due to either of these outcomes, both the benefits of VRE beyond the cap and the benefits of VRE within cap-and-trade may disappear.

5. ARB Staff's responses and conclusions in 2011 Final Statement of Reasons (FSOR) related to ceasing allocations to the VRE Reserve Account after 2020 fail to

³⁹⁷ See Section A.5, p.30-33, of the Green-e Energy National Standard v2.8: <http://www.greene.org/docs/energy/Green-eEnergyNationalStandard.pdf>.

³⁹⁸ See the VRE reserve account annual allocation here: <http://www.arb.ca.gov/cc/capandtrade/guidance/chapter7.pdf>

³⁹⁹ 113,489 allowances retired by CARB through the VREP for RY 2014.

acknowledge the value of VRE. The VREP program should not be transitional because voluntary buyers want to reduce beyond the cap and may no longer purchase or invest otherwise, resulting in a loss of emissions reductions for the state.

At several points in the 2011 FSOR, Staff describes the VREP as a “transitional” strategy or program.⁴⁰⁰ Staff explains that it expects voluntary use of renewables to continue to increase regardless of whether it reduces the cap because “as allowance prices rise, and assuming that the cost of renewable electricity will continue to fall, electricity end-users will have increasing economic incentives to purchase electricity that is not subject to a carbon price, including voluntary renewables.”⁴⁰¹ In other words, they “expect renewable electricity and other low GHG-emitting generation to become the best economic choice for many businesses and homeowners as carbon costs rise.”⁴⁰² It explains further that “Our goal is to transition to 100 percent auction. To that end, it will be necessary for the voluntary sector to eventually participate in the program by registering as a voluntary associated entity, and to purchase and retire allowances on behalf of the voluntary contributions.”⁴⁰³

ARB Staff fails to recognize the value of VRE as a separate market and source of emissions reductions. Staff envisions that the price on carbon will work to incentivize low-emitting technology as it makes emissions more expensive, but that all emissions reductions will be captured under the cap. In that way, the cap is a ceiling for both emissions and emissions reductions. Staff argues that VRE will continue on the basis of this economic incentive. But since the voluntary market is currently reducing beyond the cap, what they are actually saying is that there is no need for a voluntary market once there is a price on carbon. We disagree. Our experience is that there will always be those that want to reduce beyond what is required by law. The state can and should facilitate that activity, but at the very least it should not harm or hinder it by forcing VRE purchasers to pay the price of carbon that should be borne by emitters. This is not only unfair, but it will likely disincentivize voluntary reductions. Continuing allocations to the VRE set-aside will prevent cap-and-trade from becoming the ceiling for reductions.

6. The allowance price effect of continuing allowance allocations to VREP is negligible. But there is great benefit to the voluntary market and to California.

Continuing allocations to the VRE Reserve Account is cost neutral for compliance entities: the decrease in supply of allowances and corresponding increase in price is offset by the decrease in demand for allowances due to reductions from voluntary renewable energy and corresponding decrease in price. But there is great benefit to the voluntary market and the cost of VRE. Likewise, discontinuing allocations to the set-aside is benefit neutral for compliance entities: the increase in supply of allowances that are no longer being set aside and corresponding decrease in price is offset by the

⁴⁰⁰ See 2011 FSOR, p.621, 1546, 1552, and 2123

⁴⁰¹ 2011 FSOR, p.621

⁴⁰² 2011 FSOR, p.1546

⁴⁰³ 2011 FSOR, p.2123

increase in demand for allowances as VRE no longer pays for reductions and those costs shift to compliance entities, increasing the price. But there is great cost to the voluntary market.

The effect on allowances prices is illustrated graphically below.⁴⁰⁴



7. Continuing allocations of VRE allowances will keep voluntary, private investment in the state.

The VRE Reserve Account provides a pathway whereby the appetite for voluntary action can be channeled to clean energy development in California, and avoids a situation whereby the willingness to invest in voluntary action is diverted to out-of-state projects. If the Reserve Account is depleted, the reduction in benefits or the additional cost of allowance retirement to the voluntary purchaser may reduce demand and preclude certified sales from generation in the state. Voluntary buyers in California would instead procure their certified renewable energy from outside of the state in the future. Continuing to allocate to the VRE Reserve Account will ensure that this demand can be met by resources in the state—allowing California the opportunity to maintain the

⁴⁰⁴ This was initially presented to ARB in a June 7, 2010 Coalition letter to Kevin Kennedy, CARB Office of Climate Change on the issue of off-the-top treatment of voluntary renewable energy purchases. Available online: http://resource-solutions.org/site/wp-content/uploads/2015/08/CRS_on_allocation_7_7_2010.pdf.

private investment dollars that may otherwise go elsewhere—and this could prevent a loss of revenue from voluntary purchasers for in-state generation.

In 2015, California customers demanded 3.8 million MWh of Green-e certified VRE that is surplus to regulation. This is demand that could be met with in state generation, if allocations continue. Around 520,000 MWh from California was used to supply Green-e certified sales. This is supply that reduced emissions beyond the cap, from facilities that can continue to see extra revenue from voluntary purchasers, if allocations continue. That revenue could be lost if allocations cease.

8. Continuing allocations of VRE allowances will prevent a loss of emissions reductions in the state.

VRE is no different from RPS RE in terms of its effect on the grid, and both are recognized as increasingly important tools to reduce emissions in the state. The VRE Reserve Account allows consumer preferences for RE to drive more reductions than those achieved by policy mechanisms alone. The increased clean energy development puts the state in a better position to meet our more ambitious long-term goals. Should the VRE Reserve Account become depleted, the capped level becomes the ceiling for emissions reductions.

Ultimately, the state has little if anything to gain and all of the benefits of VRE to lose by discontinuing allocations of VRE allowances after 2020, both environmentally and economically. There is no significant cost savings to compliance entities. There are more allowances (emissions) in the market. There is a risk of damaging voluntary demand, either as VRE is brought under the cap, in which case there is no advantage in terms of capped emissions, or as the cost of VRE that reduces statewide emissions increases, in which case there is no benefit to statewide emissions. Conversely, continuing allocations to the VRE Reserve Account imposes little if any cost, maintains voluntary demand and private investment in the state, and reduces emissions for the state. (CRS)

Comment:

Voluntary Renewable Energy Allowance (VRE) Set-Aside Program

3Degrees strongly supports the preservation and continuation of the Voluntary Renewable Electricity (VRE) set-aside (Section 95841.1) indefinitely. The VRE reserve account is critically important to California's voluntary renewable energy market because it enables customers without a compliance obligation to promote new renewable energy projects and to reduce carbon emissions in California in excess of AB 32's cap.

The ability to decrease carbon emissions beyond what is required by regulation is a primary benefit associated with purchasing renewable energy for voluntary customers. The existence of the cap on carbon emissions in California ensures that compliance entities in California keep emissions below the cap. In order to credibly claim to

decrease emissions in California, voluntary customers need to be able to demonstrate emissions reductions above and beyond what the existing cap already requires. By enabling consumers to retire allowances in a cost effective manner, the VRE set aside enables a California voluntary renewable energy consumer to credibly claim to have decreased carbon emissions in California as a result of their voluntary renewable energy purchase.

If the VRE set aside were to be terminated in 2020, or at any point in the future, California voluntary renewable energy customers would no longer be able to claim to have avoided carbon emissions with their REC purchase. Instead these avoided carbon emissions would benefit compliance entities who will not be responsible for emissions associated with the VRE generation and will have the same number of allowances to purchase for compliance as they would have in the absence of the VRE generation.

In the absence of the VRE set aside, if the California voluntary consumer seeks to maintain the avoided carbon benefits from its purchase, it would need to go into the allowance market and purchase an allowance for retirement. This action would cause the price of a voluntary REC in California to greatly increase. Based on a current market price for a CA Allowance, a REC that is paired with an Allowance (so that it contains all of the environmental attributes) would see an increase in cost in the neighborhood of \$5.00 to \$6.50 per REC (cost of Allowance multiplied by 0.428 MtCO₂e/MWh). This type of negative pricing impact would decrease the purchases of California REC's and could drive voluntary REC buyers to other states' markets or cause voluntary buyers to exit the REC market entirely.

In addition to losing out on the avoided carbon benefits associated with a vibrant voluntary REC market, California would risk losing out on the economic and other pollution avoidance benefits associated with California based renewable energy projects at an inopportune time. The voluntary REC market in California is large, and growing. In 2015, around 520,000 megawatthours MWh of renewable energy from California were used to supply Green-e certified voluntary sales, and California end-use customers purchased about 3.8 million MWh. Both of these numbers increased dramatically from 2014, by nearly 500% and over 50%, respectively.

Through Senate Bill 43, California's large investor owned utilities are required to operate Green Tariff Shared Renewables Programs. These programs are just getting started and will provide additional voluntary renewable energy customers in California the opportunity to avoid carbon emissions associated with their energy usage. In order for these programs to promote the entire benefits associated with them, they need to be able to demonstrate avoided carbon emissions. This is best achieved through the integration of these programs into the VRE set aside program and retiring allowances associated with those programs.

The voluntary renewable energy market and specifically voluntary REC demand drives a substantial proportion of renewable build in California. ARB should ensure that

California continues to see the benefits of this production through the continuation of the VRE set aside program indefinitely.

Sending a clear signal that the VRE set aside will continue indefinitely will offer protection to existing and future voluntary renewable energy markets. This does not create a new compliance instrument, does not conflict with current California RPS statute, and does not require that ARB create new systems or processes. Furthermore, it will provide a positive market signal and promote the long term growth in the California renewable energy market. (3DEGREES)

Comment:

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....

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 MTCO₂e/MWh to a value that more accurately represents avoided emissions from voluntary renewable electricity generation in the 2020-2030 time period. (PG&E)

Comment:

ARB Staff have proposed keeping the VRE program and amending eligibility, which SDG&E supports. However, the Staff proposes to remove the funding of allowances for the VRE Program post-2020 due to lack of utilization of the program to date. The Board should consider providing allowances post-2020 as utilities are ramping up Green Tariff Shared Renewables (GTSR) programs. These programs require Green-e certification for compliance.

Maintaining Green-e certification in California in turn requires retiring allowances in the C&T program. These GTSR programs are currently enrolling customers, and participation will result in ongoing demand for VRE program allowances through their 20-year statutory program duration. In addition to IOU programs, there are also Green-e certified CCA programs, and POU voluntary renewable programs with similar requirements to reduce greenhouse gases by retiring allowances.

The funding of allowances for the VRE program could be supplied after the fact post-2020, so that other sectors are not prematurely restricted. Further, the supply could come from the supply of unsold allowances. Finally, SDG&E would suggest lowering the assigned emissions factor of the VRE program from 0.428 MTCO₂e/MWh to approximately 0.3 MTCO₂e/MWh to accommodate increased participation without proportionally increasing the overall number of allowances needed for retirement. The 0.3 MTCO₂e/MWh figure represents the avoided portfolio emissions on a procurement basis and so more accurately portrays the GHG benefits of the program.

SDG&E Recommendation: The Board should amend the VRE program in section 95841.1 as follows:

Change the factor in section 95841.1 (c) to convert MWh to MT from EF_{unspecified} to 0.3 MT CO₂e/MWh.

Add a new section 95841.1(d) supporting funding VRE program, possibly on an after-the-fact basis, initially beginning funding with unsold allowances. (SDGE)

Comment:

But as it seems likely that participation in the VRE program will increase under the expanded guidelines, we recommend ARB include a provision to periodically assess the VRE reserve account and transfer additional allowances into it as needed to prevent it from becoming depleted.⁴⁰⁵ (NRDC)

Response: Many commenters support the continued retirement of allowances through the VRE Program, but oppose the lack of allocation of post-2020 allowances to the VRE Account, in large part because of the expansion of renewables programs. ARB staff declines to make changes to increase the set aside pool of allowances for the VRE. While staff acknowledges that these programs may result in increased demand for retirement of VRE Program allowances, the historical lack of requests for retirement, the significant amount of VRE allowances still remaining, uncertainty over future requests, and the reduction in the annual allowance budgets framework proposed in this rulemaking for the post-2020 period, necessitate caution in the set aside of additional allowances that would otherwise be available for auction. Staff commits to monitoring the volume of allowances available for retirement in the

⁴⁰⁵ Up until a ceiling is reached; e.g., the same percentage of allowances that were transferred to the VRE reserve account out of the pre-2020 cap.

VRE Account and the annual requests for retirement, and considering allocating more allowances to the VRE Account from post-2020 vintages if the supply of VRE allowances is less than the demand for them.

Broadening VRE Eligibility Requirements

D-4.2. Comment:

Voluntary Renewable Energy (VRE) Program

We support the proposal to expand the eligibility requirements of the Voluntary Renewable Energy (VRE) program, which provides a mechanism to ensure that overall emissions reductions are still achieved by voluntary renewable electricity generation by retiring allowances taken “off the top” of the cap. As staff notes, to be eligible for allowance retirement currently, renewable generation must come from either a generator that is RPS-certified by the California Energy Commission (CEC) or meet the CEC’s guidelines for California’s Solar Initiative (CSI), for which participants must also document that the generator received a CSI incentive.⁴⁰⁶ Because several EDUs have exhausted their CSI funds, however, new solar generation projects cannot demonstrate that they received a CSI incentive and therefore are ineligible for the VRE program. Partly as a result, requests for VRE retirement have been much lower than anticipated.

We agree it is appropriate then to allow, as proposed, solar systems that meet EDU installation requirements and which are similar to the CSI requirements to be eligible for VRE participation. (NRDC)

Response: Thank you for the support.

E. OFFSETS AND OFFSET PROGRAM IMPLEMENTATION

E-1. Availability and Usage of Offsets

Offset Supply

E-1.1. Multiple Comments:

OFFSETS ARE ESSENTIAL

CalChamber maintains its position that a robust offset program is a key cost containment mechanism. A robust supply of offsets are required in order to reduce program costs. Therefore, a consideration of offset protocols is encouraged. Expanding the allowable use of offsets is a sound policy choice. Numerous economic studies have shown, including CARB’s own analysis, that offsets are the best market-based alternative to reduce costs and limit leakage. Expanded use of offsets is consistent with CARB’s statutory obligation to achieve the maximum technologically feasible and cost

⁴⁰⁶ ISOR at 53-54.

effective GHG emissions reductions. Offsets are a proven and cost-effective means of meeting AB 32 compliance obligations. (CALCHAMBERCOMMERCE)

Comment:

Also, we do encourage the Board to develop a more robust offset program. We feel that that's a great way to achieve cost containment within the program. (CALCHAMBER2)

Comment:

Finally, a focus on cost containment leads JUG members to call for increased efforts to encourage offset supply, ensure ability to use offsets up to the offset limit... All of these proposals will help control the costs borne by utility customers while enabling Cap-and-Trade to deliver the emission reductions necessary to achieve the state's longterm climate goals. When viewed as a key element, JUG members believe cost containment can increase the effectiveness of California's Cap-and-Trade program and demonstrate leadership to jurisdictions considering their own climate policies. (JOINTUTILITIES)

Comment:

SMUD also supports the comments filed by the Joint Utility Group, covering the following key themes:

- It is important that functional cost containment continue to be an important element of market design...

(SMUD)

Comment:

Offsets Must Be Expanded to Capture Additional Cost Containment and Emissions Reduction Benefits

Offsets are a proven and cost-effective means of meeting AB 32 compliance obligations. They are also an effective means of achieving significant GHG emissions reductions in other jurisdictions which lack GHG regulatory programs. Expanded and expedited use of offsets is consistent with ARB's statutory obligation to achieve the maximum technologically feasible and cost-effective GHG emissions reductions. (CCPC)

Comment:

The ARB Should Encourage a Robust Offset Market.

The 8% offset usage limit is an important aspect of the Cap-and-Trade program. Offsets allow for investments in cost-effective emissions reduction and create a needed price signal for new innovative GHG emissions reduction technologies. The usage of offsets also serves as an important cost containment measure in the event that an additional supply of compliance instruments is needed by obligated entities. The ARB should

retain the 8% offset usage limit and continue to evaluate new opportunities for offset protocols, such as the REDD offset program. (TURLOCKID)

Comment:

4.1 Compliance Offset Protocols (Regulation, Subarticle 13)

The production of offset credits is currently below the 8% limit of emissions to cover emitters subject to the agreements. Adapting current protocols and developing new ones would maximize the number of offset available, in addition to encouraging the development of green technologies and additional reductions in GHG.

For example, developing a protocol to promote reductions in GHG in the maritime transport industry would encourage reductions not covered by the system, but useful for achieving targets in Québec and California.

A collaborative effort with players in the market would make it possible to identify protocols that reflect the needs and reality of the market.

Gaz Métro's recommendations

Gaz Métro recommends continuing to work with market players and representatives from the Québec and Ontario governments to develop protocols and modify current protocols in order to significantly increase the number of offset credits produced in California and elsewhere in the United States. (GAZMETRO)

Comment:

Ahtna supports California's commitment to addressing climate change. Forest offset projects made possible by the Cap-and-Trade Program enable millions of tons of carbon to be sequestered while also providing critical co-benefits to our shareholders in rural Alaska, allowing them to sustain their traditional culture and way-of-life and protect the environment that they have called home for thousands of years. As a general matter, we therefore support the Offset Program and we believe that most of the currently proposed amendments will improve the Regulation and the Program. (AHTNA)

Response: Commenters are expressing support for the offsets program in general and for maintaining the quantitative usage limit at 8%. Commenters are also requesting the expansion of existing protocols and the addition of new offset protocols to increase offset supply. Additional offset protocols are outside the scope of this rulemaking; therefore, no response is required. However, ARB staff is committed to evaluating additional offset types to ensure sufficient offset supply and working with stakeholders to increase participation in the existing protocols. With respect to the comment expressing interest in REDD offsets, please see response to 45-day comment I-4.1.

Quantitative Usage Limit

E-1.2. Comment:

4.2 Eight percent (8%) limit on the number of offset credits that covered entities may surrender to meet their compliance obligations (Regulation, Subarticle 7, § 95854)

According to the current Regulation, the use of offset credits by an emitter subject to the system is limited to 8% of the total compliance obligation. The 8% limit could be increased to 15% to encourage promoters to complete offset credit programs and allow for the wider use of offset credits as a compliance tool.

Since the price of offset credits is lower than allowances, wider access would also reduce the offset cost of emissions.

Gaz Métro's recommendations

Gaz Métro recommends that the 8% limit for using offset credits be increased to 15%. (GAZMETRO)

Response: The commenter proposes expanding the quantitative usage limit from eight to 15 percent. ARB staff did not propose revisions to the quantitative usage limit for offsets as part of this rulemaking; therefore, this comment is outside the scope of this rulemaking and no response is required.

E-1.3. Comment:

Exempt from the offset limit any offsets that provide in-state ancillary environmental benefits similar to actual reductions at capped sector facilities, by offering more of the following benefits: 1) a direct reduction or avoidance of any criteria air pollutant in California; 2) a direct reduction or avoidance any impacts on water quality in California; 3) a direct alleviation of a local nuisance within California associated with the emission of odors; 4) direct environmental improvements to land uses and practices in California's agricultural sector; 5) direct environmental improvements to California's natural forest resources and other natural resources; and/or 6) a direct reduction of the need for mitigation of the impacts within California of rising global greenhouse gas emissions. (SMUD)

Response: The commenter is requesting that in-state offset credits be exempted from the offset quantitative usage limit. ARB staff did not propose revisions to the quantitative usage limit for offsets as part of this rulemaking; therefore, this comment is outside the scope of this rulemaking and no response is required.

E-1.4. Comment:

Finding a way to apply the 8% offset limit to facilitate full use of offsets up to the limit. It is now clear from the record in the first compliance period that the market could not or certainly did not fully utilize offsets - only 4.5% of the compliance instruments surrendered were offsets, well below the 8% limit. As SMUD and other stakeholders

have noted, greater use of offsets will help to contain the costs of obligated entities under the Cap-and-Trade Program. SMUD suggests that the ARB either: 1) allow entity's to "carry over" any unused portion of the offset limit across compliance periods; 2) spread unused amounts over the broader market so that the limit is fully used; or 3) establish an "offset-limit bank" in which unused portions of the 8% limit could be offered up as the APCR is accessed - essentially extending the concept of holding back some compliance instruments to be released when/if prices get to the APCR level. (SMUD)

Response: The commenter proposes several options to allow unused portions of the quantitative usage limit to be used in the future. ARB staff did not propose changes to provisions related to the quantitative usage limit for offsets as part of this rulemaking; therefore, this comment is outside the scope of this rulemaking and does not require a response.

E-2. Opposition to Offsets

E-2.1. Multiple Comments:

Eliminate offsets. Actions and investments taken by industry to reduce emissions need to be reinvested in the communities where the emissions have occurred. Any benefits from greenhouse gas reduction measures must affect California first. (EJAC)

Comment:

I wanted to highlight the specific impacts of using offsets. And I specifically wanted to look at the electricity sector. You're going to hear from other people about the refineries in California, and in the communities where we organize. The electricity sector is among the top 10 users of offsets. And that includes Calpine, that includes Southern California Edison, that includes NRG, for their existing electricity generation units for the power plants that are keeping our lights on today. SMUD keeps our lights on here. But for the places where many of our members live, we're seeing more and more reliance on peaking power plants as we are integrating renewables into our grid. And those peakers tend to be the most polluting sources of electricity, and they are not the best way to smooth out the grid. There is better technology. The only reason that it is not in use today is because it is more economical to keep running the dirty peakers. And that is what cap and trade allows to happen. And if you do not institute technology forcing regulation, it will continue to happen. (COMMBETTENV)

Comment:

Pollution trading lets big polluters, like Chevron, which is actually the largest point source of pollution in the area, off the hook. It lets them buy cheap credits or bank credits they get for free, so they can pollute instead of cleaning up themselves. Studies have found that children in Richmond are twice as likely to have asthma as compared to children in the rest of California. In addition, the city has also -- the city also has higher rates of low birth weight -- lower -- low birth-weight babies, cancer, and respiratory illnesses. Chevron is also the

single largest user of offsets. And this is a problem considering the tremendous health implications of living and working near a refinery. (COMMBETTENV2)

Comment:

In low-income communities and communities of color, we know one truth about cap and trade, it does not work and it is not working for us. The reductions that we see of greenhouse gas emissions come from offsets outside the State, and in some cases, outside of the country. (CENTRACEPOENV3)

Comment:

Oil refineries, power plants, and oil productions, and other polluters concentrated in communities of color, and low-income communities have bought offsets like planting forests out of State instead of cleaning up in California. (LEADERCOUNSEL)

Comment:

The EJAC expects to see the largest proportion of reductions of greenhouse gases take place in California in the future. ARB must prioritize actions and investments in California EJ communities before looking at other Californian communities or outside of California. (EJAC)

Comment:

California's Cap-and-Trade Program Allows for the Use of Offsets to Exceed the Amount of Targeted Reductions.

Like the current cap-and-trade regulation, the Proposed Amendments would allow offset credits to be used to satisfy up to 8 percent of the greenhouse gas compliance obligation of covered entities (i.e., regulated emission sources). As detailed in an analysis released last week by Lara Cushing, et al., offset credits worth more than 12 million tons CO₂eq were utilized to meet compliance obligations in the first compliance period.⁴⁰⁷ These offsets represent 4.4 percent of the total compliance obligation of all regulated companies and over four times the targeted greenhouse gas reduction in 2013 to 2014.⁴⁰⁸

Seventy-six percent of the offset credits used to date were generated by out-of-state projects. Thus, rather than achieving reductions at the emissions sources, where California communities might benefit from reductions in associated co-pollutants, those reductions were produced via financial transfers from offset projects outside of California. Furthermore, for the 46% of offset credits that came from the destruction of ozone-depleting substances—primarily industrial refrigerants, previously captured and

⁴⁰⁷ Lara J. Cushing, Lara J. Cushing, Madeline Wander, Rachel Morello-Frosch, Manuel Pastor, Allen Zhu, and James Sadd, 2016, A Preliminary Environmental Equity Assessment of California's Cap and Trade Program, at 9. Available at http://dornsife.usc.edu/PERE/enviro_equity_CA_cap_trade.

⁴⁰⁸ *Id.* at 8.

stored in containers—no co-benefits were felt at the actual project site outside of California, either. (CBD)

Response: Commenters are proposing the elimination of offsets from the Cap-and-Trade Program. ARB staff has not proposed revisions to, or elimination of, the quantitative offset usage limit as part of this rulemaking. Comments related to elimination of offsets are outside the scope of this rulemaking; therefore, no response is required. Notwithstanding this, and contrary to some of the comments, at this time ARB offset credits can only be generated from projects within the U.S. Additionally, unlike measures for reducing criteria and toxic emissions (which have direct regional/local benefits), the location of GHG reductions is not relevant from a climate perspective, because global warming is a global issue, and therefore GHG reductions benefit the global climate and unlike criteria and toxics emissions, GHGs do not pose a localized health risk.

When developing the existing eight percent quantitative usage limit, the initial rulemaking documentation in 2010 clarifies that the limit was chosen to balance the use of offset credits as “an important cost-containment mechanism, while also encouraging deployment of greenhouse gas-reduction technologies in uncapped sectors. Table 26 of the Updated Economic Evaluation of California’s Climate Change Scoping Plan demonstrates that the impacts to the state economy of a cap-and-trade program that does not allow for the use of offsets are substantially greater than a program that allows for the use of offsets.” (2011 FSOR, at p. 549). Although not part of this rulemaking, ARB staff would conduct a similar type of economic analysis as was done for the 2008 Scoping Plan regarding any change to the offsets quantitative usage limit to understand the impacts of such a change on cost-containment.

Furthermore, many offset projects are located in California, and directly result in benefits to California. A significant portion of the ozone-depleting substances destroyed out-of-state are recovered from communities throughout California, resulting in direct emissions reductions in California. Additionally, ARB has received similar concerns as those raised by the commenters throughout the development of the 2013-2020 program regarding the desire to limit the potential for out-of-state offset projects vis-à-vis in-state projects.⁴⁰⁹ With the recent passage of AB 398, ARB staff will initiate a rulemaking process to implement the requirements of AB 398 for the post-2020 Cap-and-Trade Program, including changing the quantitative usage limit for offset credits from 8% in the 2013-2020 time frame, to 4% from 2021-2025 and 6% in 2026-2030.

Finally, with respect to comments asserting that the offsets program means reductions are not occurring within California, as indicated in the annually

⁴⁰⁹ See for example second 15-day comments F-3 and M-1 of the 2011 FSOR <https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>, and Attachment D to the 2010 ISOR, <https://www.arb.ca.gov/regact/2010/capandtrade10/capv2appd.pdf> (at p. D-46).

reported and verified GHG emissions data, GHG emissions have been declining statewide since the adoption of the Cap-and-Trade Program. Indeed, as the Cap-and-Trade Program covers 85 percent of the GHG emissions in the State and given that the emissions cap declines every year, there necessarily are direct emissions reductions from sources subject to the Regulation. See also responses to 45-day comments K-1.2 and K-1.5.

E-3. General Offset Support

E-3.1. Comment:

Offsets, including sector-based forestry protocols, provide a critical cost containment function to the Cap-and-Trade program. Cost containment improves environmental outcomes and helps protect Californian businesses and residents, while helping to ensure the success of Cap-and-Trade as a model program.

Offsets achieve "additional" GHG emissions reductions outside of the cap, meaning that offsets come from sectors not directly regulated under AB 32. Besides bringing more businesses and economic activity into AB 32, offsets provide critical benefits to California. Offsets must be real, permanent, quantifiable, verifiable, enforceable, and provide additional emissions reductions that can lessen the economic burden on California businesses, workers, and residents. Additionally, offsets help demonstrate California's global leadership and prove the success of a well-designed program, thereby influencing regions that may not be currently considering their own actions. Global change is needed to avert climate crisis. Commitment by a State and economy as large as California will not be enough on its own to affect the global concentration of GHG emissions. The California program will only be successful if it can catalyze global change and prompt others to develop similar programs. (CCEEB)

Response: ARB appreciates the commenter's support.

E-3.2. Comment:

Early-Action

Portions of the amendments are proposing to remove many of the references to the Early-action offsets program now that the deadline for registering early-action projects has passed (or in the case of rice-cultivation will soon pass). CODA would like to extend its thanks to ARB for establishing and implementing the process for recognizing offsets from early-action projects and thus rewarding actions taken by first-movers in the offsets space. CODA also appreciates the efforts expended by ARB staff to work through the instances where further clarification and guidance was required to process early-action projects. (CODA)

Response: ARB appreciates the commenter's support.

E-3.3. Comment:

Sealaska strongly supports California's commitment to addressing climate change. Northern communities are experiencing the impacts of climate change more acutely than many others. Sealaska supports extending the Cap-and-Trade Program beyond 2020, and specifically the forest offset program. It sequesters carbon, which benefits the planet by locking up GHGs. It helps to contain costs for all in California indirectly, and it provides economic and environmental co-benefits. Alaska's rural villages are some of the most economically depressed in the country. Sealaska's forest project will bring economic developments to the native peoples of South East Alaska. The project also will preserve and protect large forests, including some that were selected because they border sensitive marine habitats and thus will help to protect those as well (SEALASKA3)

Response: ARB appreciates the commenter's support.

E-4. General Offsets

Intentional Reversal

E-4.1. Multiple Comments:

Adding Overestimations Due to the Use of Approved Growth Models to the Definition of Intentional Reversal is Inappropriate.

ARB's proposed definition of "intentional reversal" appears to alter what was previously the touchstone of determining the status of a reversal – that is, whether the reversal was "caused by a forest owner's negligence, gross negligence, or willful intent" CTR Section 95802(a)190. A forest owner that so causes a reversal is, appropriately in our view, responsible for replacing the requisite amount of ARBOCs. Id. at 95983(c)(3). However, the proposed definition of "intentional reversal" now includes those reversals that are "caused by approved growth models overestimating carbon stocks." Proposed CTR Section 95802(a). It is difficult to understand how using a growth model approved by ARB is tantamount to "negligence, gross negligence, or willful intent." It would be far more appropriate to treat as unintentional any reversal due to an overestimation of carbon stocks that results from the use of an approved growth model and not negligence or worse. Such an overestimation may not be the result of an Act of God such as disease and wildfires, the examples cited in the current definition of "unintentional reversal," but they are the result of well-intentioned human acts that cause a reversal just as the intentional setting of a back burn, the exception cited in the definition of "intentional reversal." In both instances, the reversals are the result of acts by persons other than the forest owner. The forest owner should not be held responsible for the acts of others in positions of authority as if she was guilty of negligence, gross negligence, or willful intent. In short, overestimations that result from the use of an approved growth model should be treated as unintentional and not intentional reversals. We therefore respectfully suggest the following modifications to

the proposed amendments to CTR Section 95802(a) (italicized words are those already proposed by ARB; our proposed additions are underlined):

“Intentional Reversal” means any reversal, except as provided below, which is caused by a forest owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the offset project boundary, ~~or caused by approved growth models overestimating carbon stocks.~~ A reversal caused by an intentional back burn set by, or at the request of, a local, state, or federal fire protection agency for the purpose of protecting forestlands from an advancing wildfire that began on another property through no negligence, gross negligence, or willful misconduct of the forest owner is not considered an intentional reversal but, rather, an unintentional reversal. *Receiving Adverse Offset Verification Statements on two consecutive offset verifications after the end of the final crediting period will be considered an intentional reversal.*

“Unintentional Reversal” means any reversal, including wildfires or disease that is not the result of the forest owner's negligence, gross negligence, or willful intent, including a reversal caused by approved growth models overestimating carbon stocks. *In the case of a wildfire, only trees identified as dead or dying, in the post-event inventory, as a result of the fire will be removed from the project's inventory and compensated from the Forest Buffer Account minus any salvage harvest accounted for under long-term storage.*

We Welcome ARB's Proposed Amendment Extending the Timeline for Conducting a Post-Unintentional Reversal Carbon Stock Estimate.

Because it is not hard to foresee a situation in which it would be necessary, we welcome ARB's proposal to expand the timeline to complete a post-unintentional reversal carbon stock estimate. ARB's proposed section 95983(b)(1) will allow 23 months for such a carbon stock estimate to be conducted. Depending on the acreage involved in such a reversal, providing a complete and accurate carbon estimate may take a significant amount of time. This is especially true for many of the forest projects in Alaska where the acreages are vast. We also welcome as reasonable and practicable ARB's proposal to toll the requirement of submitting an offset project data report while this carbon estimate is being completed.(SEALASKA, SEALASKA2)

Comment:

5. The Proposed Changes to the Definition of Intentional Reversal is Not Appropriate.

ARB's proposed definition of “intentional reversal” changes what determines the status of a reversal — that is, whether the reversal was “caused by a forest owner's negligence, gross negligence, or willful intent.. . .” CTR Section 95802(a)190. A forest owner that so causes a reversal is responsible for replacing the requisite amount of ARBOCs. *Id.* at 95983(c)(3). The proposed definition of “intentional reversal” would

include reversals “caused by approved growth models overestimating carbon stocks.” Proposed CTR Section 95802(a). Using a growth model approved by ARB should not be the same as “negligence, gross negligence, or willful intent.” Instead, any reversal due to an overestimation of carbon stocks caused by the use of an approved growth model should be treated as an unintentional reversal. They would be the result of a third party — the persons that developed the growth model and the ARB officials that approved it and not the forest owner. The forest owner should not be held responsible for the acts of others as if she was guilty of negligence, gross negligence, or willful intent.

In Ahtna’s case, the chance of a reversal due to overestimation is a massive risk, significantly impacting the value of a project. Overestimation in a small forest project may be minor. But because Ahtna’s forest project could account for millions of tons of sequestered carbon, even a relatively small overestimate could lead to costly, and unfair, forest owner liability. On the other hand, underestimation, which diminishes the perceived value of the project, is not a solution. Ahtna’s earnest and honest attempts to accurately estimate carbon stocks by applying an approved growth model should not be punished by a reduction in value merely because the approved model fails to accurately predict the future. (AHTNA)

Response: The commenters disagree with the proposed revision in section 95802 to the definition of “Intentional Reversal,” which is changed to include forest offset project reversals caused by approved growth models overestimating carbon stocks. ARB staff believes that modeling errors should not be categorized as unintentional reversals similar to forest fires and other natural acts, which are outside of the offset project operator’s control. The project operator is responsible of selecting the appropriate model as well as the correct calibration and use of the model. Since so much of the model is within the control of the project operator, the project operator bears the ultimate responsibility for the model’s correct use.

ARB appreciates the support for increasing the time to submit a verified estimate of a reversal from 12 months to 23 months. Given that it can take the full eleven months allowed after a reporting period to complete a standard verification, ARB staff determined that the existing 12 month deadline was insufficient to salvage harvest, inventory, report and verify the reversal, especially given that forested areas are often inaccessible for significant portions of the year.

Buyer Liability

E-4.2. Multiple Comments:

Streamlining of offset policy while maintaining offset integrity that allows compliance entities (particularly smaller entities) to access offsets up to their current limit. For example, the buyer liability aspect of most offsets imposes a market risk that prevents many from considering the offset alternative, even with market-insured “golden” offsets.

SMUD encourages ARB once again to move away from buyer liability in current and future offset protocols. (SMUD)

Comment:

The purchase of existing offset projects has not taken-off as originally anticipated by ARB or the offset community. There are a number of issues discouraging the purchase of offsets. Among them are concerns about buyers' liability over the life of an offset project. Liability of the quality and duration of an offset project is left with the buyer unless the risk is addressed contractually. Only a small number of sellers provide assurances and contractual contingencies. The majority of offset projects require the buyer to take on the liability indefinitely.

Recommendation: Staff should delete the terms related to buyer liability and let the market dictate those terms. As ARB moves toward attempting to approve new protocols on offset projects, this issue will continue to stymie the offset market. This must be addressed going forward. (AGCOUNCIL)

Comment:

ARB staff proposal

The staff is proposing a number of amendments in order to clarify and modify aspects of the offset program. The amendments contemplated address aspects of the program that are applicable to offset project developers.

Gaz Métro's comments

Even though it is not necessary for WCI partners' offset programs to be identical, it must be acknowledged that there are a few differences between the California and Québec offset programs.

One significant difference involves the invalidation provisions relating to the California offsets. Upon original issuance, all California offsets are subject to an eight-year invalidation period, during which ARB reserves the right to invalidate and therefore revoke the offsets if certain defaults occur. After certain conditions are met, offsets can have their invalidation period reduced to three years.

In Québec, the invalidation risk is addressed in a different manner. Upon issuance of offsets to a promoter, only 97% of the total quantity of offsets awarded are transferred to the promoter; the remainder is placed in the Minister's environmental integrity account. Later, if an invalidation occurs, the holder of the invalidated offsets then sees its invalidated offsets replaced with offsets that were held in the Minister's environmental integrity account.

In the secondary market, Québec offsets are a commodity that is very easy to transact, bearing no more risk than a California or Québec allowance. California offsets, on the other hand, are transacted on a regular basis and parties are able to address

invalidation risks through contracts. So-called “Golden CCOs” are also transacted. Golden CCOs refer to California offsets that are sold with a replacement guarantee offered by the seller. Insurance products are also offered by third parties to protect a buyer of California offsets against the invalidation risk.

Furthermore, the “goldenization” of an offset is not a feature that offset developers are generally able to offer, due to their inability to offer financial assurance to cover the invalidation risk for the entire timeframe of that risk. This feature can therefore be offered only by sellers that have strong balance sheets, which has the effect of introducing intermediaries in the process and therefore increases the ultimate costs for buyers, since intermediaries not only sell offsets to cover the invalidation risk that they become liable for, but they also take a premium along the way.

With so many transactions of offsets recorded and with the availability of protection for buyers wishing to limit their exposure to the invalidation risk, we can say without a doubt that the market for California offsets is functioning and active. However, statistics issued by ARB in its 2013-2014 Compliance Report show that offset usage is not evenly distributed among emitters. Some covered entities still prefer to avoid California offsets. Arguably, the invalidation risk and the contractual negotiations behind the purchase of offsets discourages some potential buyers.

Gaz Métro’s recommendations

Gaz Métro believes that the approach taken by the Québec government with regard to the invalidation risk of offsets offers a more suitable and predictable environment for transacting offsets. Accordingly, Gaz Métro recommends that the staff consider adopting changes to its offset program to implement an environmental integrity account in a manner that is substantially similar to Québec’s. Gaz Métro believes that this approach facilitates the transactions of offsets between entities and encourages buyers with a more risk-averse profile to buy offsets. (GAZMETRO)

Response: The commenters believe that ARB should remove the requirement for owners of offset credits to replace invalidated offset credits, and one commenter recommends instead establishing an “environmental integrity” account to address invalidation risk, as is done in Québec. This is a general program design comment that does not directly address the proposed revisions to section 95985, which include clarifications and changes to improve the implementation of the program as currently designed. ARB staff has not proposed modifying the buyer liability requirements as part of this rulemaking, and therefore, this comment is outside the scope of the rulemaking and does not require a response. However, contrary to a commenter’s suggestion that a buyer’s liability is for the lifetime of the project, invalidation is limited to at most eight years, and can further be reduced to three years. “Buyer liability” requires that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Even if the covered entity (buyer) replaces any

invalidated offset credits, they may be able to take appropriate action through third-party contractual arrangements they may have established prior to purchase.

Replacement of Invalidated Offsets from Forest Buffer Account

E-4.3. Multiple Comments:

ARB's Proposal to Require Forest Owners to Replace Invalidated Offset Credits in the Forest Buffer Account Should be Improved.

Proposed CTR Sections 95985(h)(3) and (i)(3) require the Offset Project Operator (which for a forest offset project is the forest owner) to replace 50% of any ARBOCs are located within the Forest Buffer Account ("FBA") that have been invalidated. Although at first blush it seems logical that these credits would need to be replaced, the proposed requirement actually does not make sense in the context of the regulatory scheme as a whole.

Under the current Regulation, the only invalidated ARBOCs that must be replaced are those that have been used and thus are in a retirement account. CTR Sections 95985(h) and (i). ARBOCs in the FBA, however, have not yet been used. They have not been surrendered to meet a compliance burden, but rather are placed in the FBA to serve as insurance against unintentional reversals. ARBOCs that have been invalidated pursuant to CTR Section 95985(c) reflect a determination that the credits never should have been issued in the first place – and if they had not been issued, then there would have been no need to insure them against reversal. ARB's proposed requirement that only half of the invalidated ARBOCs in the FBA be replaced appears to be a concession that these credits really do not truly need to be replaced. If not, why is ARB only solving half the problem? (The ISOR does not address the 50% replacement rate.)

We suggest that if ARB wishes to require the replacement of invalidated ARBOCs in the FBA, then to be consistent with the rest of the Regulation the number to be replaced should be tied to the number of credits that have been retired from the FBA. This could be done by administering the FBA in such a way that an equal percentage of credits present in the FBA from each offset project are used to compensate for an unintentional reversal. This equalizes the risk of invalidation with the requirement to replace credits retired from the FBA across all forest offset projects, which would harmonize better with the general insurance goals of the FBA. While we do not anticipate ever being in a position where the invalidation provisions affect us, ensuring the integrity of the Program as a whole can only benefit all involved. (SEALASKA, SEALASKA2)

Comment:

§95985(h)(3) – Replacing Invalidated Buffer Pool Credits

We suggest that ARB change the 50% value for buffer account credits required to be replaced due to invalidation to a number that is instead representative of the percentage of buffer account credits that have actually been used in the program to date (i.e., at the time the invalidation occurs). For example, if only 10% of buffer account credits have been retired at the time of the invalidation, the OPO would only be responsible for replacing 10% of its original contribution to the buffer account, rounded up to the nearest whole number. We believe this approach based on a real representation of the buffer account balance is more equitable than an arbitrary 50%. (CLIMACTRESERV)

Comment:

(§95985(h)(3)) – “The Offset Project Operator, identified in section 95985(e)(3), of an offset project that had ARB offset credits removed from the Forest Buffer Account pursuant to section 95985(g)(1)(A)3. or (g)(1)(B) must replace 50 percent of the ARB offset credits removed from the Forest Buffer Account, rounding up to the next whole number, with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2)”

Bluesource recognizes that ARB is suggesting this amendment to address the perceived risk that invalidation of carbon credits could lead to the elimination of buffer pool credits that had already been retired to compensate for unintentional reversals from other projects; however, we believe there is a better approach to addressing this issue than a blanket 50% buffer replacement requirement:

We recommend the number of buffer account credits required to be replaced in the case of an invalidation be calculated on a project by project basis, based on the total percentage of buffer pool credits that have been retired to compensate for reversals up to the date of the invalidation. For example, if 5% of the total tonnes collectively contributed to the buffer pool had been retired at the time an invalidation occurred, the OPO responsible for the invalidated credits would be required to replace 5% of the buffer account contribution associated with the invalidated tonnes. This approach would ensure the integrity of the buffer pool, the primary goal, and is a justified amount instead of an arbitrary 50%. (BLUESOURCE)

Response: The above comments focus on the new subsections 95985(h)(3) and (i)(3) proposed in the 45-day amendments, which would have required forest offset project operators and current forest owners to replace 50% of the offset credits removed from the Forest Buffer Account in the event of invalidation of offset credits.

The commenters assert that requiring forest offset project operators and current forest owners to replace 50% of invalidated offsets amounted to an arbitrary requirement, and that the percentage should instead be based on the total percentage of Forest Buffer Account credits that have been retired. ARB staff agreed with the commenters and amended the proposed changes to section

95985(h)(3) in the first 15-day amendments and section 95985(i)(3) in the second 15-day amendments. The proposed changes would now require the number of invalidated Forest Buffer Account offset credits that must be replaced to equal the percentage of offset credits retired from the Forest Buffer Account for unintentional reversals as of the date the Executive Officer makes the final determination of invalidation. ARB staff believes these further amendments address the commenters' concerns.

E-4.4. Multiple Comments:

§95985(h) – Requirements for Replacement of ARB Offset Credits

ARB has proposed language that states that the Offset Project Operator identified in section §95985(e)(3) (i.e. the current or most recent Forest Owner(s)) of an offset project that had ARB offset credits removed from the Forest Buffer Account pursuant to section §95985(g)(1)(A)3 or (g)(1)(B) must replace 50 percent of the ARB offset credits removed from the Forest Buffer Account. We think that holding existing landowners liable for replacement of the credits in the Buffer Account is going to severely hamper the ability to sell land with a carbon project developed on it. This provision essentially turns forest carbon projects into a real encumbrance on the property.

We urge ARB to delete this proposed change because it is not necessary to maintain the integrity of the Forest Buffer Account. If forestry offset credits from a certain Reporting Period are invalidated, they will be removed from the appropriate Retirement Account or Holding Account, and the corresponding credits originating from that Reporting Period will be removed from the Forest Buffer Account. However, because all of these credits will be removed from the system simultaneously, the overall risk ratio for forestry projects within the Cap and Trade system remains the same.

A hypothetical example may be illustrative here: If we assume the Cap and Trade system consists of two forest offset projects, A and B. Each generated 100 credits in its first reporting period, and of those credits, 20 from each project went into the Forest Buffer Account (pursuant to a 20% risk rating) yielding an overall buffer percentage for the system of 20%. If the credits from Project A are invalidated, the 80 credits from Project A are removed from the appropriate Retirement Account⁴¹⁰ and the 20 credits from Project A are removed from the Forest Buffer Account. The system now only has 100 credits in it (all from Project B), but the overall buffer percentage is still 20% because the buffer credits from Project B still remain. If we then assume the 80 invalidated credits are then replaced with non-forestry credits, the integrity of the buffer pool still remains intact.

However, under the proposed language, the Forest Owner of Project A would now have to procure 10 additional offsets (50% of the 20 removed due to invalidation) and add them to the 20 offsets from Project B existing in the Forest Buffer Account. The

⁴¹⁰ We'll assume it's a Retirement Account for the purposes of this example.

system would now have 110 offset credits, but 30 would be part of the Buffer Account, thereby raising the percentage of offsets in the Buffer Account to over 27% of the overall offsets in the system.

If ARB's goal is to increase the overall percentage of offsets in the Forest Buffer Account, we think it is more efficient to increase the percentage of offsets required to be placed into the Buffer Account at the time of project issuance. The Offset Project Operator at the time of issuance can factor in these increases into its overall planning and budget at the project outset. Placing the burden of replacing offsets on existing landowners (who may be an entirely different entity than the original OPO) will make it increasingly difficult to buy and sell land enrolled in the compliance program. Future purchasers of forestland will address this new liability by discounting the acquisition price of the land enrolled in the program. Because the price of offsets could potentially increase significantly over time, it will be exceedingly difficult for potential buyers to accurately assess the risk, leading to a disproportionate discount on land prices. (FINITECARBON)

Comment:

8. The Proposal to Require Forest Owners to Replace Invalidated Offset Credits in the Forest Buffer Account Should be Improved.

Proposed CTR Sections 95985(h)(3) and (i)(3) require the Offset Project Operator (which for a forest offset project is the forest owner) to replace 50% of any ARBOCs that are located within the Forest Buffer Account ("FBA") that have been invalidated. This is not consistent with the rest of the Regulation. At present, the only invalidated ARBOCs that must be replaced are those that have been used and are in a retirement account. CTR Sections 95985(h) and (i). ARBOCs in the FBA have not yet been used. They have been placed in the FBA to serve as insurance against unintentional reversals. CTR Section 95802(a)(153). ARBOCs that have been invalidated reflect a determination that the credits never should have been issued in the first place. And if they had not been issued, then there would have been no need to insure them against reversal.

Put differently, the proposed change will result in the FBA growing well beyond what is reasonable or necessary. In the event of an invalidation, the invalid ARBOCs are obviously no longer in the system. Used invalidated ARBOCs are replaced by valid ARBOCs — a percentage of which are already in the FBA and adequately insured against unintentional reversals. To require replacement of any part of the invalidated ARBOCs in the FBA will add additional but unnecessary protection against unintentional reversals of projects that are no longer represented in the system.

The ARB has determined, correctly we believe, that the FBA adequately protects valid ARBOCs against unintentional reversals, and that the current percentage of withholding ARBOCs to the FBA adequately estimates the risk of such reversals. The proposal would increase the withholding beyond what ARB has determined to be necessary. indeed, the fact that the proposal only requires 50% replacement itself suggests that

ARB sees replacement as not solving any particular problem, else replacement would solve only half of it. If not a solution to a problem, this proposal must instead be punitive or a means to discourage operators from taking the risks associated with participation in the program, neither of which is an appropriate goal. We respectfully suggest that this unnecessary and unreasonable proposal be dropped. (AHTNA)

Response: The above comments focus on new subsections 95985(h)(3) and (i)(3) proposed in the 45-day amendments, which would have required forest offset project operators and current forest owners to replace 50% of the offset credits removed from the forest buffer account in the event of invalidation of offset credits for U.S. Forest offset projects.

ARB staff disagrees with the commenters' assertion that requiring the forest project operator to replace invalidated offsets from the Forest Buffer Account is not necessary to provide protection against reversals. The changes to make replacement from the buffer account equal to the percentage of Forest Buffer Account offset credits retired for an unintentional reversal are consistent with the example provided by Finite Carbon. If there has not been an unintentional reversal, there is not a requirement to replace credits invalidated from the buffer pool.

Looking at the example provided by Finite Carbon, using the proposed modified regulatory language, and amending the example to include an unintentional reversal, one can clearly see the need to replace offset credits in the Forest Buffer Account. Taking the same two projects being issued 100 offset credits each, and each contributing 20 percent to the Forest Buffer Account, there are a total of 200 offset credits in the system and 40 offset credits in the Forest Buffer Account. In the case of a small wildfire that results in the unintentional reversal of 10 metric tons of carbon dioxide equivalent, 10 offset credits will be removed from the Forest Buffer Account, leaving 190 offset credits in the system with only 30 offset credits in the Forest Buffer Account, or approximately 16 percent in the Forest Buffer Account. As in the example above, if all 100 credits from one of the projects are invalidated, this would result in 90 offset credits in the system, and only 10 offset credits in the Forest Buffer Account (approximately 11 percent of the total). The modified regulatory language would require replacement of an amount of offset credits equal to the percent of the credits removed from the Forest Buffer Account for unintentional reversals, 25 percent or 5 offset credits in this example. This would leave 95 credits in the system and the Forest Buffer Account with 15 offset credits or exactly the same percentage as before the invalidation. As can be seen from this example, ARB staff continues to believe it is necessary to replace the invalidated credits from the Forest Buffer Account to maintain the integrity of the account.

Furthermore, ARB did not propose changes to the percentage of offsets required to be placed into the Forest Buffer Account upon issuance, therefore the

commenter's suggestion that this percentage be changed in lieu of requiring replacement of invalidated offsets from the Forest Buffer Account is outside the scope of this rulemaking.

Other commenters suggested that, instead of requiring 50 percent replacement, the percentage may be equal to the percentage of offsets already retired from the Forest Buffer Account due to reversals. ARB staff agreed with this suggestion, and this is reflected in the 15-day amendments as discussed in ARB staff's response to Comment E-4.10.

Miscellaneous

E-4.5. Comment:

Carbon capture and sequestration power plant projects using captured carbon dioxide for enhanced oil recovery must not be certified as projects that sequester carbon for the purpose of carbon credits of any kind. Also, injection of carbon dioxide for sequestration purposes shall not take place without the express permission of all surface landowners above the zone of sequestration in order to qualify for carbon credits. (EJAC)

Response: The commenter is opposed to including carbon capture and sequestration as an offset protocol, or to issuance of carbon credits for sequestering power plant derived carbon dioxide emissions. Carbon capture and sequestration projects are outside the scope of this rulemaking. Therefore, no response is required. However, emissions from power plants are covered emissions under the Cap and Trade Program, so sequestration of power plant emissions would not be eligible for offset credits.

E-4.6. Comment:

Data Collection – timely and comprehensive data collection is essential to avoiding negative impacts and ensuring co-benefits. Such data must include:

- a. emissions from forestry and wood products, since forest management is a net source of greenhouse gases.
- b. wildlife habitat (including agricultural land) to facilitate conservation and link to the greenbelt.
- c. metrics to quantify the greenhouse gas benefits of managing natural and working lands. Achieve consensus on how to measure greenhouse gas emissions reductions from activities in natural systems. Discuss and agree upon these metrics with the interagency working group and community stakeholders...

Continue to work with local communities and other stakeholders to refine metrics and tools that better quantify the greenhouse gas benefits and co-benefits of managing natural and working lands, including urban green spaces and trees. Achieve consensus

on how to measure greenhouse gas emissions reductions from activities in natural systems. (EJAC)

Response: This comment generally mentions quantification of GHG emissions reductions from forestry activities, but does not directly address any specific part of the Cap-and-Trade Regulation or the Compliance Offset Protocols for U.S. forest or urban forestry offset projects. Regardless, ARB did not propose changes to either protocol; therefore, this comment is outside the scope of the rulemaking and no further response is required.

E-4.7. Comment:

Ban agricultural burning of waste; Provide a baseline credit for applying carbon back to soils. (EJAC)

Response: This comment is outside the scope of the rulemaking, as ARB has not proposed any bans on burning nor a new offset protocol for soil-based carbon. Therefore, this comment does not require a response. Nevertheless, ARB staff are committed to evaluating additional offset types to ensure sufficient offset supply.

E-4.8. Comment:

Divert dairy waste as fertilizer and for carbon sequestration before it can be converted to methane...

Perform a complete lifecycle analysis of dairy and other bio-digester technology and related infrastructure investment. If biogas from dairies is converted to bio-methane, ARB must mandate that vehicles servicing digesters and converters utilize that gas as a primary fuel source. This is a better use of the fuel than building new pipelines and related infrastructure to transport the gas to other locations. (EJAC)

Response: This comment regarding dairy waste and dairy biogas does not directly address the Cap-and-Trade Regulation or Compliance Offset Protocol Livestock Projects. Regardless, no changes were proposed to the livestock protocol or requirements for livestock offset projects; therefore, this comment is outside the scope of the rulemaking and no further response is required.

E-4.9. Comment:

Integrate urban forestry within local communities. Revise the goal of increasing tree canopy by 5% by 2030 to 20%–30% by 2030. Conduct research to identify methods of achieving that increase given drought conditions. Include urban tree and greenspace maintenance, not just planting/creation...

Expand the definition of “urban forestry” to include “rural desert urban forestry,” “rural/urban interfaces,” and “rural desert communities,” so those areas can qualify for funds to support tree planting. (EJAC)

Response: This comment related to urban forestry does not directly address the Cap-and-Trade Regulation or Compliance Offset Protocol Urban Forest Projects. Regardless, no changes were proposed related to the protocol for urban forest projects; therefore, this comment is outside the scope of the rulemaking and no further response is required.

E-4.10. Comment:

Quantify potential local jobs created from regenerating forests, both urban and rural. Include jobs for maintenance of all green environments, and increase funding to support local workforce development in support of this industry. (EJAC)

Response: This comment regarding job creation is outside the scope of the rulemaking; therefore, it does not require a response. Regardless, no changes were proposed related to the protocols for urban forest or U.S. forest projects; therefore, this comment is outside the scope of the rulemaking and does not require a response.

E-4.11. Comment:

In consultation with all stakeholders including tribal councils and local communities, design and implement healthy forest management strategies that ensure sustainability of the existing forest canopy and decrease extreme wildfire events. (EJAC)

Response: This comment regarding implementation of healthy forest management strategies does not directly address requirements in the Cap-and-Trade Regulation or Compliance Offset Protocol U.S. Forest Projects. Regardless, no changes were proposed related to the protocol for U.S. forest projects. Therefore, the comment is outside the scope of the rulemaking and no further response is required.

E-4.12. Comment:

CODA has continually advocated for increased transparency in regards to how ARB staff review projects, where projects are in the review process and making it easier for market participants to review ARBOC issuance and project future issuances. For example:

- We would like to see transparency around ARBs bi-weekly meetings with OPRs. This could take the form of inviting OPOs / APDs to part of the call where any non-project specific updates are discussed and/or publishing meeting minutes;
- Provide an easily accessible and searchable format showing project and issuance information and latest project information. The current format, whereby parties need to manually search three different OPRs which display different information and transcribe information manually from ARBs website makes this process challenging; and

- Provide further information on the project review process. ARB appears to have a process for reviewing documentation / project issuance requests. If all or part of this process were able to be made public then OPOs, APDs and verifiers would be better able to prepare information so that ARB could review more efficiently.

(CODA)

Response: This comment regarding ARB's weekly conference calls with OPRs, ARB's internal process for reviewing offset projects, and format of publicly available offset issuance information does not directly address requirements in the Cap-and-Trade Regulation. Therefore, the comment is outside the scope of the rulemaking and no further response is required.

E-5. Compliance Offset Protocols

Crediting Period

E-5.1. Multiple Comments:

We Support the Proposal Regarding Required GHG Emission Reductions But it Should Be Broadened to Include Jurisdictions Like Alaska.

The Initial Statement of Reasons (August 2016) (the "ISOR") states that ARB "[staff] is proposing clarification that if a law, regulation, or legally binding mandate to limit GHG emissions that directly applies to an offset project goes into effect during the crediting period of a project, then the project may continue to receive ARB offset credits for the remainder of their crediting period, but may not renew their crediting period." *Id.* at 56. We support this proposal to protect the reasonable expectations of those that have made significant investments in developing compliance offset projects under California's Cap-and-Trade Program. However, proposed CTR Section 95973(a)(2)(G) is unduly limited to a GHG reduction requirement that "comes into effect in California or in a linked jurisdiction." It does not address what happens with offset projects in other jurisdictions that are not linked, such as Alaska. We respectfully request that the provision be expanded to clarify that changes in law, regulation, or mandate outside California or a linked jurisdiction have no effect whatever on the crediting period, even if such changes are to the jurisdiction in which the project is located. (AHTNA)

Comment:

We Support the Purpose of ARB's Proposal Regarding Required GHG Emission Reductions But it Should Be Broadened to Include Jurisdictions Other than California and Linked Jurisdictions.

ARB staff has explained that it "is proposing clarification that if a law, regulation, or legally binding mandate to limit GHG emissions that directly applies to an offset project goes into effect during the crediting period of a project, then the project may continue to receive ARB offset credits for the remainder of their crediting period, but may not renew their crediting period." Initial Statement of Reasons (August 2016) (the "ISOR") at 56.

We support the spirit of this proposal to protect the expectations of those that have made financial investments in the generation of ARBOCs. Protecting such expectations ensures the continued participation of entities willing to undertake the significant effort and expenditure required to develop compliance offset projects.

However, the regulatory language proposed by ARB does not fully support the purpose identified in the ISOR. Proposed CTR Section 95973(a)(2)(G) speaks only to situations where a GHG reduction requirement “comes into effect in California or in a linked jurisdiction.” It does not address what happens with offset projects in jurisdictions such as Alaska. Thus, to account for those jurisdictions outside of California and linked jurisdictions, we respectfully propose the following modification to proposed CTR Section 95973(a)(2)(G):

“If any law, regulation, or legally binding mandate requiring GHG emission reductions or GHG removal enhancements comes into effect in ~~California or in a linked jurisdiction pursuant to section 95943~~ the jurisdiction where the offset project is located during an offset project’s crediting period, then the offset project is eligible to continue to receive ARB offset credits for those GHG emission reductions and GHG removal enhancements for the remainder of the offset project’s crediting period, but the offset project may not renew that crediting period. If an offset project has not been listed prior to the law, regulation, or legally binding mandate going into effect, or the law, regulation, or legally binding mandate goes into effect before the offset project’s crediting period renews, then only emission reductions or removal enhancements that are in excess of what is required to comply with those laws, regulations, and/or legally binding mandates are eligible for ARB offset credits.”

This modification will ensure that offset projects in all jurisdictions are treated equally under the Cap-and-Trade Program, and will incentivize the continued participation of entities outside of California and linked jurisdictions. (SEALASKA, SEALASKA2)

Response: The above comments focus on the proposed new section 95973(a)(2)(G). This new section would clarify that if any laws, regulations, or legally binding mandates requiring GHG emission reductions come into effect during an offset project crediting period, the project may continue to receive offsets for the remainder of the crediting period, but may not renew the crediting period. The proposed language accounted for offset projects within California and linked jurisdictions; however, the commenters pointed out that the proposed language should also include offset projects located outside California and linked jurisdictions. ARB staff agreed and clarified the language in the first 15-day amendments to include jurisdictions outside California. This modification should address the commenters’ concern.

Offset Protocol Versions

E-5.2. Comment:

§95973(a)(2)(D) – Transitioning to a New Version of a Compliance Offset Protocol

This section currently limits an Offset Project Operator's or Authorized Project Designee's (OPO/APD) ability to transition a project to the latest version of a Compliance Offset Protocol. We believe this requirement unnecessarily requires an OPO/APD to continue to use an old version of the relevant Compliance Offset Protocol, even if they would voluntarily choose to transition for a given reporting period. Newer versions of the Compliance Offset Protocols represent the latest policy developments and often contain corrections, improvements, and enhanced usability for both the OPO/APD and the verification body. ARB should allow projects that can meet the requirements of the latest version of a protocol to use it, regardless of when the initial Offset Project Data Report (OPDR) is submitted. (CLIMACTRESERV)

Response: This comment focuses on the existing limitation in section 95973(a)(2)(D) that an offset project operator may only transition a project to the most recent Compliance Offset Protocol version at the initial submittal of the Offset Project Data Report. ARB staff did not propose any changes to this requirement as part of this rulemaking; therefore, this comment is outside the scope of this rulemaking and does not require a response.

Offset Issuance Requests

E-5.3. Comment:

Modifications to Issuance Requirements

CODA supports the changes to allow APDs to request issuance of offsets provided authorization has been received from the OPO. This should help to streamline the issuance process. (CODA)

Response: ARB appreciates the commenter's support.

Miscellaneous

E-5.4. Comment:

I'm especially concerned about how the trade provision kind of prioritizes market transactions over science based standards. Where I see this most prominently concerns offsets. Offsets that involve methane. Methane is increasingly given higher global warming potentials by the inter -- by the scientific community, and they need to be incorporated in offsets, so that the offsets are honest about what is being -- what is actually happening with regard to greenhouse gas elimination, and we're not seeing that. The offsets that are produced by the American Carbon Register, they continue to use very outdated, very long-time interval methane global warming potentials that distort the whole process and basically undervalue and de-value the actual impacts that

methane is causing on the environment. So this is the kind of thing -- and why does this happen? It's because of fungibility. They don't want to disrupt. The American Carbon Registry does not want to modify its protocols, because that would affect the fungibility of carbon credit trading that takes place in the market. They basically are prioritizing a market value over what should be there. (WURU)

Response: Comments on the Global Warming Potentials (GWP) in the American Carbon Registry's protocols are outside the scope of this rulemaking; therefore, no response is required. ARB staff did not propose any changes to GWP values for any of the protocols or the Cap-and-Trade Program in general. Offsets issued by the American Carbon Registry are part of a voluntary market that is separate from the compliance program under Cap-and-Trade. However, with respect to GWPs in the Cap-and-Trade Program, it is appropriate under ARB's Cap-and-Trade Program through 2020 to use the global warming potential from the Intergovernmental Panel on Climate Change Second Assessment, because the entire Program through 2020 is based on the Second Assessment. So it would be inconsistent to use a different assessment which would result in the issuance of more offsets than would be accounted for under the current approved Compliance Offset Protocols. Notwithstanding this, ARB staff notes that amendments proposed for MRR specify that the global warming potentials from the Fourth Assessment will be used starting January 1, 2021. The Cap-and-Trade Regulation specifies that global warming potential values shall be determined consistent with MRR.

E-5.5. Comment:

Increasing guidance and communication on the offset program will also help accelerate the deployment and expansion of dairy digesters throughout California. We suggest more frequent publication of FAQs (i.e. monthly or quarterly) to provide uniform guidance to all of those participating in the program. Currently, most guidance is provided on a case-by-case basis, which leads to varying levels of information and disconnect between Offset Project Operators and Air Pollution Districts: Increasing the FAQ publication frequency to monthly or quarterly would increase both transparency and efficiency in accounting and reporting. Furthermore, once FAQs are published, we recommend that there be a window, such as 90 days, for them to become effective. This would allow for the project operators and air districts to adapt to new interpretations of regulations. (JOSEPHFARMS)

Response: This comment is related to the content and frequency of guidance and FAQs for the Compliance Offset Program. Nothing in this rulemaking requires ARB to produce guidance documents, and the comment is therefore outside the scope of this rulemaking. Nevertheless, ARB staff are committed to producing and maintaining guidance documents to provide additional information to program participants regarding project implementation, verification and issuance processes. However, any guidance document or FAQ published by

ARB is provided for information only; these are not regulatory documents and should not be interpreted as such. The date FAQs are posted should not be interpreted as an “effective” date; since these are not regulatory documents, they have no effective date. To the extent the FAQs explain existing regulatory requirements, those underlying regulatory requirements are already in effect and cannot be delayed or accelerated via ARB’s FAQ documents. Due to the complexity and individual circumstances of offset projects, ARB recommends that program participants contact ARB staff whenever regulatory and/or protocol requirements are unclear.

E-6. Offset Project Data Reports (OPDR)

OPDR Submittal Deadline

E-6.1. Multiple Comments:

We Welcome the Proposed Allowance of Late-Filed Offset Project Data Reports to Satisfy the Continuous Reporting Requirement.

Allowing a tardy OPDR to satisfy the continuous reporting requirement found in proposed CTR Section 95976(d) provides much needed breathing room in what may otherwise be a fairly drastic provision. Forest projects with vast acreages such as many of those in Alaska will require a lengthy, dedicated effort to ensure that all of the information included in the OPDR is complete and accurate. Given the size of the task for these large projects, there is a chance that a report may not be timely submitted. We thus appreciate ARB’s clarification as to what will happen if such an event does occur. (SEALASKA, SEALASKA2)

Comment:

Response: 4. We Support the Proposal to Allow late-Filed OPDRs to Satisfy the Continuous Reporting Requirement.

Allowing a late-filed OPDR to satisfy the continuous reporting requirement in proposed CTR Section 95976(d) provides breathing room in what otherwise can be a fairly drastic provision. Forest projects with vast acreages such as many of those in Alaska will require a great deal of work to ensure that all of the information included in the OPDR is complete and accurate. Given the size of the task, there is a chance that a report may not be timely submitted. (AHTNA)

Response: ARB appreciates the commenters’ support.

E-6.2. Comment:

§95976(d) – OPDR Deadlines and Consequences

The proposed changes to this section appear contradictory, or at the very least, confusing. The section states that if the OPO/APD fails to submit an OPDR, then the Offset Project will be considered *terminated* (emphasis added) and not eligible for ARB

offset credits. It then goes on to say that the OPDR can be submitted after the deadline identified in section 95976(d)(8), but before the end of the next Reporting Period, to maintain continuous reporting. At what point, then, will the project be considered terminated? After it fails to submit the OPDR before the end of the next Reporting Period? If that is ARB's intention, it should be made clearer in the language. It would also be helpful to add a definition of "terminated", as it is only currently used in the regulation in relation to forest projects. (CLIMACTRESERV)

Response: This comment focuses on the proposed language in section 95976(d) regarding when an offset project would be considered terminated upon failing to submit an Offset Project Data Report (OPDR). ARB staff believes the proposed language clearly communicates that an offset project operator has until the end of the next reporting period to submit a late OPDR to maintain continuous reporting and avoid project termination. If an OPDR has not been submitted by the end of the next reporting period, the project will be considered terminated and any termination requirements must be met. "Terminated" has a commonly understood definition of bringing something to an end. The same meaning is applicable to all project types.

E-6.3. Multiple Comments:

We Welcome the Expanded Reporting Deadline for Submitting a Project's First Offset Project Data Report.

ARB's proposal to expand the reporting deadline for the first offset project data report ("OPDR") for a project is a significant improvement over the CTR's current deadlines. Extending the deadline for the submittal of the first OPDR from 24 to 28 months in order to allow a full 24 months of data to be included, giving the project operator four months to prepare the report itself, is both prudent and practical. Many of the ARBOCs generated by a project likely will occur within the first reporting periods, and allowing projects to capture these credits during the initial phase without having to wait for another reporting period will enhance the timely generation of ARBOCs for use within the Cap-and-Trade Program. It also will facilitate annualized reporting periods. (SEALASKA, SEALASKA2)

Comment:

We Support the Proposed Expansion of the Deadline for Submitting a Project's First Offset Project Data Report.

ARB's proposal to expand the reporting deadline for the first offset project data report ("OPDR") for a project makes a significant improvement over the deadlines in the current Regulation. Ahtna could not reasonably assemble its report within the former period if it intended to include 24 full months of data. By extending the deadline from 24 to 28 months, ARB will allow a full 24 months of data to be included, while still giving Ahtna four months to prepare the report itself. Many of the ARBOCs generated by a

project likely will occur within the first reporting periods. This change allows these credits to be captured during the initial phase, which will enhance efficiency. It also will facilitate annualized reporting periods. (AHTNA)

Response: ARB appreciates the commenters' support.

Miscellaneous

E-6.4. Comment:

We Support the Proposed Amendment to Extend the Timeline for Conducting a Post-Unintentional Reversal Carbon Stock Estimate.

We support ARB's proposal to expand the timeline to complete a post-unintentional reversal carbon stock estimate. Proposed CTR Section 95983(b)(1) would allow 23 months for such an estimate to be prepared. For large forest offset projects, providing a complete and accurate carbon estimate could take a long time. Ahtna's contemplated forest project is very large, and so we support this proposed change. (AHTNA)

Response: ARB appreciates the commenter's support.

E-6.5. Comment:

We suggest amending the inclusion of the offset volume stated and verified to only be included on the final OPDR, as the initial OPDR is rarely identical to that of the final OPDR. (JOSEPHFARMS)

Response: The information required to be reported on the Offset Project Data Report (OPDR) is specific to each offset protocol. ARB staff has not proposed any changes to offset protocols as part of this rulemaking; therefore, the comment is outside the scope of the rulemaking and no response further is required. However, all information required to be reported should be as accurate as possible, even in the first version of the OPDR. The OPDR is the basis for verification so must be complete. ARB understand that during the normal course of verification, OPDRs may change, but ARB sees no reason to limit the information provided in the initial OPDR as a result. Therefore, ARB staff did not make the commenter's proposed changes.

E-6.6. Comment:

Modifications to Reporting Requirements

CODA supports the proposed modifications to reporting requirements but requests that ARB add an additional provision for a project to submit a zero credit reporting statement in the event that the project has not been running / operating for the majority of a reporting period. Projects which operate over a 10-year crediting period may in some cases temporarily shut-down or modify operations, resulting in zero offsets being generated (or a minimal number of offsets being generated). Under the current regulations it is not clear how this situation should be handled. It seems to make little

sense to require an OPO to undertake a verification (and pay costs) if a project is not operating or trying to restructure. For projects that are already registered, having the option to forgo the verification (without having to verify) whilst still maintaining future eligibility would be beneficial, it would also reduce unnecessary work reviewing OPDRs and verification reports where zero offsets are being claimed. (CODA)

Response: The commenter asserts that for project types with a 10-year crediting period, Offset Project Data Reports for reporting periods with zero GHG emission reductions should not have to undergo verification. ARB did not propose amendments to the required verification schedule for non-sequestration offset projects (95977(b)), and this comment would not apply to sequestration projects (95977(c)), which have a 25-year crediting period. Therefore, this comment is outside the scope of this rulemaking and does not require a response. However, ARB staff would like to note that a zero reporting period is already part of the existing Cap-and-Trade Regulation in section 95977(b).

E-6.7. Comment:

§95977.1(b)(3)(M) – Correctable Errors

We urge ARB to apply the same common sense approach it did in §95985(b)(1)(A)(1) for minor correctable errors found in early action projects. It is unduly burdensome to force OPO/APDs to fix these minor errors. Instead of requiring the OPO/APD to fix any correctable errors, we urge you to give the OPO/APD the choice to fix minor correctable errors. If minor correctable errors that do not result in an offset material misstatement are found and the verification body does not identify any other nonconformance that would result in an adverse Offset Verification Statement, ARB should allow the verification body to issue a Qualified Positive Offset Verification Statement and identify the correctable errors on the Offset Verification Statement. (CLIMACTRESERV)

Response: The commenter is requesting that the language in section 95985(b)(1)(A)1., which pertains to second regulatory verifications conducted for Ozone Depleting Substances offset projects to reduce the invalidation timeframe from 8 years to 3 years, be applied to section 95977.1(b)(3)(M) which requires the OPO/APD to fix all correctable errors to the submitted OPDR identified during the verification process. ARB staff did not propose changes to the requirement in 95977.1(b)(3)(M) for the OPO/APD to fix correctable errors prior to the submittal of an Offset Verification Statement. Therefore, this comment is outside the scope of the rulemaking and does not require a response. Notwithstanding this, the allowance for not correcting all correctable errors during a second verification is necessary because ARB offset credit issuance is based on the first verification, and cannot be changed unless there is a reason to invalidate offset credits. The second verification either agrees or disagrees with the first verification. A minor error that would not result in invalidation should not be grounds for preventing a reduced invalidation timeframe.

The main opportunity to correct errors before ARB offset credit are issued is during the first verification. The requirement to correct all correctable errors is necessary to prevent over issuance of ARB offset credits to a project that intentionally over reports GHG emissions reductions that do not rise to the level of a material misstatement. The 5.00 percent material misstatement threshold is to account for differences between the verifier's and the project operator's calculated GHG emissions reductions that cannot be corrected.

E-6.8. Comment:

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. (PG&E)

Response: ARB staff is unsure what this comment is asking, as there are no regulatory requirements telling a project operator when they must begin a project. Moreover, ARB staff did not propose this type of change in this rulemaking, so this comment is outside the scope of the rulemaking. Notwithstanding this, a project operator has discretion in choosing when to implement a project, and can choose to delay a project until they feel the market is ripe.

E-7. Verification

Verification Body Rotation Requirements

E-7.1. Multiple Comments:

§ 95977.1. (a) Rotation of Verification Bodies

RCE fully supports the more flexible “six out of nine” rotation requirement for VBs. This helps ensure that conflict of interest provisions are maintained, while also allowing more flexibility for OPOs and VBs. RCE also supports the clarification that commencement dates determine “consecutive projects” for ODS projects. (RUBYCANYON)

Comment:

Modifications to Verification Requirements

CODA supports the proposed modifications, particularly the change to verifier rotation, which would permit greater flexibility by allowing a verifier to verify consecutive reporting periods. (CODA)

Comment:

§ 95977.1. (b) Rotation of Verification Bodies

RCE supports allowing verification services to begin 10 calendar days after the submittal of the NOVS and COI forms to ARB and the OPR. (RUBYCANYON)

Response: ARB appreciates the commenters' support.

Verification Report

E-7.2. Comment:

Proposed revision to the regulation: 95977.1(b)(3)(R)8 –

If ARB or the Offset Project Registry determines that the detailed verification report required pursuant to 95977.1(b)(3)(R)4.a. does not contain sufficient information to substantiate the attestations in the Offset Verification Statement, then the verification body must submit a revised verification report and a revised Offset Verification Statement to ARB or the Offset Project Registry within 15 calendar days.

Comment:

The language “does not contain sufficient information to substantiate the attestations in the Offset Verification Statement” is vague and does not provide an objective basis for the Offset Project Registry (or verification bodies) to determine whether the verification report meets the requirements of 95977.1(b)(3)(R)4a. To ensure consistency across Offset Project Registries and between verification bodies, the regulation should state the specific criteria that a verification report must meet or refer back to 95977.1(b)(3)(R)4a for the requirements that the report must address to be considered in conformance with the regulation. (FIRSTENV)

Response: The commenter asserts that language in the proposed new subsection 95977.1(b)(3)(R)8. is unclear regarding what criteria a verification report must meet. The proposed 45-day language references section 95977.1(b)(3)(R)4.a., which contains the requirements for the detailed verification report. If all the requirements in section 95977.1(b)(3)(R)4.a. are not met, ARB will return the verification report and Offset Verification Statement to the verification body for revisions. The addition of this section was intended solely to place a timeline for responding to an ARB request and not to add additional verification requirements. ARB staff did not make any changes in section 95977.1(b)(3)(R)4.a. Since the criteria are already specified, no changes are required.

E-7.3. Multiple Comments:

§ 95977.1. (b)(3)(R)(8)

RCE would like to request that the length of time to submit a revised OVR and OVS to ARB/OPR be increased to 30 calendar days. While in most cases the proposed 15 calendar days would be sufficient for a VB response, issues sometimes require additional information from OPOs which can require additional time before a resubmittal of the OVR and OVS. In addition, if a request by ARB/OPR occurs during vacation by VB staff or OPO staff, meeting the 15 calendar day requirement could be difficult. (RUBYCANYON)

Comment:

One change here which could allow all parties to a verification a little more time to consider an ARB request, would be to extend the time period for the verification body to respond to a request to change an offset verification report. The proposed modifications state that a verifier will have 15 calendar days to respond to any change requests. This should be extended to at least 30 days to allow sufficient time for the verification body to interact with all of the necessary parties (OPR, OPO, APD etc.), for any changes to the report to be reviewed within the verification body and by the OPO / APD, and if appropriate, to further discuss any changes with ARB. In the experience of CODA members, 15 days is too short a time period for the above to occur, especially if the request from ARB is unclear or requires provision of further information. (CODA)

Response: These comments focus on the proposed new subsection 95977.1(b)(3)(R)8, which would require the verifier to submit an updated Offset Verification Report and Offset Verification Statement within 15 calendar days if ARB determines that the verification report did not meet the requirements in section 95977.1(b)(3)(R)4.a. The commenters request extending this timeframe to 30 days in section 95977.1(b)(3)(R)8. However, 15 calendar days is consistent with the existing requirement in section 95977.1(b)(3)(R)7. to resubmit a revised Offset Verification Statement within 15 calendar days of the OPO/APD resubmitting an Offset Project Data Report. Therefore, ARB staff did not make the commenter's proposed changes.

*Offset Verification Services***E-7.4. Comment:**§95977.1(b)(1) – Notice of Offset Verification Services

With the proposed changes, the OPO/APD is now required to send an OPDR to the Offset Project Registry before verification services can begin. What is the consequence if this requirement is not met? As an OPR, we need clear guidance on what the ramifications are of this process-oriented requirements. (CLIMACTRESERV)

Response: As the commenter notes, section 95977.1(b)(1) was edited to clarify that the OPDR must be sent to ARB or the OPR prior to the start of verification services. If this requirement is not met, a verification cannot take place, so any verification activities would have to be discarded and the verifier must restart verification, including submitting a Notice of Offset Verification Services within the required timeframe ahead of scheduling the required site visit.

E-7.5. Comment:

Changes to this section also appear to shorten the time period OPRs and ARB have to review and approve conflict of interest self-evaluations from 30 days to 10 days. While the Reserve is confident it can meet this expedited timeline, the current process of the

OPR and ARB both needing to review and approve conflict of interest self-evaluations does not happen within 10 days. While this may not require any further changes to the proposed amendments, we urge ARB to re-consider the current process and rely on the OPR's review of conflict of interest self-evaluations to make this process more efficient. (CLIMACTRESERV)

Response: The commenter is concerned that the time to review and approve the conflict of interest self-evaluation has been changed by the proposed modification to section 95977.1(b)(1). The timing requirements for conflict of interest self-evaluation review are in section 95979(f) which was not modified as part of the proposed rulemaking so the comment is outside the scope of this rulemaking. However, to clarify, both the requirements of sections 95977.1(b)(1) and 95979(f) must be met before verification services can commence. If the verifier submits both the Notice of Offset Verification Services and the conflict of interest self-evaluation simultaneously, the conflict of interest must be approved, which may take up to 30 days, before offset verification services can commence.

E-7.6. Comment:

Proposed revision to the regulation: 95977.1(b)(3)(R) –

Offset verification services are not complete until ARB offset credits are issued for the GHG emission reductions and GHG removal enhancements reported in an Offset Project Data.

Comment:

While verification bodies may anticipate questions and comments from ARB or the OPR after submittal of the verification report and statement, the regulation should not define the period between this submission and issuance of ARB offset credits to be part of “verification services.” Consistent with international best practices in financial auditing, third party audit services must have a defined scope including specific starting and ending dates during which the assessment of evidence was performed. To avoid unnecessary uncertainty regarding the scope of the verification process, verification services should be considered complete after the submission of the report and statement to the OPR. This proposed revision should be removed and the regulation can continue to rely on the existing text at 95977.1(b)(3)(S), which states that verification requirements are considered to be met when ARB Offsets are issued. (FIRSTENV)

Response: This comment focuses on the proposed change to section 95977.1(b)(3)(R) clarifying that offset verification services are not complete until ARB offset credits are issued. The commenter states that, in order to avoid uncertainty regarding the scope of verification, verification should be considered complete after the Offset Verification Report (OVR) and Offset Verification Statement (OVS) are submitted. ARB staff disagree with the commenter. ARB

staff cannot begin their review of offset projects until the OVR and OVS are submitted to ARB. Since ARB staff routinely ask for changes to the OVR and OVS as issues arise during ARB's review process, offset verification services cannot be considered complete until ARB offset credits are issued. This is not a practical change from what has been occurring since the program began. Therefore, ARB staff did not make the commenter's proposed changes.

E-7.7. Comment:

Sequestration Project Verification Schedule - The Climate Trust applauds updates to the verification schedule for projects that do not renew their crediting period. Extending the full verification from six to 12 years for projects that meet the stocking requirement provides a strong incentive for landowners to maintain the permanence of their reductions long after the crediting period has ended. (CLIMATETRUST)

Response: ARB appreciates the commenter's support.

E-7.8. Comment:

(§ 95977. (c)) "For offset projects that do not renew their crediting period, verification must still be conducted at least once every six years for the remainder of the project life. However, after a successful verification of an Offset Project Data Report indicating that Actual Onsite Carbon Stocks (in MTCO₂e) are at least 25% greater than the Actual Onsite Carbon Stocks in the final Offset Project Data Report of the final crediting period, the next full offset verification service may be deferred for twelve years. An offset project that has deferred verification for twelve years must resume conducting a full verification at least once every six years if it receives an Adverse Offset Verification Statement."

Bluesource appreciates that ARB is making an effort to improve efficiency in forest project monitoring in the post-crediting phase of a project's life, but the requirement that "Actual Onsite Carbon Stocks [be] at least 25% greater than the Actual Onsite Carbon Stocks in the final Offset Project Data Report of the final crediting period," in order to trigger the 12 year full verification provision, sets the stocking level bar too high to be attainable for many forest carbon projects. This is because projects on mature forests that have been making significant strides in carbon stock accumulation over the course of an entire crediting period will frequently be approaching a climax state under which stocking levels will naturally plateau. In these circumstances, a 25% stocking increase would not be biologically possible.

To make this 12-year full verification provision a viable tool for forest owners, Bluesource would recommend that the stocking increase required to trigger the 12-year provision be adjusted to 10%. Increasing Actual Onsite Carbon Stocks 10% above those seen in the final Offset Project Data Report of the final crediting period should provide ARB staff with the confidence that stocks will not unexpectedly decrease below those for which credits were issued, while making the 12-year full verification provision attainable for forest owners. (BLUESOURCE)

Response: The commenter is concerned that the proposed 25% increase in onsite carbon stocks required to reduce verification frequency may not be achievable. ARB staff agreed with the commenter that a 10% increase in Actual Onsite Carbon Stocks above those seen in the final Offset Project Data Report of the final crediting period would be sufficient to provide confidence that carbon stocks would not unexpectedly decrease, and the next full offset verification could be deferred for 12 years. This change was made in the first 15-day amendments.

E-7.9. Comment:

§95977. Verification of GHG Emission Reductions and GHG Removal Enhancements from Offset Projects

In 95977(c), ARB has proposed new language which states that for “offset projects that do not renew their crediting period, verification must still be conducted at least once every six years for the remainder of the project life. However, after a successful verification of an Offset Project Data Report indicating that Actual Onsite Carbon Stocks (in MTCO₂e) are at least 25% greater than the Actual Onsite Carbon Stocks in the final Offset Project Data Report of the final crediting period, the next full offset verification service may be deferred for twelve years.”

We commend ARB for developing rules that allow forest owners to maintain these projects over the timeframe required in the Compliance Offset Protocol in ways that are more economically feasible for the forest owners participating in the program. However, we urge ARB to change this amendment to allow if the onsite stocks at the end of the final crediting period are 25% higher than the *Initial* Carbon Stocks of the final crediting period then the 12-year cycle will apply.

The purpose of this amendment is to recognize and benefit landowners who have demonstrated a history of significant carbon sequestration during the course of their projects. A 25% increase in carbon stocks is a significant threshold -- a forest growing 3% per year and harvesting only 50% of growth annually would take 15 years to increase stocks by 25%. A landowner who increases stocks 25% during any crediting period demonstrates the same pattern of significant carbon sequestration as a landowner who increases stocks 25% from the end of a crediting period. This revision would provide landowners with an additional economic incentive to sequester more carbon during the crediting period rather than wait until after the crediting period, and earlier emissions reductions are inherently more valuable in addressing climate change than later reductions. (FINITECARBON)

Response: This comment focuses on proposed language in section 95977(c) that would allow projects that do not renew their crediting period to defer the next verification from six years to 12 years if a verification indicates that actual onsite carbon stocks are at least 25% greater than they were in the final Offset Project Data Report of the final crediting period. The commenter asserts that the

amendment should instead allow deferred verification if onsite carbon stocks at the end of the final crediting period (final carbon stocks) are 25% higher than the initial carbon stocks of the final crediting period.

ARB staff disagrees with the commenter. Verification should only be deferred if there is a high level of confidence that the credited carbon stocks will at least be maintained for the remainder of the project lifetime. Therefore, the determination should be made based on the final carbon stocks, rather than the initial carbon stocks, to ensure the permanence of the carbon stocks at the end of the final crediting period.

Therefore, ARB staff did not make the commenter's proposed changes. However, the proposed requirement for the actual onsite carbon stocks to be 25% greater than final carbon stocks to defer verification for 12 years was changed to 10% in the first 15-day amendments, as discussed in the response to Comment E-7.8.

E-7.10. Comment:

§ 95977.1. (b)(3)(D)(1) and (2) Site Visit Requirements

RCE supports allowing certain activities to be conducted as part of a desk review and not at the actual site visit. (RUBYCANYON)

Response: ARB appreciates the commenter's support.

E-7.11. Comment:

§ 95977.1. (b) Rotation of Verification Bodies...

However, RCE would like to request clarification on the site visit 30 calendar day wait period. As the NOVS submittal and COI approval will occur on different dates: Is it 30 calendar days from whichever occurs later 1) NOVS submittal or 2) COI approval by ARB/OPR? (RUBYCANYON)

Response: The commenter is questioning when a site visit can occur. The site visit can occur 30 days after NOVS submittal, but the conflict of interest self-evaluation must also be approved prior to beginning verification services. So if the conflict of interest self-evaluation is not submitted in a timely manner, the site visit cannot occur until the conflict of interest self-evaluation is approved, regardless of when the Notice of Offset verification Services was submitted.

Offset Verification Signatures and Start Date

E-7.12. Multiple Comments:

Finally, thank you for proposing changes to section 95977.1(b)(1) which would allow verification services to begin 10 days after submission of Notification of Verification Services to CARB, and for changes to section 95803 which specifies that on documents

submitted to CARB electronic signatures will have the same legal effect as handwritten “wet” signatures. Both of these are small changes, which will have the effect of significantly streamlining the process of registering offsets in the Cap and Trade program. (AGMETHANE)

Comment:

We support ARB's proposed amendments ... to allow verification bodies to start verification services as soon as 10 days after submitting the Notice of Offset Verification Services. (JOSEPHFARMS)

Response: ARB appreciates the commenters' support.

E-8. Regulatory Compliance

E-8.1. Comment:

In particular we support the modifications to Section 95973(b). Limiting the period of time that a project is not eligible to receive offsets (as a result of regulatory compliance issues) to only the period when the project was out of regulatory compliance is reasonable and prudent. Furthermore, it provides an incentive for projects that may not be in compliance to take necessary actions to come into compliance. CARB's proposed modifications to Section 95973(b) are appropriate, reasonable and will have a substantial impact on streamlining the Cap and Trade Program while simultaneously incentivizing responsible and diligent operation of dairy digester projects.

The current language in Appendix E, Section (b), however, is broad and potentially could be interpreted to penalize good projects for regulatory compliance issues that have no direct bearing on the project or the integrity of the generated offsets. As stated in previous comments the importance of causation in relation to the scope of project activities should be considered. If project activities did not cause the regulatory non-compliance they do not “directly apply”.

For example, post digestion manure is usually stored in an effluent pond. From there manure is eventually land applied. A manure spill that occurs downstream of the effluent pond during land application would not be caused by operation of the anaerobic digestion project. Any farm managing manure whether there is a digester present or not could have a manure spill.

The above principle of causation appropriately limits the scope of project activities that “directly apply” and have a “bearing on the integrity of the generated offsets”. For livestock anaerobic digestion projects, project activities can be interpreted as those associated with manure collection and disposal, and methane collection and destruction. CARB can interpret manure disposal from the project as occurring in the post digestion effluent pond. Manure land application activities not caused by project activities should not be considered directly applicable to the project.

Therefore we propose that CARB amend Appendix E: Offset Project Activities Within the Scope of Regulatory Compliance Evaluation, Section (b) as follows: (proposed amendments are shown with underlined text)

Projects Using a Compliance Offset Protocol in Section 95973(a)(2)(C)2. All project activities associated with the installation and operation of the biogas control system that captures and destroys the methane must be in compliance with all requirements that have a bearing on the integrity of the generated offsets. Project activities begin at waste collection and end at onsite biogas usage and the disposal of associated digester effluents in the project's effluent pond. Project operations relating to the removal, transport or land spreading of manure from the post digestion effluent pond are not considered project activities and do not have a bearing on the integrity of the generated offsets. (AGMETHANE)

Response: The commenter would like ARB to further limit the scope of regulatory conformance for livestock projects to exclude proper waste disposal. ARB appreciates the commenter's support of the proposed changes to section 95973(b) to constrain the period of time certain offset project types may be considered out of regulatory compliance for the purpose of being eligible to receive ARB offset credits during a reporting period.

However, the commenter asserts that the proposed language in Appendix E is too broad and may be used to disqualify projects from receiving ARB offsets for violations that are not project-related, and asks ARB to specify that project operations related to the removal, transport or land spreading of manure from the post-digestion effluent pond are not considered project activities.

The proposed Appendix E language is based on the offset project boundary as established in the appropriate protocol. In the case of livestock projects, waste disposal is a source, sink, and reservoir identified as within the project boundary (SSR 7). Additionally, ARB would not issue ARB offset credits to a project that unlawfully over applied effluent to a field, or unlawfully released effluent into a waterway potentially harming drinking water and the environment. Therefore, ARB staff did not make the commenter's proposed changes.

E-8.2. Multiple Comments:

§95973(b) – ARB Discretion to Find Regulatory Noncompliance

In the Initial Statement of Reasons, ARB specifies that changes to this section give ARB the “discretion to find regulatory noncompliance where noncompliance exists but has not been subject to enforcement action by a regulatory oversight body.” We believe it is inappropriate for ARB to overrule a regulatory oversight body if the body was aware of a noncompliance but chose not to pursue an enforcement action. ARB should rely on the capability of the relevant regulatory oversight bodies outside of California to assess noncompliance. If a potential noncompliance issue is identified by the verifier or ARB

that the regulatory oversight body was unaware of, ARB should notify the appropriate regulatory oversight body and allow that body its own due process to assess and act upon the potential noncompliance. (CLIMACTRESERV)

Comment:

While most of the new language proposed in Section 95973(b) adds clarity and specificity to indicate when a project will or will not be eligible to receive offset credits, the statement, “whether enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance,” would appear to undermine the additional clarity by making every potential regulatory compliance issue – whether or not any official regulatory notification has been received the OPO – subject to interpretation by ARB staff. OPOs and APDs need to have a clear understanding of the regulatory compliance requirements so they may objectively evaluate any potential regulatory issue and manage the resolution prior to reporting and verification. This type of subjective language will burden ARB with numerous case-by-case interpretations best handled by local and state entities and may allow ARB staff in some cases to override the appropriate judgement of local regulatory oversight bodies. Moreover, it opens the door to discretionary determinations and increases the likelihood of inconsistent rulings on potentially identical scenarios over time.

While OPOs, APDs and VBs will undoubtedly evaluate a project’s regulatory compliance status through a review of any and all notifications issued by the applicable regulatory oversight bodies, the proposed language in Section 95973(b) allows ARB staff to consider other factors beyond what is considered official. For example, ARB staff may believe that enforcement action is *likely* to occur, *should* occur, or may simply deem a project out of compliance even in the absence of such notice by the applicable oversight body.

We ask that ARB strike the language stating, “whether such enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance,” so that OPOs and APDs can navigate the non-compliance in a manner consistent with their governing jurisdictions and a systematic, repeatable, and predictable fashion, while reducing the amount of time that ARB staff would spend making case-by-case interpretations. (CODA)

Comment:

IETA is deeply concerned about the inclusion of ARB discretion in determining whether a project is out of regulatory compliance. While most proposed language in Section 95973(b) adds clarity about whether an offset project will (or will not) be eligible to receive credits, the following statement is extremely problematic and has the potential to undermine added clarity: “...whether enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance...” IETA strongly urges ARB to remove this language in the final amended regulation.

As proposed, the above language will spawn uncertainty and risks for offset project operators (OPOs) as well as verifiers. The current regulatory compliance standard references regulatory oversight bodies, which make it clear for OPOs and verifiers who they should look to in order to confirm regulatory compliance. If the amended Regulation allows ARB the discretion to make its own determination of regulatory compliance (above and beyond the applicable regulatory oversight body), this creates an unclear and inconsistent regulatory compliance standard. For instance, if ARB decides that a project has violated its permit, even if the oversight body has not issued a violation, it is impossible for the verification body to verify the project to the requirements of 95973(b) without sending all project EH&S information to ARB for review. It is unclear how a verification body would be able to verify that a project has met the requirements of 95973(b) without first having ARB confirm that a project is in regulatory compliance.

Once again, IETA urges the removal of this language from the final amendment package. (IETA)

Response: The above comments pertain to a proposed clarification to section 95973(b). Section 95973(b) requires offset projects to maintain compliance with all environmental and health and safety regulations that apply to the offset project based on offset project location and that directly apply to the offset project. The proposed change clarifies that whether a project has been subject to enforcement action by a regulatory oversight body is not the only consideration ARB may use in determining whether a project is out of regulatory compliance.

ARB staff disagree with the commenters' assertion that the proposed language should be removed. ARB must be able to evaluate on a case-by-case basis whether violations or potential violations may impact the integrity of the compliance offset credits issued. ARB cannot issue offset credits to a project with a known project-related violation, even if it has not been issued a formal violation by a regulatory agency. There have been instances in which ARB staff has been made aware of clear violations that have not been issued a Notice of Violation by a regulatory agency. While ARB staff does not actively seek out violations that are not within its enforcement authority, once made aware of a violation it may become clear that the project does not fulfill all local, regional, state, and national environmental and health and safety laws and regulations as required by the Regulation. Therefore, ARB staff did not make the commenter's proposed changes.

E-8.3. Multiple Comments:

Materiality Threshold - The regulation still lacks procedures for establishing a materiality threshold for environmental regulatory compliance violations that do not result of material adverse environmental impacts. The Climate Trust urges ARB to revise the regulation to give it more flexibility to determine which enforcement actions result in material adverse environmental impacts. Only those enforcement actions with material

adverse impacts should trigger a violation of regulatory compliance. Material issues must be treated differently than minor administrative violations. (CLIMATE TRUST)

Comment:

Earlier today, we heard moving testimony that I greatly appreciated from the EJ community. Many of them come from Kern County, which is the center of our initial project. And upon careful analysis, I think we'll find that we have a lot more in common than is initially perceived. And I'll cover a couple of those examples as I speak.

We started California Bioenergy 10 years ago, and we are focused on capturing methane for beneficial use, which is electricity generation or vehicle fuel generation.

We have 3 existing electricity projects, and we have 3 more electricity projects that we'll begin construction on later this year.

We have benefited and greatly appreciate funding from CDFA and from the CEC. We are also the winner – one of the finalists, excuse me, in the California Sustainable Freight Action Plan. We just had our cluster in Kern County, including 3 of the projects that are slated to generate electricity to take some of that biogas and put it in a centralized facility, put it into the pipeline and have it be used to replace diesel for freight transportation in the State. That will reduce NOx emissions in the Central Valley, while electricity generation will increase NOx emissions.

I'm here because we're very supportive of efforts by the staff to change the requirements on regulatory compliance. However, they're not sufficient, and I'll give you one example.

The staff takes an important step to limit the loss of carbon credits to the period of the violation, and we strongly support that.

However, often violations won't be recognized for a long period of time. Furthermore, the proposal also addresses all violations, as if they are of equal consequence. The severity of a violation should also be taken into account, since many will be viewed by the regulatory agency as a minor impact.

NOVs, notice of violations -- I'm all done. (CALBIO2)

Response: The above commenters assert that violations that are of lesser severity (e.g. administrative in nature) or do not cause material adverse environmental impacts should not cause an offset project to be considered out of regulatory compliance. While ARB staff understands the concerns of the commenters, no definition of a material or immaterial nonconformance has been provided, and ARB staff have been unable to clearly define the distinction. With a potentially nearly infinite variability in violations given the broad applicability of the majority of ARB compliance offset protocols, it is impossible to develop a one size fits all definition of a material violation. Factors such duration of violation,

intent, severity, and location would all have to be applied in a consistent manner which staff does not believe is possible.

The language of section 95973(b) already provides that a project would only be considered out of regulatory compliance if the violation directly applies to the offset project activities. Any violation outside this very limited scope would not affect project eligibility. ARB staff disagrees that a materiality threshold should be established for determining whether a violation should result in a project being considered out of regulatory compliance. ARB cannot issue offset credits to a project with a known project-related violation. Furthermore, violations may result in environmental impacts beyond impacting GHG emission reductions. Therefore, ARB staff did not make the commenter's proposed changes.

E-8.4. Multiple Comments:

We also have concerns about fair treatment of invalidation timeframe limits across all offset project types. IETA welcomes ARB's proposal to place clear limitations on the invalidation timeframe for regulatory compliance issues for livestock and mine methane capture projects. As previously communicated to Staff, these modifications will give developers greater incentive to bring projects back into compliance as quickly as possible, while limiting the penalty for regulatory non-conformance to the period of time during which the project was out of conformance. However, we strongly encourage ARB to extend modified language related to invalidation timeframe limits to all compliance offset project types. ARB should maintain the flexibility to allow forestry, ODS, and Rice Cultivation offset projects the opportunity to demonstrate that a regulatory non-compliance period limited - one associated with a particular time period during a reporting period - does not impact the entire reporting period's achievements. Where possible, all offset project types should be given the same regulatory treatment, consistent with previous regulatory changes. (IETA)

Comment:

Modifications to Regulatory Compliance

CODA largely supports the proposed modifications and believes that aligning the period of non-compliance with the period of non-crediting appropriately accounts for instances where a project is out of regulatory compliance. It will also incentivize project owners to resolve any non-compliance issue as quickly as possible.

CODA encourages ARB to extend this proposed modification to all project types. Page 56 of the Statement of Reasons states that "Other project types cannot be included in this proposal because there is no quantification mechanism within the applicable protocols to identify and remove crediting of partial Reporting Periods". CODA disputes this blanket assertion. We believe that ARB should maintain the flexibility to allow forestry, ODS, and Rice Cultivation projects the *opportunity to demonstrate* that a regulatory non-compliance period is limited to a particular time period during the

reporting period did not impact the entire reporting period's achievements. For example, in ODS projects, CEMS data would clearly delineate the amount (mass) of ODS fed in and destroyed during any given brief period of non-compliance, and that amount (mass) could be removed from the reporting period. Likewise, if a forestry project was found to be out of regulatory compliance, the carbon sequestration represented in the forest growth and the wood products generated (if any) during the period of non-compliance could be subtracted from the reporting period. This can be accomplished to a high degree of accuracy by accounting for the precise growth and harvesting activities that may have taken place during a period of non-compliance. Furthermore, all offset project types should be given the same regulatory treatment wherever possible, consistent with previous changes to the regulations (for example, when responsibility for invalidated forest carbon offsets shift from the Forest Owner to the holder of the credits in the 2014 regulatory amendments in order to provide equivalence across all protocols. (CODA)

Comment:

§95973. Requirements for Offset Projects Using ARB Compliance Offset Protocols

ARB has proposed language in §95973(b)(1) that significantly changes the consequences of projects being out of regulatory compliance, but only for certain offset protocol types -- including livestock projects and mine methane capture projects. In its Initial Statement of Reasons, ARB stated that "staff determined it is appropriate, when possible, to limit the period of ineligibility to the period the project was out of regulatory compliance." We commend ARB for making this change but we urge ARB to extend this proposed modification to all offset project types including forestry. Applying a "pro rata approach" to regulatory compliance is especially appropriate in the forestry context. Forestry reporting periods are long; the initial reporting period can be 24 months and the subsequent reporting periods are 12 months. A single violation associated with site preparation, planting, harvesting or monitoring often has *de minimus* effects, if any, on the carbon stocks of the forest or the integrity of the generated offsets (i.e. incorrectly harvesting a single tree may lead to a violation in some situations but may have no bearing on carbon stocks). The information used to determine the period of ineligibility -- including documents from the oversight body, monitoring data, and witness statements -- to determine the start and end date of a violation related to those offset project activities that were outlined for the livestock and mine methane protocols could be readily applied to the forest protocol.⁴¹¹ Likewise, the process for determining GHG emissions reductions or GHG removal enhancements for the Reporting Period as

⁴¹¹ For example, the proposed language states that "the date when the offset project is deemed to have returned to regulatory compliance is the date that the relevant local, state, or federal regulatory oversight body that initiated the enforcement action(s) in questions determines that the project is back in regulatory compliance. This date is not necessarily the date that the activity ends or the device is repaired, and may include time for the payment of fines or completion of any additional requirements placed on the offset project by the regulatory oversight body, as determined by the regulatory oversight body." 95973(b)(1)(B). We see no reason why this same standard could not readily be applied to any regulatory body that has oversight of forestry projects.

modified to reflect any period the offset project was out of regulatory compliance that was proposed in the revised Regulation could be applied to forestry projects.

We think that, whenever possible, all of the offset protocols should operate on equal footing. Providing more favorable terms to certain protocol types creates price differentiation in the offset market. This situation arose in previous versions of the Regulation under which Forest Owners were responsible for the invalidation liability from their projects; however, for all other protocol types, the offset buyers bore the invalidation liability under the Regulation. This disparity created a significant price differentiation in the market, and was subsequently corrected so that all protocol types operated under a consistent set of rules. Likewise, we think the rules for determining the period of regulatory compliance must be kept consistent across all protocol types. (FINITECARBON)

Comment:

§95973(b)(1) and (b)(2) – Eligibility and Regulatory Compliance

We applaud ARB's proposal to limit the period of ineligibility for a project to the period the project was out of regulatory compliance; this is how the Reserve's own voluntary program has handled regulatory noncompliance issues since its inception and believes it is an equitable approach to ensure the penalty matches the magnitude of the violation. However, we do not agree that this change should only be applicable to livestock and mine methane capture projects and should instead be changed for all project types listed in 95973(a)(2)(C). Livestock and mine methane operations are not unique in their ability to identify and document the duration of a noncompliance event. Regulatory compliance requirements should be enforced and penalized equitably across all project types. (CLIMACTRESERV)

Comment:

§ 95973(b)(1) Regulatory Compliance

RCE believes that Forestry, ODS and Rice Cultivation projects should also have the ability to demonstrate whether regulatory noncompliance is limited to a certain time period. As a VB, we see no issue with verifying the required information for these projects types in addition to livestock and mine methane capture. It is not clear why these project types have been excluded, and RCE believes that all project types should be reviewed similarly for regulatory compliance. (RUBYCANYON)

Comment:

Invalidation Period - The Climate Trust supports ARB's proposal to place limitations on the invalidation timeframe for regulatory compliance issues for livestock and mine methane capture projects. The change to narrowing the invalidation period to the period of non-compliance creates a stronger signal to develop and bring compliance projects into the system. The Climate Trust encourages ARB to extend this methodology to the

other project types, provided an accurate mechanism to determine the forfeited offsets could be developed. (CLIMATETRUST)

Comment:

Bluesource supports ARB's amendment to limit the period for which a livestock or MMC project would be ineligible to receive offset credits for being out of regulatory compliance to the precise time period during which the project was actually out of compliance, as opposed to the entire Reporting Period; however, we believe this amendment should be expanded to apply to forestry projects as well. While page 56 of ARB's Statement of Reasons document states that "Other project types cannot be included in this proposal because there is no quantification mechanism within the applicable protocols to identify and remove crediting of partial Reporting Periods," we disagree with this conclusion, and contend that credits associated with a particular period of non-compliance could be readily and accurately calculated. Specifically, if a forestry project was found to be out of regulatory compliance, the carbon sequestration represented in the forest growth and the wood products generated (if any) during the period of non-compliance could be subtracted from the reporting period. This can be accomplished to a high degree of accuracy by accounting for the precise growth and harvesting activities that took place during the period of non-compliance. Given this ability to quantify and remove crediting of partial Reporting Periods for forest projects, and ARB's general policy that all offset project types should be given the same regulatory treatment wherever possible, we believe forestry projects should be included with livestock and MMC in the amendment to the regulatory compliance rule. (BLUESOURCE)

Comment:

§95985. Invalidation of ARB Offset Credits

§95985(c)(2) -- Grounds for Initial Determination of Invalidation

ARB has proposed changes to §95985(c)(2) to harmonize this provision with the proposed amendments to §95973(b) (discussed above). The proposed amendments to §95985(c)(2) allow certain offset project types including mine methane capture projects and livestock projects to take a pro rata deduction in offsets credits from a Reporting Period following an invalidation event -- based on the amount of time the project was out of regulatory compliance -- instead of losing offset credits from the entire reporting period. We urge ARB to extend this language to all offset project types including forest carbon projects so that only credits that correspond to the time period that the offset project is determined to be out of regulatory compliance are subject to invalidation.

The risk profile associated with an offset and the consequences associated with its potential invalidation are the primary determinants of price and salability of that offset in the offset market. Creating vastly different rules for determining the consequences of invalidation for the different offset protocols will result in huge disparities in the market

and may have a chilling effect on the marketability of offsets generated under the protocols with less favorable invalidation rules.

We urge ARB to apply the pro rata approach to all offset protocol types. The methods laid out in §95985(c)(2) for determining the period for invalidation for livestock and mine methane could just as easily be applied to forest carbon projects, and everyone in the system – including project developers, regulated entities and offset buyers – benefits from increased consistency, uniformity and equity across the offset market.

(FINITECARBON)

Response: The above comments focus on the new language in sections 95973(b) and 95985(c)(2)(A) allowing for livestock and mine methane projects to be considered out of regulatory compliance for only part of a reporting period, so that the project may still receive offset credits for the part of the reporting period for which there was no violation. The commenters assert that this “pro rata” approach should also be applied to ozone depleting substances (ODS), rice cultivation and U.S. forest offset projects.

ARB staff agreed with the commenters that a similar approach could be provided for ODS projects containing multiple destruction events in a single reporting period. Therefore, ARB staff added the ODS protocol to the first set of proposed 15-day amendments in sections 95973(b)(1) and 95985(c)(2)(A), to specify that ODS projects that are out of regulatory compliance during a destruction event will not be eligible to receive offset credits for that destruction event(s). Under the proposed language, projects containing multiple destruction events would then be able to receive offset credits for the destruction event(s) in the reporting period that do not overlap with the time period of noncompliance.

In order to prorate crediting, the protocol must have a mechanism available to easily remove the days in question. Only the livestock and mine methane capture protocol quantify GHG emission reductions by day. The ODS protocol quantifies emission by destruction event so that would be the minimum timeframe that could be removed from a project. However, both the forest and rice cultivation protocols quantify emissions reductions annually and have no readily available mechanism for removing specific days. Simply dividing the GHG emissions reductions and removal enhancements by 365 days is not a valid method because GHG reductions expected may not be the same each day under these protocols. Therefore, ARB staff did not make the commenters’ proposed changes in relation to the forest or rice cultivation protocols.

E-8.5. Comment:

The amendments would also limit the period of time methane capture offset projects are ineligible to receive ARB offsets for not being in regulatory compliance. This is an interesting concept. Limiting ineligibility would be helpful, but we are unsure at this time how it would work and would like the opportunity to discuss this further. (AGCOUNCIL)

Response: The commenter is remarking on ARB staff's inclusion of language in section 95973(b)(1) of the proposed 45-day amendments to clarify how GHG emission reductions would be modified to reflect a period the project was out of regulatory compliance. However, the comment does not offer any objection or recommended change to the proposed modification. Without further detail on the commenter's specific concerns, ARB staff is unable to provide further response.

E-8.6. Multiple Comments:

We Welcome ARB's Amendment of the Regulatory Compliance Requirement, though More Clarification is Needed.

ARB's clarification in proposed Appendix E of what activities may offend the regulatory compliance requirement set forth in CTR Sections 95973(b) and 95985(c)(2) is a much needed improvement. Specifically, Section (d) of Appendix E brings into the Regulation the commonsense notion that only those activities that actually affect carbon stocks in a forest offset project should be considered for the regulatory compliance requirement. While Appendix E provides much needed clarity, its utility is diminished by the ambiguities in Section 95973(b) that remain unaddressed. The proposed text of CTR Section 95973(b) reads:

"Local, Regional, State, and National Regulatory Compliance and Environmental Impact Assessment Requirements. An Offset Project Operator or Authorized Project Designee must fulfill all local, regional, state, and national requirements on environmental impact assessments that apply based on the offset project location. In addition, an offset project must also fulfill all local, regional, state, and national environmental and health and safety laws and regulations that apply based on the offset project location *and* that directly apply to the offset project, including as specified in a Compliance Offset Protocol. The project is considered out of regulatory compliance if the project activities were subject to enforcement action by a regulatory oversight body during the Reporting Period, although whether such enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance."

The troublesome ambiguity lies in the sentence with the highlighted "and," an ambiguity that is underscored by the somewhat open-ended language that is proposed at the end of the provision. We believe that the correct reading of the sentence with the highlighted "and" is that compliance is required at the risk of invalidation only with those legal requirements that *both* apply to the project location *and* are directly applicable to the offset project. This is consistent with the thrust of Appendix E's focus on *project* activities, and also with the language now proposed for inclusion in CTR Section 95973(b)(2) that also focuses on *project* activities.

However, the provision remains a bit ambiguous. The "and" sentence also can be read to require compliance with legal requirements that apply to the project location *in addition* to those legal requirements that directly apply to the project itself. Under this

interpretation, the violation of, say, a local reporting requirement that is not applicable to the offset project activities but that does apply to the project location could invalidate an entire reporting period's worth of ARBOCs. Such a result would be draconian, especially if it occurs during the initial years of a forest offset project, which is when most of its credits are earned.

In a previous rulemaking addressing section 95973(b), ARB explained that the section only applied to project activities, and went so far as to state "[r]egulatory conformance is intended to be limited to project activities."⁴¹² However, to our knowledge ARB has never directly addressed the ambiguity identified above. We therefore request that ARB reaffirm its interpretation that CTR Sections 95973(b) and 95985(c)(2) as amended mandate compliance at the risk of invalidation only with those legal requirements that directly apply to project activities, thereby making Appendix E the meaningful and helpful addition to the Regulation that it is intended to be. (SEALASKA, SEALASKA2)

Comment:

The Proposed Amendment to the Regulatory Compliance Requirement are Good, though More is Needed.

ARB's proposed Appendix E does much to clarify what activities would fall afoul of the regulatory compliance requirement set forth in CTR Sections 95973(b) and 95985(c)(2). This is a significant improvement, in particular, Section (d) of Appendix E makes clear that only those activities that actually affect carbon stocks in a forest offset project should be considered for the regulatory compliance requirement. While Appendix E provides much needed clarity, we believe that more can be done to clarify Section 95973(b). That provision still can be read to suggest that any violation of a legal requirement that applies to the location of the offset project, though not directly to the offset project itself, can result in the ARBOCs generated by that project being invalidated. Given the vast size of Ahtna's forest offset projects- and thus the scope of the location to which legal requirements may apply — this ambiguity poses a significant risk to our projects. This has been a real concern ever since ARB's 2014 final determination invalidating certain ARBOCs generated by the destruction of ozone depleting substances at the Clean Harbors facility in Arkansas. It is a significant concern as well for certain forest offset projects that are situated atop underground mines. We therefore respectfully request that ARB clarify the regulatory compliance requirement only includes those legal requirements that apply directly to the offset project activities. (AHTNA)

Response: The above commenters are concerned that the language in section 95973(b) may allow ARB to determine that a project is not in regulatory compliance if a violation occurs that is either applicable based on offset project

⁴¹² ARB Final Statement of Reasons (May 2014) at 867 (available at <https://www.arb.ca.gov/regact/2013/capandtrade13/ctfsor.pdf>); see also id. at 628 and 1026.

location *or* directly applies to the offset project, but not both. ARB staff believes that section 95973(b) clearly communicates that a project must fulfill all laws that apply based on the offset project location *and* that directly apply to the offset project. A violation that occurs outside of the project boundary would not meet both of these criteria. Therefore, ARB staff did not make changes to the proposed 45-day language.

E-8.7. Comment:

Section 95973 Requirements for Offset Projects Using ARB Compliance Offset Protocols

(Starts Page 271 & Page 56 of ISOR)

The Regulation requires that offset projects may not receive ARB offset credits for the entire Reporting Period when they are out of regulatory compliance with any local, regional, and national laws. For agricultural projects such as digesters, that potentially could mean a minor notice of violation could cause the entire offset project to be disqualified.

Recommendation:

- ARB should create a right-to-cure provision allowing for the operator of an offset project to fix minor violations prior to disqualifying the project. It is important that offset projects are not eliminated due to a minor violation and that the violations only impact credits until the situation is corrected.

- Separating the digester project, from the dairy it is located at, will be key so that violations confined to the dairy do not have an effect on the digester project.

(AGCOUNCIL)

Response: The commenter asserts that offset projects should be able to “fix” minor violations and still receive offset credits for the period of violation. ARB staff disagree that offset projects should be able to receive offset credits for periods of violation. However, ARB staff agree that violations should only impact the eligibility of the project to receive offset credits until the situation is corrected, to the extent that the affected number of GHG emission reductions can be quantified and documented. This is already reflected in the proposed 45-day language in sections 95973(b) and 95985(c), which provide methods to constrain the timeframe for which the project is not eligible to receive offset credits to the timeframe of the violation.

E-8.8. Comment:

The staff proposal takes important steps forward, but it is vastly insufficient, and we discuss two important examples.

The staff proposal to limit the loss of carbon credits to the period of the violation is one step forward, and we strongly urge that it is supported. However, it is not enough. Violations may occur for long-periods of time and not be recognized. Or even violations that are recognized, for instance a PM 10 reading exceeding the permitted limit by 5%, could take multiple weeks to schedule a second external party test to close out the violation. The proposal also addresses all violations as if they are of equal consequence. The severity of a violation should also be taken into account since many would be viewed by the regulating agency as of minor impact. In short, while the proposal decreases carbon credit revenue risk, significant risk will remain.

The recommendation to limit the boundary of the project is a separate significant step forward, and we strongly urge that it is supported. However, it has an important flaw. It includes within the boundary the effluent from the digester. In the Base Case dairies take manure water from their storage lagoon and use it to fertilize and irrigate their adjacent farmland to grow the feed crops. In a lagoon digester (and we estimate over 95% of manure processed in California digesters are covered lagoon digesters) the same thing happens: the manure water, called effluent, is given back to the farmer to apply to their farmland. If the dairy fails to submit a report, submits a report missing data, makes an error, or does something improper, it will receive a Notice of Violation (NOV). If the digester project does not own or control the effluent, it should not be held responsible and lose vital credit revenue for what is outside its control and is for an on-going process that pre-dates the digester. Thus the project boundary should end when the effluent is handed back to the farmer. By contrast if the project retains ownership of the effluent- for instance if the digester project is seeking to export and sell the nutrients' and in their handling process they receive an NOV, then it makes sense to include the effluent within the project boundaries.

Further, based on conversations with staff, an argument was made that if the digester output effluent goes into the dairy's lagoon, which is where it will likely go prior to irrigation, then the dairy- all of it- will be included in the project boundary. As a result, the advancement of project boundaries that apparently is being made would be illusory. We strongly urge the Board to determine that the project boundary begins at the point of receipt of the dairy manure and ends at the point it hands over the digester effluent whether to the farmer or an external party; and that this boundary is clear and that it assumes the effluent will go into the dairy's lagoon.

While limiting the loss of credits to the period of an NOV and correcting the project boundaries are important steps forward, there remains significant risk of a project receiving an NOV and losing carbon credits and credit revenue, at a potentially significant level. These are complex projects. Especially since an NOV can be a small exceedance of the permitting level, it is our view that there is a risk of a violation of a permit in any given year. It is our understanding this is also the view of the Air District.

The receipt of the NOV and the resulting loss of carbon credits will put a project in financial jeopardy. Moreover, simply the risk of loss of revenues from carbon credits-

and the potential inability for a project to deliver returns to investors, pay bank debt, provide a new revenue stream to farmers, or prevent developers from building a viable business- will result in a significant slowdown in project development- at the very moment we need a massive acceleration.

Further this is a significantly larger issue with R-CNG projects, relative to electricity projects, since GHG methane destruction, as calculated by the ARB protocol, are a greater percentage of the overall revenues, roughly 50% to 60% for R-CNG project versus roughly 15% for electricity projects. As a result, if there is uncertainty over the ability to receive carbon credit revenues, developers will be pushed to projects that generate electricity. However, it will also require a higher electricity price, since the carbon revenue will be uncertain and this higher electricity price may never be achieved in the BioMAT. Furthermore, the risk of regulatory noncompliance, developed with the goal of advancing environmental protection, will inadvertently have a perverse consequence, since it would increase NOx emitting electricity projects while reducing NOx eliminating R-CNG projects fueling diesel truck replacements.

There is an additional important consequence: there are higher regulatory standards in California than many other states. Inadvertently the likely higher incidence of NOVs within California, based on the greater and tighter monitoring, will likely result in greater risk for loss of carbon credits for California based dairy manure reduction projects than those in other states, and result in a relative slowing of California digester projects and the inability to meet SB 1383's objectives.

We understand one considered reason for the requirement for a project to have 100% perfect regulatory compliance comes from the CEQA process that was used to support the regulation. It is important to note that while that may be important for many offset protocols in the case of dairy digesters many if not most projects are deemed CEQA exempt by the responsible agency (usually the Air District) since they have a diminutive effect on a large dairy's manure operation, yet deliver substantial benefits. As a result, there may be grounds to exempt dairies from this historically global ARB CEQA approach.

A Recommended Approach

The solution is to think significantly anew not incrementally about the issue of regulatory compliance. We and others suggest to ARB that the policy should be changed to make clear that an NOV that reduces carbon credits should only be those NOVs that impact greenhouse gas reductions. This would leave the other environmental and worker safety impacts to the local, state and federal agencies chartered with regulating these issues. Further, if a project is failing to address its NOV with the agency issuing the NOV then and only then, should its revenues from its reduction of GHGs be in jeopardy.

While there is a long history of the current interpretation of limiting carbon credits based on NOVs of any type, we would suggest the code itself provides an alternative approach.

In the Regulatory Code (Version dated 11-1-15), 95973, Requirements for Offset Projects Using ARB Compliance Offset Protocols, (b), it states:

"Local, Regional, and National Regulatory and Environmental Impact Assessment Requirements. An Offset Project Operator or Authorized Project Designee must fulfill all local, regional, and national requirements on environmental impact assessments that apply based on the offset project location. In addition, an offset project must also fulfill all local, regional, and national environmental and health and safety laws and regulations that apply based on the offset project location and that directly apply to the offset project, including as specified in a Compliance Offset Protocol. The project is out of regulatory compliance if the project activities were subject to enforcement action by a regulatory oversight body during the Reporting Period. An offset project is not eligible to receive ARB or registry offset credits for GHG reductions or GHG removal enhancements for the entire Reporting Period if the offset project is not in compliance with regulatory requirements directly applicable to the offset project during the Reporting Period." (Emphasis added).

If "directly apply to the offset project" and "directly applicable to the offset project" refers to the GHG reduction aspect of the project only, then the relevant regulatory violations; as determined by outside agencies (non ARB agencies), are only those that apply to the GHG reductions. The definition of an offset project, per the Regulatory Code (Definition 245), furthers this interpretation, since it states, "'Offset Project' means all equipment, materials, items, or actions that are directly related to or have an impact, upon GHG reductions, project emissions, or GHG removal enhancements within the offset project boundary." (Note "Project Emissions," definition 296, "means any GHG emissions associated with the implementation of an offset project...")

In the Staff Report: Initial Statement of Reasons, released August 2, 2016 and Scheduled for Consideration September 22, 2016, for instance, where the staff is proposing limiting the penalty for regulatory compliance violations to the duration of the violation, it states,

"Staff is proposing modifications to the requirement that offset projects may not receive ARB offset credits for the entire Reporting Period when they are out of regulatory compliance with any local, regional, and national environmental health and safety laws and regulation that apply to the offset project. The proposed amendments would limit the period of time livestock and mine methane capture offset projects are ineligible to receive ARB offset credits for not being in regulatory compliance to the time period the project was actually out of regulatory compliance, to the extent that time period can be substantiated by documentation." (Section 9 (c), page 70)

If the phrase "off set projects" reflects the code's definition, then the staff's proposal too could be interpreted to mean a project is only out of regulatory compliance if the NOV's impact GHG reductions.

Our focus and proposal to limit NOV's to those that impact GHG reductions are not a means to decrease overall environmental impacts. Rather it is the opposite. The change will increase the reliability of receiving carbon based revenues and, as discussed above, will increase the percentage of projects that produce R-CNG for vehicle use, reducing NOx emissions in the San Joaquin Valley, home to a vastly disproportionate number of disadvantaged communities. Further, we work every day, at advancing the co-benefits of dairy digesters. We construct double-lined lagoon digesters, increasing ground water protection. Digestion increases the mineralization of nitrogen, increasing the percentage in a plant absorbable form. We are studying this issue (and seeking funding for it), since it should further limit the risk of leakage as well as reduce the need for chemical fertilizers. We are also working to develop processes to add effluent into drip irrigation systems, decreasing water use while also increasing nitrogen absorption. A digester improves the starting point for drip irrigation at a flush dairy, providing manure water with less solids and greater consistency. A well designed digester will improve the sustainability, in both meanings of the word, of California dairies. (CALBIO)

Response: First, the commenter is concerned that the proposed modifications limiting the time period the project is ineligible to receive ARB offset credits to the time period of the violation do not go far enough, since violations can occur for a long period of time. ARB staff disagrees that the time period the project is ineligible to receive ARB offset credits should be anything shorter or different than the time period the project is in violation of any local, regional, state and national environmental and health and safety law or regulation. The original environment assessment contained in the Functional Equivalent Document (FED) prepared in accordance with the California Environmental Quality Act (CEQA) (Appendix O of the 2010 Initial Statement of Reasons), made clear that offset projects would be required to comply with all applicable laws and regulations. To ensure the environmental integrity of ARB's Offsets Program, ARB has consistently issued offsets only when the offset project fulfills all laws that apply based on the offset project location and that directly apply to the offset project.

Second, the commenter asserts that the severity of violations should be taken into account when determining whether a project is out of regulatory compliance. This is addressed in ARB's response to 45-day comment E-8.3.

Third, the commenter asserts that for livestock projects, digester effluent should only be included within the project boundary unless and until it is sold. The commenter does not cite a specific section of the Regulation, however staff assumes the commenter is referring to the proposed 45-day language in Appendix E(b), which clarifies which offset project activities ARB considers to be within the scope of regulatory compliance evaluation for livestock projects. ARB disagrees with the commenter that digester effluent should be excluded from the project boundary. Whether or not the effluent remains under the ownership of the

project operator is not relevant to the environmental integrity of the offset credits generated. This is further addressed in the response to 45-day comment E-8.1 (effluent is part of waste disposal).

Fourth, the commenter asserts that the violations that cause an offset project to be out of regulatory compliance should only include violations that affect GHG emission reductions. It is ARB's position that projects with known violations that may result in environmental impacts, including or in addition to violations impacting GHG emission reductions, should not be eligible to receive offset credits for the reporting period or other time period during which the violation occurs, depending on project type as set forth in the regulation. Please see the first paragraph of this response, above.

Fifth, the commenter is concerned that the loss of carbon credits would put a project in financial jeopardy and may result in a slowdown of project development. The simple solution to this issue is to put in place, at the project, procedures and practices to minimize the risk of receiving a violation for project activities.

Sixth, the commenter is concerned that regulatory compliance requirements in the Cap-and-Trade Regulation will disincentivize renewable compressed natural gas (R-CNG) projects. ARB staff does not agree that the main driver in the selection of a R-CNG project versus an electricity generation project will simply be the regulatory compliance requirements of the Cap-and-Trade Regulation. There are multiple factors that would enter into the decision including project size, permitting requirements, R-CNG and electricity prices, capital costs, availability of and eligibility for programs besides the ARB Compliance Offset Program such as BioMAT, U.S. EPA Renewable Fuel Standard and ARB's Low Carbon Fuel Standard, accessibility of natural gas transmission pipelines, and ability to meet interconnection requirements. BioMAT is a California-specific program that allows small California-based renewable bioenergy projects (< 3 MW) to enter into long-term power contracts. Therefore, BioMAT eligibility would only affect a small percentage of all livestock projects. Project developers concerned about regulatory compliance may be more likely to choose R-CNG (if available) over electricity generation to remove biogas destruction from the project boundary, thus eliminating a common source of regulatory noncompliance. Additionally, as noted earlier in this response, electricity generation projects would be subject to permitting requirements, which would include limits for NOx emissions set by the local regulating agency, therefore minimizing project-related NOx emissions. The regulatory compliance requirements of the Cap-and-Trade Regulation are more likely to decrease existing NOx emissions by providing an additional incentive for projects to adhere to their permit limits, as this would be required in order to receive ARB offset

credits, than to be responsible for decreasing reductions in NO_x due to disincentivizing R-CNG production.

Seventh, the commenter is concerned that there is an unlevel playing field since they claim California has higher regulatory standards than other states. The intent of the regulatory conformance provision as stated above is to help avoid environmental impacts from offset projects. It is up to each individual local, regional, state or national regulatory agency to determine if environmental impacts from livestock digester projects are severe enough to warrant regulation. ARB staff have seen regulatory conformance issues from multiple states and have not noted a significant disparity for California projects. Again a solution to the issue is to put in place, at the project, procedures and practices to minimize the risk of receiving a violation for project activities regardless of the project location.

Eighth, the commenter notes that some dairy operations are exempt from the requirements of CEQA. While an individual livestock project may be deemed CEQA exempt by the local permitting agency, that determination does not relieve ARB from its duty to comply with CEQA for ARB's own actions, including this rulemaking.

Finally, to guarantee a revenue stream from ARB offset credits, the commenter is seeking to limit the regulatory conformance requirement, as it applies to livestock digesters, to violations only related to the physical digester, that only affect GHG emissions, and only when the project fails to address the violation. This would not meet the intent of the regulatory conformance requirement as previously explained. Therefore, ARB staff did not make any changes to the proposed 45-day language.

E-8.9. Multiple Comments:

§ 95973(b) Regulatory Compliance

RCE is concerned about the addition of the language “although whether such enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance.” The rationale provided in the Initial Statement of Reasons is that “ARB has the discretion to find regulatory noncompliance where noncompliance exists but has not been subject to enforcement action by a regulatory oversight body.”

This language creates significant large uncertainty and risks for offset project operators (OPOs) as well as VBs.

Our job as a VB is to confirm whether a project has been subject to any violations or enforcement actions during the reporting period. The verification of regulatory compliance includes contacting the applicable regulatory oversight body, typically state environmental agencies. RCE and other VBs do not conduct full environmental

compliance audits, which is beyond the scope of offset verification services. This is a clear verification standard - VBs confirm regulatory compliance with the appropriate agency, and we do not make compliance determinations ourselves. This standard clearly defines, for both VBs and OPOs, the process to confirm the regulatory compliance of a project.

If the amended Regulation allows ARB the discretion to make its own determination of regulatory compliance (above and beyond the applicable regulatory oversight body), this creates an unclear and inconsistent regulatory compliance standard. For example, if ARB decides that a project has violated its permit (even if the oversight body has not issued a violation), it is impossible for the VB to verify the project to the requirements of §95973(b) without sending all project environmental and health & safety information to ARB for a compliance review.

RCE is concerned about whether it would be possible to verify against the revised regulatory compliance language. RCE would not be comfortable signing a verification statement unless ARB has confirmed its determination of regulatory compliance for a project's reporting period. If ARB does not confirm that a project is in regulatory compliance, it is unclear how a VB would be able to verify that a project has met the requirements of § 95973(b). (RUBYCANYON)

Comment:

The proposed changes to the forest offset regulations, in general, provide reasonable clarifications for project implementation. However, more certainty should be provided for the circumstances under which a project would be deemed "non-compliant."

While the Conservancy supports the overall goal to make sure that offset projects are in regulatory compliance in order to receive credits, the current language of Section 95973(b) is very broad and unclear regarding the circumstances under which a project may be deemed noncompliant. This vagueness could discourage landowners from implementing offset projects given the uncertainty and related risk. We recommend that CARB staff provide additional guidance and regulatory language that describe how material the noncompliance must be and the circumstances whereby noncompliance may be identified. (CONSERVANCY)

Comment:

One area we'd like to see clarified is on what is non-compliant. We think for forest landowners need a little more clarity in the rule to encourage them to participate. (CONSERVANCY2)

Response: The commenters assert that the language in section 95973(b) regarding circumstances under which a project may be deemed noncompliant is broad. However, the proposed 45-day amendments also included the addition of Appendix E, which provides further clarity on which project activities fall within the scope of regulatory compliance. A project must be in compliance with all

local, regional, state and national laws and regulations that apply to the project to be eligible to be issued ARB offset credits. With respect to the commenter concerned with signing off on a verification related to regulatory conformance without ARB's explicit determination of regulatory compliance, ARB staff notes that the proposed modifications clarify existing requirements – they do not add additional verification requirements nor alter how projects are assessed. A project can be out of compliance even if it did not receive a formal violation notice from a regulatory agency if ARB is aware of a violation. Therefore, ARB staff did not make any further changes to the proposed 45-day language.

E-8.10. Comment:

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. (PG&E)

Response: This comment is unclear; however, ARB staff assumes the commenter is referring to the proposed amendments in section 95973(b)(1) allowing for certain projects to still receive offset credits for part of a reporting period when the project is considered out of regulatory compliance during the reporting period. The commenter does not specify why they believe the proposed language is asymmetric or problematic. This language was included to minimize disputes by allowing the relevant regulatory agency to make the determination of the time period the project is out of compliance thus minimizing any dispute between ARB and the project. Therefore, ARB staff can provide no further response.

E-8.11. Comment:

§95973(b)(1)(B) – Written Determination from Regulatory Oversight Body

Regarding the need for the relevant regulatory oversight body to provide a written determination regarding the date when the project returned to regulatory compliance, we suggest you clarify that ARB will accept email as an acceptable form of written communication. This has been the case under the current program in practice to date, but as not all regulatory oversight bodies are forthcoming with correspondence, especially on the time frame needed to stay on track for verification and issuance, it would be valuable to make it clear to stakeholders that email is an acceptable form of written communication. (CLIMACTRESERV)

Response: ARB staff considers email to be a valid form of written communication for the purposes of documenting when an offset project is back in regulatory compliance. Therefore, since email would be considered as a “written determination,” no modification is required.

E-8.12. Comment:

Based on the experience of operating one of the longest producing digesters in California, we strongly support ARB staff recommendations and proposed amendments focused on utilizing incentives, capital cost investment, and streamlining strategies to help accelerate the deployment and expansion of dairy digesters throughout California. In addition, we support the proposed language for Modifications to Regulatory Compliance and Additionality Requirements that includes limiting the period of time livestock and mine methane capture offsets are ineligible to receive credits for not being in regulatory compliance to the time period the project was actually out of regulatory compliance. This will help both ensure compliant projects and avoid substantially hindering projects that reduce greenhouse gas emissions and provide beneficial economic, energy, and environmental outcomes.

Below are our suggestions and comments on the 2016 Cap and Trade Regulation, specifically related to the offset program for the dairy industry:

We support ARB's proposed amendments to clarify the Offset Project Data Report (OPDR)... (JOSEPHFARMS)

Response: ARB appreciates the commenter's support.

F. COMPLIANCE OBLIGATION SURRENDER

F-1. Changes to Compliance Obligations

Surrendering Compliance Instruments for Under-Reporting

F-1.1. Comment:

Section 95858(c). Compliance Obligation for Under-Reporting in a Previous Compliance Period

ARB has proposed to change the date by which additional compliance instruments must be surrendered to account for the under-reporting of emissions in a previous compliance period. Whereas the current regulation requires surrendering compliance instruments within six months, ARB's proposed change would require that compliance instruments be surrendered at the next compliance event.⁴¹³ This change would provide less certainty than the current six month deadline. LADWP requests ARB provide clarification on what "next compliance event" means. (LADWP)

Response: Annual and triennial compliance events are always conducted on November 1 of each year. The entity that underreported would cover the underreported emissions on the next November 1 after the amount of underreported emissions is determined. This revision provides several benefits. First, entities may cover the emissions with any vintage allowance that may be

⁴¹³ 2016 ISOR Appendix A at 141 .

used at that compliance event. They will not have to procure allowances with a vintage matching the years for which they underreported. Second, neither the entity nor ARB will have to conduct a separate compliance event. The amount of allowances needed to cover the underreported emissions is simply added to the amount already due on November 1.

Compliance Schedule

F-1.2. Comment:

NAIMA makes the following requests for clarification in the final regulations:...

NAIMA requests clarification on compliance schedule. (NAIMA)

Response: The commenter requests clarification on a compliance schedule, although the commenter does not recommend specific regulatory amendments. ARB staff notes that the compliance schedule for the Cap-and-Trade Program has not changed. The operative requirements and deadline for surrendering instruments contained in section 95856 have not been modified in this rulemaking. As such, no further response is needed.

G. AUCTION AND TRADING REQUIREMENTS

G-1. Bidding Requirements

Bid Guarantee Options

G-1.1. Multiple Comments:

Amendments to Sections 95912(j) and 95892(b) Would Help Improve Market Efficiencies

The Proposed Amendments would revise Section 95912(j) regarding bid grantees. Bid guarantees are an important part of ensuring that transactions can be successfully completed. However, bid deposit requirements increase transactional costs to market participants and compliance entities. CARB can help reduce the impacts of these additional costs by recognizing the differences between market participants that do not already hold allowances in the Compliance Instrument Tracking System Service (CITSS) and those that do. For those entities that already hold allowances in CITSS, the bid deposit requirements for each quarterly auction should be reduced. It is possible to do this without compromising the integrity or security of the market for several reasons. First, those entities that already have compliance instruments in CITSS can use those instruments as collateral to offset bid deposit requirements, in which case the value of the bid deposit remains unchanged. This would allow the market to operate more efficiently by reducing transactional costs, particularly for smaller entities. Similarly, when compliance entities are consigning allowances into an auction where they have signed up to participate as a buyer, they should be able to use the consigned allowances as collateral to offset bid deposit requirements that would

otherwise be required. These minor adjustments to the bid deposit requirements in section 95912(j) would go far to increasing the efficiencies for compliance entities holding CITSS instruments. (NCPA)

Comment:

ARB should reduce the bid deposit requirements for participation in the quarterly auctions, allowing for offset from entities already holding allowances in CITSS or from compliance entities consigning allowances into the same auction. Bid deposit requirements when no credit RISK to CARB exists, increase transactional costs to market participants for no reason.

a) Entities holding allowances in CITSS should be able to use those as collateral to offset bid deposit requirements. This would allow the market to operate more efficiently by reducing transactional costs for participating in auctions, particularly for smaller entities for whom the cost of posting such bid deposits or surety bonds can be excessive.

b) Similarly, compliance entities consigning allowances into the same auction should be able to use those as collateral to offset bid deposit requirements. If their consignments are larger than or equal to their purchases, why is there any credit risk to CARB or a need for a bid deposit.

c) CMCA supports the concept of bid deposits where credit risk to CARB exists but not when there is zero risk as detailed in the cases above. If CITSS rules need to be modified to allow CARB to use market participants' holdings as collateral, CMCA supports this change and requests such to facilitate this recommendation.

d) Since the cap and trade market was launched, we have been in a historically low interest rate environment where the cost of capital has been quite reasonable. As the Fed is now openly looking to move interest rates up, the cost of providing bid deposits will also increase to multiples of current levels and so the time for CARB to reconsider these regulations in order to keep costs reasonable and low for market entities is now. (CMCA)

Response: Staff acknowledges that auction participants bear a cost from providing a bid guarantee. As has been made clear in previous rulemakings, staff has opposed the use of allowance holdings as collateral for several reasons.

First, such a process imposes an administrative burden on ARB and the auction participants. Allowances held as collateral would have to be "frozen" in order to be available for seizure. Second, the value of the allowances as collateral can vary as market prices vary, and one of the main purposes of the bid guarantee is to protect ARB from financial loss. In addition, such fluctuation would make it difficult for the financial services administrator to evaluate the value of the bid guarantee. Third, such a proposal would benefit the largest holders at the expense of smaller ones. Entities that do not hold many allowances, especially

those that purchase their annual needs at a single auction, may not have allowances to use as collateral. Entities that have received allocations, whether for their own use or for consignment, would obtain a cost advantage over participants that do not receive such allocations. Since these allocations are made to prevent leakage or to provide benefits to ratepayers, any seizure by ARB of these allowances for non-payment of bids would negate the purpose for which the allocations were made. Moreover, staff has not proposed any amendments in this rulemaking to allow for this. As such, the comment is outside the scope of this rulemaking.

Surety Bonds as Bid Guarantees

G-1.2. Comment:

We appreciate the opportunity to provide comments to the California Resource Board (“the Board”) regarding the captioned proposed amendments to the California Greenhouse Gas proposed regulations, particularly the amendment set forth in Section 95912 (j)(1)(D), which eliminates the option to use a surety bond as a form of guarantee to secure a bid obligation. This amendment does not serve to protect the interest of the public.

Section 95912 (j)(1) currently states that a surety bond could be used as a form of guarantee to secure bid obligations. In its Initial Statement of Reasons, the Board contends that surety bonds are not a feasible form of bid guarantee and that bonds “are not commonly available with an ability to meet the requirement to be payable within three business days of [a] payment request.” It is common practice in the surety industry for a bond obligee (beneficiary) to draft the bond terms and conditions. Thus, the obligee can dictate the terms and conditions of the bond, including the number of days during which the surety must pay under the bond. If the issue being addressed is the lack of adequate bond language in regards to a payment request, that issue is more effectively addressed by developing a standard bond form that incorporates the bid guarantee requirements as set forth by the Board, rather than eliminating the surety bond option. SFAA is available to assist the Board in developing such a template bid bond. To eliminate the bond option, however, does not serve to protect the interest of the public and therefore, we suggest the surety bond option should not be deleted.

Surety bonds provide two valuable services. The better-known service of a surety is to perform its stated bond obligation and provide financial protection in the event the bond principal defaults in its performance (such as failing to pay the bid price when due). In such an event, the surety steps in to make payment pursuant to the conditions of the bond and the applicable statutory or regulatory language.

While payment is a critical function of the surety, another equally critical function is the surety’s prequalification of a principal before the surety will write a bond. A surety will review the capabilities and financial strength of bond applicants and provide bonds only to those entities that the surety has determined are capable of performing the

underlying obligation. This prequalification service facilitates the goal of having qualified bidders participating in the auction. (SURETY)

Response: Staff appreciates the comment and understands the services offered through a surety; however staff maintains through the experience of conducting multiple California-only and joint auctions that eliminating a surety bond as a bid guarantee form offers a more efficient design, budget, and implementation process for the financial services administrator and auction administrator. Staff have clarified the requirements for acceptable bid guarantee forms in the second 15-Day Notice Package such that letters of credit and bonds issued consistent with U.S. banking laws and bank practices are the acceptable forms of a bid guarantee for interested auction applicants.

Confidentiality of Bid Prices

G-1.3. Comment:

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; (PG&E)

Response: Staff believes the commenter's suggested change is unnecessary, because the comment takes an overly broad interpretation of the text. As the ISOR states, the purpose of the change was to clarify the existing requirement that secondary market transactions cannot specify purchase at an auction. The modification extends the meaning of bidding strategy to include specifying an auction settlement price or range of prices at which an entity is willing to buy or sell allowances. Entities doing this could signal their bidding strategy at auction or arrange for proxy bidding. This prohibition does not apply to frequently-observed contracts in which entities agree to pay an auction settlement price (or other price index) plus a margin, without specifying where the allowances were acquired.

Support for Increasing the Compliance Instrument Holding Limit

G-1.4. Multiple Comments:

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....

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. (PG&E)

Comment:

SCPPA urges staff to further explore alternative programmatic options that could better firm and shape the market in the short-term. This includes an option to increase restrictive —holding limits for regulated entities. (SCPPA)

Comment:

ARB should increase Holding Limits for CITSS account holders by 200% and standardize purchase limits for all market participants at 25%.

a) CARB's definition of a "Compliance" entity vs. a "Speculative" entity is arbitrary and does not accurately identify speculative vs. compliance purchases or market holdings and provides no useful information or protections to the market. CMCA uses the following examples to illustrate these arguments.

i) Entity A is a financial institution such a bank that typically provides financing services to the market. This bank only purchases Allowances from market participants in order to sell back to them the same volumes at a later date, effectively allowing participants to finance inventory of allowances at a cheaper rate than their internal cost of capital. The

bank may also purchase allowances at auction in order to sell allowances to entities that cannot participate in the auctions in a cost competitive manner. This bank is acting as a financial intermediary to the market and provides a valuable service without taking any material “Speculative” positions. Under current CARB rules this entity would be classified as a “Speculative” entity even though none of its’ activities are “Speculative” in nature and its ability to provide these financial intermediation services is limited by CARB rules possibly harming market liquidity or costs for “Compliance” entities that would otherwise be able to use this bank’s services.

ii) Entity B is a large firm specializing in financial “Speculation” but this firm imports into California 1 MWh per quarter to qualify as a “Compliance” entity. It’s “Compliance” obligations are less than 2 tons per year, yet it is classified as a “Compliance” entity under CARB rules and has all the same purchase and holding limits as the largest “Compliance” entities in the market. Entity B purchases and activities are classified as “Compliance” in market reports and disclosures but it is clearly a “Speculator”.

b) CMCA recommends that CARB standardize rules for all market participants and allow for larger holding limits to accommodate the proper functioning of the market and not unduly limit liquidity. If CARB has concerns about Speculative abuses, CARB should ask for more disclosure on holdings and purchases from market participants on a confidential basis, as it already has the right to do under the Regulations. This would allow CARB to monitor the market for potential Market Power abuses without affecting market liquidity, financing costs or financial intermediation.

c) CMCA would like to emphasize that it sees an important role in the market for “Speculative” market participants. Speculative participants provide valuable liquidity and actually reduce volatility by warehousing risk that “Compliance” entities cannot or are not willing to warehouse. Speculative participants buy when the market is viewed by these entities to be oversold and sell when the market is viewed to be overbought.

i) As the market expands with the addition of markets like Ontario in the future, the current regulations need to be modified in order to not limit market liquidity by arbitrary, and in many cases inaccurate, classifications by CARB regulations. (CMCA)

Comment:

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... (PG&E)

Comment:

Additionally, we support staff's proposal for a linear cap decline from 2020 onward rather than a steep adjustment. However, other proposed adjustments to the program will likely -- will -- they won't likely. They will result in allowances being moved to the allowance price containment reserve, as Rajinder explained earlier.

These market-tightening measures might seem reasonable in the wake of 2 undersold auctions and low allowance prices, but there is wide spread agreement from cap and trade stakeholders that external legal uncertainty is artificially depressing this market.

These amendments need to put us on track to 2030 rather than provide a short-term fix. And considering the distorting signals of litigation, it's just too soon to implement this suite of market changes.

An alternative way to encourage market demand without making permanent constrictive changes is to increase the holding limit for compliance entities, which need to begin now planning for -- and hedging for 2030 anyway. (PG&E3)

Response: The comments recommending an increase in the holding limit are outside the scope of the proposed rulemaking as staff has not proposed any changes to the calculation of the holding limit.

Regarding the recommendation that all entities receive an equal 25% purchase limit at auction, staff notes that such a change would involve raising the purchase limit for voluntarily associated entities from 4% as well as modifications to the rules governing purchase limits assigned to members of a direct corporate association (section 95910(d)). Staff will continue to work with stakeholders to consider whether making this change would be appropriate in a future rulemaking, and will also investigate the modifications that would be needed to the auction platform and CITSS to effect such a change.

For the comments addressing diversion of unsold allowances, please see the response to 45-day comment H-3.2.

Support for Holding Limit Violations Clarification

G-1.5. Comment:

Section 95920(b)(5)(8). Trading

LADWP supports ARB's proposed clarification that an entity that exceeds its holding limit is not in violation unless it fails to take the available corrective action within five business days.⁴¹⁴ To the extent that an entity exceeds its holding limit and avails itself of the 5 day grace period, it should not be penalized as a violator so long as it performs corrective action before the end of the grace period. (LADWP)

Response: The five-day grace period only applies when an entity exceeds the holding limit at the beginning of the year, and only then when the cause of the exceedance is the reclassification of future vintage allowances as current vintage allowances. Section 95920(b)(5) was modified in the first 15-day amendments to

⁴¹⁴ 2016 ISOR at 258.

ensure this is clear. If the entity is in violation for any other reason, the entity will not have the five-day period to bring its account balances within the holding limit.

Opposition to Extending Deadline for Disclosure of Corporate Associations

G-1.6. Comment:

Consider maintaining the existing disclosure regime for non-ARB jurisdictional markets. In the proposed regulation, parties would have 30 days to submit this information in the case of a “market disruption”—but that is too long to wait, should any sort of market crisis emerge...

Consider maintaining the existing disclosure regime for non-ARB jurisdictional markets because information disclosure will not be a priority for registered entities during a “market disruption.”

The proposed amendments would eliminate the obligation of market participants to disclose corporate associations in related markets, instead substituting a requirement that market participants make such disclosures within 30 days in the event of a “market disruption.”⁴¹⁵ We believe this creates unnecessary risk for minimal gain.

In the event of a profound market disruption, such as what occurred in California’s gas and power markets in 2000-01, market participants may be loath to make such disclosures. Compelling disclosure via legal action will take far more than the 30 days contemplated in ARB’s proposal. While ARB has developed experience as a market monitor in the carbon market over the past several years, this period has not actually illustrated how a disclosure regime would work in a crisis. Experience gleaned from calm waters is not necessarily relevant when presented with a hurricane.

If there ever is a crisis, ARB will want information immediately, not in 30 days—ask any member of California government who served through the 2000-01 electricity crisis and its aftermath. And if there really is a crisis caused by market manipulation—especially arbitrage between a FERC or CFTC jurisdictional market and an ARB jurisdictional market—the entities responsible are not going to want to disclose this information and will likely require ARB to go to court to get it, causing further delay.⁴¹⁶

While we understand the desire to reduce regulatory burdens, both for the agency and for market participants, we are concerned that a disclosure regime that only requires disclosure in a crisis is likely to prove ineffective when it is needed most. (WARA)

Response: Staff believes the proposed language is adequate for two reasons. First, while legal proceedings may have long time frames, ARB may suspend an entity’s account for violating the 30-day disclosure deadline. Second, the

⁴¹⁵ ISOR at 62-65.

⁴¹⁶ For a recent example of how disclosure rules can be used to create delay, see Federal Energy Regulatory Commission, Order Suspending Market-Based Rate Authority, 141 FERC 61,131 (Nov. 14, 2012).

information subject to the longer deadline concerns entities' corporate associations with entities that participate in a market related to the Cap-and-Trade Program, but not the cap-and-trade market itself. California is not the enforcement agency for the related markets. The relevant enforcement agency, the Federal Energy Regulatory Commission, would be responsible for dealing with any immediate crisis, and ARB would participate as appropriate to support such effort. The documentation at issue would be needed to investigate the causes of the events and to help FERC determine the possibility for coordinated market activity between participants in the linked markets.

Moreover, as indicated in the ISOR, any request by the Executive Officer for the information would focus on the related markets that experience a disruption. Not every entity that participates in a related, disrupted market would necessarily be involved. Entities will likely need to conduct some preparations to be able to submit the information within the 30-day deadline. Staff believes that the as-needed disclosures will be timely enough to enable ARB to work with other agencies to conduct investigations into disruptions across related markets.

Support for Exempting Offsets Operators from Disclosure of Corporate Associations

G-1.7. Multiple Comments:

CITSS Changes

CODA supports the modifications which would exempt OPOs from the corporate disclosures requirement. For ARB and OPOs this should reduce work load while still maintaining ARB's ability to review corporate disclosures if required. We would like ARB to clarify that existing OPOs who have already made corporate disclosures will be able to opt into this change to avoid having to continually disclose any changes to their corporate structure going forward. (CODA)

Comment:

Disclosure of Corporate Associations. We support changes to OPOs from the corporate disclosure requirements. This provides greater flexibility while reducing administrative workload for ARB. We recommend that ARB allow existing OPOs, who have made corporate disclosures to ARB, to opt-out of corporate disclosure requirements going forward. (IETA)

Response: Thank you for the support. As long as the Offset Project Operator (OPO) does not hold allowances it will not have to update any previous corporate association disclosures. However, should the entity wish to hold allowances, it will be subject to the same corporate association updating schedules as any other registered entity that holds allowances. Staff need updated information on an entity's corporate associations to correctly apply the holding and purchase limits, and a one-time submission would not be adequate for this purpose.

Clarity of Requirements for Disclosure of Corporate Associations

G-1.8. Comment:

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 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. (PG&E)

Response: Staff appreciates the comments and has made changes to provisions defining individuals with shared roles in the second 15-Day Modifications to the Regulation.

For voluntarily associated entities registering as offset project operators, staff are proposing to provide an exemption from the corporate association disclosures if these entities intend to only hold offsets. Staff view the activities of these entities as limited to a portion of the program that is further limited to the eight percent quantitative usage limit by offset users and is therefore less apt to market manipulation. The proposed amendments would require these entities to disclose their corporate associations before they could hold allowances.

For the proposed streamlining of corporate association disclosure requirements, staff disagree with the commenter’s proposal to add the term “registered” to the beginning of each disclosure requirement of section 95833(b). As summarized in the Initial Statement of Reasons, a registered entity would continue to always have to disclose (a) all direct and indirect corporate associations with other registered entities; (b) all parent entities up through the ultimate parent (even if those entities are not registered); and (c) all direct and indirect corporate associations between chains of registered entities that have a direct or indirect association. Staff previously described in the 2014 FSOR for the amendments to the Cap-and-Trade Regulation that it is important for ARB to understand the relationships between direct corporate associations to ensure effective market monitoring and oversight. Further, registered entities must disclose unregistered direct and indirect corporate associations when the associated entities are part of

a chain of corporate associations between two registered entities. As such, staff declines to restrict disclosures of corporate associations to only registered entities.

Compliance Instrument Tracking Service (CITSS) Registration Requirements and Penalties

G-1.9. Comment:

Account Application. IETA applauds ARB for proposing modifications that facilitate a more streamlined approach to market participation. The modification to allow an entity to have CITSS accounts across multiple jurisdictions for which they hold obligations is a much needed amendment to the program. (IETA)

Response: Thank you for the support.

G-1.10. Comment:

Section 95830(e)(1) and (4). Updating Registration Information

ARB proposes to add a new Section 95830(e)(1) to clarify the timing for updating registration information for registered entities. When there is a change in information registrants have submitted to ARB (e.g. change in directors and officers at an entity), registrants must update the registration information within 30 calendar days of the change. ARB in the ISOR states that it considers the "frequency of updates to be reasonable and necessary to ensure adequate market monitoring activities."⁴¹⁷

Although LADWP has been complying with the 30 calendar day reporting requirement, LADWP proposes that ARB allow electronic submittal of the registration information changes and allow updating of registration information on a quarterly basis, instead of within 30 days, to reduce paperwork and streamline the process. For large entities such as LADWP, there are periods of times when the registration information with respect to changes to directors and officers needs to be updated on an almost monthly basis. The current process requires the registrant to type the information into the form, have an authorized person sign the form, and then mail the original signed form to ARB. Similar to ARB's proposals in this rulemaking to accept electronic signatures, LADWP recommends electronic submittal to streamline the process. Quarterly updates to registration could be timed such that updated information would be available to ARB prior to the quarterly auctions to address market monitoring concerns.

LADWP understands the importance of timely registration and always endeavors to update registration information as required by the Cap-and-Trade Regulation deadlines. However, the Regulation, as reorganized and clarified by the proposed amendments, leaves open the possibility that an entity's ability to comply with the program could be placed in jeopardy for a failure to update registration information, including for unintentional or minor violations of the updating requirements. Section 95830(e)(4)

⁴¹⁷ 2016 1SOR, p. 111

states that "an entity that fails to update registration information by the applicable deadline is subject to the restriction or revocation of its tracking system accounts pursuant to section 95921 (g)(3),"⁴¹⁸ which, as amended, clarifies that when a registered entity has its holding account revoked or suspended it "may not hold compliance instruments or register with the accounts administrator for another set of accounts in any capacity."⁴¹⁹ All existing compliance instruments would have to be sold or retired.⁴²⁰ For example, if LADWP updated the name of one of its officers in CITSS 31 days after the new officer had been appointed,⁴²¹ our tracking system accounts could be restricted, in which case all compliance instruments would have to be retired and we would not be permitted to establish new accounts. This would completely prevent us from complying with the Cap-and-Trade Regulation, or from operating in service of our customers as we are legally required to do.

These potential consequences for a single short-term or unintentional failure to update registration information are severe. While we realize that ARB would not necessarily exercise its discretion to the maximum possible extent in such cases, the possibility of such severe consequences and the lack of any standards governing the exercise of ARB enforcement discretion present an unfair risk for unintentional paperwork violations.

LADWP requests that ARB revise this provision to provide more reasonable penalties and clearer standards that govern the exercise of discretion regarding what penalties apply to what violations. (LADWP)

Response: Thank you for your comments concerning the frequency and mechanism for updating registration information as well as the potential ramifications associated with missing the applicable deadlines in the proposed sections 95830(e)(1) and 95830(e)(4) respectively.

Staff is not proposing changes to the current requirements for disclosure timing as described in section 95830(e)(1). The new section 95930(e)(1) is added to clarify existing disclosure timing requirements specified in sections 95830(c) and 95830(f) to clearly identify the reporting deadline. Staff is keeping the current disclosure timing requirements and considers the frequency of updates to be reasonable and necessary to ensure adequate market monitoring activities. However, staff is proposing to amend section 95803(a) to accommodate the request for electronic submission of required information to provide administrative relief for entities (See response to 45-day comment G-1.11).

The proposed new section 95830(e)(4) is reorganized from existing section 95830(e)(3) to ensure consistency with the new numbering format and to clearly

⁴¹⁸ 2016 1SOR Appendix A at 84.

⁴¹⁹ 2016 1SOR Appendix A at 226.

⁴²⁰ 2016 1SOR 226 ("If registration is revoked or suspended the entity must sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation").

⁴²¹ 2016 ISOR at 64-65.

identify the consequences for an entity that does not update its registration information by the applicable deadlines. Staff modified the regulatory language in Section 95830(e)(4) during the second 15-day comment process to clarify that failure to update registration may result in account restriction or revocation. The proposed section 95830(e)(4) does not contain new substantive requirements.

The comment suggests that minor delays in disclosures could result in significant account restrictions being imposed by ARB to the extent that LADWP could not meet its surrender obligations. Staff considers this an unlikely event. Account restrictions are not automatic. The more severe potential restrictions are included to deter and address covered entities that might engage in significant misconduct, such as market manipulation. Even in such a case, the range of restrictions is designed to allow a covered entity to meet its compliance obligation while preventing it from engaging in further misconduct.

Electronic Document Submission

G-1.11. Multiple Comments:

Section 95803(a). Electronic Signatures

LADWP supports ARB's proposal to accept electronic signatures for the submission of required information, including attestations by account representatives and agents, disclosure of corporate associations, changes in facility ownership, and other submissions. ⁴²² (LADWP)

Comment:

As proposed on page 67 of Appendix A – Section 95803, P&G [Procter and Gamble Manufacturing Company] is glad to see the addition of an electronic submission option. This will greatly reduce the logistical burden of account updates for both Entities and ARB staff. (PROCTER&GAMBLE)

Response: Staff appreciates the support for the proposed amendment to accept information submission electronically with electronic signature as an alternative to hardcopy submittal. The current Regulation has required hardcopy submittal of documentation, with original signatures. Many covered entities have expressed the desire to be able to save time and submit electronic copies. The proposed amendment also specifies information that is submitted electronically with electronic signatures, or by means other than original hardcopy with original handwritten signature, will have the same legal effect as if it were submitted in hardcopy form certified by a handwritten signature.

⁴²² 2016 1SOR at 67; 2016 1SOR Appendix A at 67 (proposed § 95803(a)), 90-91 , 101, 109.

G-2. Other Program Requirements

G-2.1. Multiple Comments:

Change of Representatives. ARB's proposed move to streamline the registration and re-designation process is another welcome change to improved efficiencies in procedure and removal of unnecessary administrative burdens. (IETA)

Comment:

Similarly, as proposed on page 90 of Appendix A – Section 95832, P&G is glad to see the streamlining of the process to change or swap roles of account representatives (PAR and AAR). This also will greatly reduce the logistical burden of account updates for both Entities and ARB staff. (PROCTER&GAMBLE)

Comment:

Simplifying the process for switch between PAR and AAR

Air Products supports the proposed simplification of the process for switching PARs and AARs, foregoing the requirement for signed attestations. (AIRPRODUCTS)

Response: Thank you for the support. The Primary Account Representative and Alternate Account Representative roles have the same authority in CITSS and the attestations to be designated to either role are identical. The existing regulation requiring representatives to submit an updated attestation and signature of an officer of the entity has proven to be excessive for users who switch roles frequently. Staff is proposing amendments to streamline the process to perform a role swap by designated account representatives of the same account.

Exchange Clearing Holding Account Transfers

G-2.2. Comment:

CBL will manage the day-to-day operation of the ECHA as a key component of the CBL Market in order to facilitate the transfer of ownership of instruments associated with the California Cap-and-Trade Program between participants in the CBL Market. This includes procedures to ensure compliance with section 95921(d)(2), which states that *“all of the compliance instruments received by an exchange clearing holding account must be transferred to one or more destination accounts within five days of receiving them”* (Five Day Rule), without unnecessarily burdening participants in the CBL Market with transfers in and out of the ECHA on a daily basis or a transaction basis.

In this regard, we refer:

- Generally to:
 - Proposed regulations:
www.arb.ca.gov/regact/2016/capandtrade16/appa.pdf

- Statement of reasons:
<https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>
- Specifically to the following proposed changes to section 95921(d) which we have labelled the “ECHA Transfer Out Change”:

(d) Transfers Involving Exchange Clearing Holding Accounts.

(3) A request to transfer compliance instruments to ~~or from~~ an exchange clearing holding account does not require confirmation by an account representative of the destination account pursuant to section 95921(a)(1)(C).

(4) A request to transfer compliance instruments from an exchange clearing holding account does not require confirmation by a second account.

We understand the merits of the proposed ECHA Transfer Out Change which in practical terms means that transfers of compliance instruments out of the ECHA cannot proceed without the prior confirmation by account representatives of the destination accounts.

However, a failure by account representatives of a destination account to provide the necessary confirmation could result in compliance instruments being held in the ECHA for a period longer than five days of receiving them amounting to a breach of the Five Day Rule.

While unintended, the Five Day Rule and the proposed ECHA Transfer Out Change are not consistent with each other and may create an unacceptable compliance risk that is not minimal. This risk would be avoided if the proposed ECHA Transfer Out Change was amended or not approved.

As stated above we understand the merits of the proposed ECHA Transfer Out Change, however we believe that the proposed change requires additional consideration.
 (CBLMARKETS)

Response: Staff agrees with the comment and has proposed changes in both of the subsequent 15-Day revisions to address the scenario raised in the comment. The intent of the change was to ensure the entity receiving the transfer from an ECHA is responsible for accepting delivery. The proposed revisions clarify that the exchange will not be held responsible due to a delivery failure caused by the receiving entity. The exchange will notify ARB when a delivery failure occurs.

Banking Allowances

G-2.3. Multiple Comments:

We'd also ask that unused allowances from the third compliance period -- first and second and third compliance period be carried forward into post-2020, so that those

allowances that companies have acquired either through reductions or through acquiring otherwise be continued forward. (CMTA2)

Comment:

NAIMA makes the following requests for clarification in the final regulations:...

NAIMA requests clarification on whether CARB will allow carrying over of surplus allowances. (NAIMA)

Response: Existing section 95922(c) states that allowances do not expire and are not removed from the system until it is retired for some compliance purpose. Staff is not proposing to modify section 95922(c) in the proposed amendments, so the concerns expressed in the comments is unwarranted.

Borrowing Allowances

G-2.4. Comment:

SCPPA also encourages the long-term ability to borrow allowances from future years. (SCPPA)

Response: The existing regulation includes a provision allowing some replenishing of the Reserve with future vintage allowances when the Reserve is depleted. This feature is being extended to include the use of future vintages through 2031 (see section 95871(h)(1)). The use of future vintage allowances for current compliance, other than through Reserve sales, is beyond the scope of these proposed amendments.

Surrendering Future Vintage Allowances

G-2.5. Comment:

Including the ability for covered entities to use a limited amount of future vintage allowances for compliance in the current compliance period. Multi-year compliance periods provide compliance flexibility, but the end of a compliance period still represents a source of instability in the Cap-and-Trade structure. Currently, entities are limited to using only current vintage and past vintage compliance instruments for any compliance event. For the 30% annual surrenders in the early years of compliance periods, this is not a significant market constraint. However, in the final year of a three-year compliance period, the entire period must be made whole with these vintages of compliance instruments, and if demand here stretches supply, prices will inevitably reflect the market tightness. When the limited future-year allowances out in the market are not allowed to be used, they will likely be valued at substantially lower prices in the near-term, reflecting the looser market conditions that will occur at the beginning of the next compliance period. There is a set of market conditions that may result in a three-year sine-wave in market prices, rather than a stable or a stably increasing long-term

price trend. Such a pattern almost certainly will negatively affect investment decisions in emission reducing practices, exacerbating the tight market conditions over time.

A broader concept of "overlapping" compliance periods, where the vintage 2018 allowances that have been allocated prior to the early November compliance period surrender "event" could be available for compliance, again at a premium. Note that not all of the 2018 vintage allowances would be available, as some are auctioned off in the fourth quarter auction every year, too late for the surrender event. The ARB can alter the Cap-and-Trade regulations to increase the allowances held for the final auction if desired. SMUD sees this overlapping concept as providing a market price smoothing effect between compliance periods, without really borrowing from future periods, since the allowances have been allocated or sold in the market prior to the surrender event. (SMUD)

Response: The commenter is proposing to allow future vintage allowances to be used for compliance purposes. Although the current regulation allows some limited borrowing for entities who receive a true-up quantity of allocation, the regulation does not allow the type of borrowing requested by the commenter. Moreover, ARB staff has not proposed amendments that would allow such borrowing (which would be fundamental change from existing policy). As such, the comment is outside the scope of this rulemaking.

Default Information Submission Deadline

G-2.6. Multiple Comments:

Reporting Requirements: Some changes may seem small, but can have a significant impact on implementation. Assigning a default reporting response time of only 10 days is problematic. Many times it is not possible for organizations, either large or small, to respond to an information request in 10 days. This is a very short turnaround time, particularly if the request is complex, requires multiple inputs, or even requires customer authorization to release the data. Defaulting to 10 days is problematic since the nature of future requests is unknown. SCPPA understands that ARB would like a default timeframe, when otherwise not specified; therefore, SCPPA recommends that the default response time be extended to 30 days to ensure sufficient processing times. (SCPPA)

Comment:

Section 95803(b). Submission Deadlines

ARB has proposed a new Section 95803(b) that would add a default submission deadline for all information requested by the Executive Officer of 10 calendar days,⁴²³ with the exception of specific provisions that state a specific date or period of time (e.g. September 1 of each year, 30 calendar days). Because the deadline is set in calendar

⁴²³ 2016 ISOR Appendix A at 67 (proposed § 95803(b)).

days, it is possible that entities would have a maximum of 7 business days to gather and submit information, and as few as 5 days during holidays. This level of time is likely too short to comply with information requests of any complexity. LADWP recommends that ARB establish submission deadlines that are tied to the nature of the requested information. ARB could set a specific reasonable deadline for an information request at the time the request is made rather than a blanket one-size-fits-all requirement. Alternatively, ARB could establish a more reasonable default submission deadline such as 30 calendar days or the approximate equivalent in business days. (LADWP)

Response: ARB staff appreciates the comments. The 10 calendar day deadline established in the new proposed section 95803(b) only applies to information submittal requested by the Executive Officer that does not have an established deadline specified in other provisions of the regulation. Staff has made a number of information requests to registered entities, and based on this experience staff believes the proposed times should be more than sufficient. The modification is intended to provide clarity and ensure all entities subjected to the requirements of the regulation understand the timing of when information requested by the Executive Officer must be submitted.

G-3. Types of Participants

Non-Covered Market Participants

G-3.1. Comment:

[In their January 2010 letter to ARB, included as an attachment to their comments, the commenter states:] Another aspect of the Proposed Regulation that will lead to unintended consequences is that it permits parties that do not have surrender obligations to "opt in" to the auction process. Such parties will participate in the auction solely for their financial gain. These speculators will increase the volatility of the price of emissions, bid up the price of allowances and create the highest possible cost for those with a surrender obligation. Allowing speculators to opt-in that have no vested interest in containing the cost of emissions will likely lead to higher costs to California's families and businesses and achieve no reduction in GHG emissions. (STATEWATER)

Response: The comments are outside the scope of the proposed changes. Staff have not modified provisions that determine who is eligible to participate in the auctions, and voluntarily associated entities (VAE) have always been eligible.

See also the response to comment G-1.4.

Limitation to Domestic Entities

G-3.2. Comment:

In this letter we ask for your consideration to allow an exception to the US location requirement within 95814(a)(2) and 95814(a)(5) for CFTC regulated DCOs applying as Voluntarily Associated Entities and their account representatives, since such DCOs are

already subject to comprehensive US regulation and supervision. Such an approach would be consistent with ARB's oversight role for the Cap and Trade system, facilitate efficient settlement of cleared transactions in California Carbon Allowances and give regulated entities and other market participants a greater number of service providers from whom to choose. This also provides consistency with similar requirements for access to other emissions (or similar) systems in other US States.

Detailed Submission

Intercontinental Exchange, Inc. (ICE) operates a leading network of global futures, equity and equity options exchanges, as well as global clearing and data services across financial and commodity markets. As it impacts the California Cap and Trade market, ICE's US registered futures exchange, IFUS, hosts trading in futures and options contracts with California cap and trade compliance instruments (specifically, California Carbon Allowances) as the underlying delivered instrument. All of the trades conducted on IFUS in futures and options in California Carbon Allowance instruments are cleared at ICEU. ICEU provides clearing services for all IFUS energy division contracts, which includes other futures and options on emissions allowances as well as futures and options involving oil, natural gas and other energy products. The IFUS futures and options on California Carbon Allowances help market participants manage financial and transactional risk associated with the cap and trade program. Since inception in August 2011 and through August 2016, more than 10,000 transactions have been executed in futures and option contracts for over 1 billion allowances. These transactions have resulted in more than 260 million allowances being delivered from seller to buyer. As of August 31, 2016 a total of 144 million allowances are committed for future delivery between buyers and sellers.

ICEU is one of the world's most diverse and leading clearing houses serving many US markets. It provides central counterparty clearing and risk management services for interest rate, equity index, agricultural and energy derivatives, as well as European credit default swaps. ICEU is a Derivatives Clearing Organization (DCO) registered with the US Commodity Futures Trading Commission (CFTC). ICEU is also a recognized clearing house under section 288 of the Financial Services and Markets Act 2000 and EU Regulation 648/2012 (European Market Infrastructure Regulation (EMIR)); supervised by the Bank of England. It has also received the settlement finality designation (SFD) by the FSA under the Financial Markets and Insolvency (Settlement Finality) Regulations 1999, which enhances the systemic risk protection provided to clearing members in the event of a clearing counterparty default. ICEU is also recognized as an inter-bank payment system under the Banking Act 2009 and regulated by the Bank of England.

ICEU also provides clearing services for European credit default swaps (CDS) index contracts. In addition to Bank of England and CFTC oversight, ICE Clear Europe's CDS clearing service is registered as a Securities Clearing Agency (SCA) with the US

Securities and Exchange Commission (SEC). ICEU's CDS clearing services has a separate and discrete risk pool and default waterfall.

ICEU has established a mutualised Futures and Options (F&O) Guaranty Fund of US \$1.55 billion which is prefunded by its Clearing Members. In addition, ICEU contributes US \$100 million to the F&O Guaranty Fund, all of which sits in front of Members' obligations.

One of the fundamental services provided by exchanges and clearing houses is to ensure as far as possible that buyers receive the commodity they intended to buy when the contract goes to delivery, and, vice-versa, the seller receives the relevant sums due. In the current Commodity Futures Trading Regulation the ARB contemplated this role and created a category of account type, Exchange Clearing Holding Account, available to qualifying Voluntarily Associated Entities (VAEs). In order to qualify for an Exchange Clearing Holding Account and to provide exchange clearing services the regulation, 95814(a)(1)(C) requires that the entity be a DCO as defined by the Commodity Exchange Act (CEA) (7 U.S.C. 1a(9)) and be registered with the CFTC pursuant to the CEA (7 U.S.C. 7a-1(a)). However, pursuant to 95814(a)(2) and 95814(a)(5), an entity registering must be located in the United States and at least one individual acting as its account representative must have its primary residence in the United States, respectively.

ICE supports the requirement established by the ARB to require holders of Exchange Clearing Holding Accounts be properly registered DCOs with CFTC. This requirement is logical, consistent with the CFTC regulation of futures trading and clearing and supports ARB's goals for an efficient and robustly regulated program. However, the CFTC does not have a similar US locational requirement and non-US based clearing houses can apply for and obtain "full" DCO status (subject to certain requirements such as appointing a US agent for service of process). Such non-US DCOs are regulated in the same manner as US-based DCOs. However, as a result of the ARB's current location and residency requirements, many of the entities who could provide legitimate and robust Exchange Clearing Holding Account services are not eligible. This is true even while these entities, like ICEU, provide clearing services for US commodities markets (including California Carbon Allowances) to US firms under the jurisdiction and oversight of US regulatory agencies. The lack of direct access to CITSS for such clearing organizations makes the delivery and settlement process for cleared contracts involving allowances less efficient than it could otherwise be. Allowing such access would, in ICEU's view, further the ARB's interest in a liquid, efficient and transparent market and settlement process for California Carbon Allowances.

We ask that ARB allow an exemption to the US location and residency requirements within the regulations for properly registered DCOs and their representatives. We note in this regard that the CFTC has recognized that a DCO, regardless of its location and jurisdiction of organization, can be registered with it and if registered, will be subject to the CFTC's comprehensive regulation, supervision and enforcement regime, in the same manner as any US-based clearing organization. ICEU similarly believes that a

DCO that registers with CITSS will be fully subject to the rules of ARB with respect to covered activity. An exemption from the location and residence requirement would allow the full range of DCOs to register with CITSS, and in particular allow entities, such as ICEU, who provide similar services for the European emissions market, to register.

The following are examples of two very minor regulatory changes (based on the changes that the ARB has already proposed) that would accommodate this request. The examples below are exclusive of each other.

Draft Change Alternative A:

§ 95814 Voluntarily Associated Entities and Other Registered Participants (a)
Voluntarily Associated Entities (VAE).

(1) (2) An individual or entity registering as a voluntarily associated entity must have at least one active account representative with a primary residence in the United States.

(a)(1)(5) An entity registering as a voluntarily associated entity must be located in the United States, according to the registration information reported pursuant to section 95830(c).

(a)(1)(8) An entity and/or individual registering in accordance with 95814(a)(1)(C) is exempt from the residency requirement of 95814(a)(2) and the location requirement of 95814(a)(5).

Draft Change Alternative B:

95814(a)(1)(C) An entity providing clearing services in which it takes only temporary possession of compliance instruments for the purpose of clearing transactions between two entities registered with the Cap-and-Trade Program. A qualified entity must be a derivatives clearing organization as defined in the Commodities Exchange Act (7 U.S.C. § 1a(9)) that is registered with the U.S. Commodity Futures Trading Commission pursuant to the Commodities Exchange Act (7 U.S.C. § 7a-1(a)). Such an entity and its representatives are exempt from the residency requirement of 95814(a)(2) and the location requirement of 95814(a)(5). (ICE)

Response: Staff understands the proposals contained in the recommendations, but cannot support the changes at this time. Alternative B is outside the scope of the proposed regulation amendments, as is the part of Alternative A that proposes a new section 95814(a)(1)(8).

Staff had initially proposed a modification to section 95814(a)(2) in the 45-day amendments that would have broadened the ability of non-U.S. individuals or entities to register, but staff has removed the proposal during the 15-day amendment packages after identifying two problems with the initial proposed change. First, the choice of section 95814(a)(2) was unsuitable as a means of expanding qualifications, as it refers to having a primary residence in the United States. Individuals have a primary residence while entities do not. Second, the

proposed change may have suggested a broader revision of the existing requirement that VAE are located in the United States than staff intended. Staff included the restrictions in sections 95814(a)(2) and (5) based on potential concerns regarding staff not possessing sufficient enforcement resources or authority to take action against registered entities outside the United States. See ISOR for the 2012 amendments to the Cap-and-Trade Regulation. (<https://www.arb.ca.gov/regact/2012/capandtrade12/isormainfinal.pdf>, p. 119.)

Staff may revisit the issue raised by the commenter during a future rulemaking.

H. GHG EMISSIONS BUDGET AND COST CONTAINMENT

H-1. GHG Emissions, Costs and Other Priorities

Balancing GHG Emissions and Costs with Air Quality and Other Benefits

H-1.1. Comment:

ARB must better balance reducing greenhouse gases and reducing costs (cost compliance) with the other AB 32 goals of improving air quality in EJ communities while maximizing benefits for all Californians. There has been too much emphasis on reducing costs to industry, and not enough attention on reducing emissions and their associated costs in EJ communities. (EJAC)

Response: The comment from the Environmental Justice Advisory Committee appears to focus on overall AB 32 goals, related to the proposed 2017 Scoping Plan Update. It does not propose specific changes to any of the Proposed Amendments, so no further response here is needed.

Cap-and-Trade Support and Prioritizing Equity

H-1.2. Comment:

But from the outset, I just want to say, in response to the important issues and perspectives we've heard today from the environmental justice community, from where I stand, I think -- I just want to urge the Board, you know, not to fall into this notion that we have to choose between economy-wide programs of scale that can help extend the reach of California's programs beyond state lines in the face of a global problem and doing more at the local level to redress the real impacts we've heard about today, from air pollution at industrial sites and mobile sources that continue to be disproportionately impacting disadvantaged communities.

I don't think it is an either/or proposition. I think it must be a both/and. We must do both to continue to advance California's leadership on a global scale and continue to do more, which this Board has the power and prerogative to do at the local level.

For a host of reasons thus far, the Cap-and-Trade Program has really served as a supporting cast role on the way to 2020, some by design, such as the need for complimentary policies that have moved markets, broken down barriers, and some by

happenstance, in that what we thought were going to be the emissions we were going to have to reduce in 2020 have been lower than we thought due to the recession and other factors. So the gap that the cap has had to close has been less than we thought, coupled with legal uncertainty of various favors that has meant low demand for allowances, low allowance prices.

That will likely change on the road to 2030, which will require reductions more than double the pace that we have achieved thus far. Without a hard limit on emissions, there's more risk we will not hit that mark. Without a strong market signal, it will likely be more difficult, more costly to achieve that goal. And without significant investments that this program generates to ensure clean energy takes root in communities most in need of them, our program won't have the resources to promote equity.

But that is not an endorsement of the status quo, by any means. As this new resource really underscores, low-income communities, communities of color continue to bear the impacts of our economy's externalized pollution costs, which is unjust and absolutely needs to change.

And while any pathway to achieve a 40 percent reduction goal will invariably involve steep reductions, there are ways that we can design that approach which will put the appropriate emphasis on equity. And we encourage the Board to continue to look at those. (NRDC2)

Response: The comment is made in reference to broader policy discussions in the context of the proposed 2017 Scoping Plan Update, and does not propose specific changes or recommendations on the Proposed Amendments. As such, no further response is required. Notwithstanding this, for a discussion of ARB's efforts related to local air pollution, please also see response to 45-day comment L-1.5.

Continuous Program Adjustment

H-1.3. Comment:

ARB must develop contingency plans for mitigation and adjustment to the overall plan if emissions increase in benchmark years (due to huge leaks like Aliso Canyon, or if certain programs fail to reduce emissions). (EJAC)

Response: The comment suggests changes to the proposed 2017 Scoping Plan Update related to emissions leaks such as at Aliso Canyon. These types of emissions are not included in the Cap-and-Trade Regulation, and the comment is beyond the scope of this rulemaking.

Support for Higher GHG Prices

H-1.4. Comment:

k. Increase the floor price to the real price of carbon; use the highest price offered, not the lowest. Incorporate industry's externalized costs into the cost of carbon (as is done with the mitigation grant program at Port of Long Beach). Calculate the cumulative impacts so they can be mitigated. Ensure that polluting facilities are paying the societal costs of their emissions, rather than externalizing them...

The price of carbon must be increased, with the resulting funds invested in local communities to ensure all benefits from a greenhouse gas free future. (EJAC)

Response: The proposal in the comment to raise the “floor price” appears to be a reference to the Auction Reserve Price, and is out of the scope of the proposed amendments.

The comment also suggests allowing higher prices in general. Related to this, staff has proposed two provisions. First, staff have proposed to add section 95911(g), which would transfer to the Reserve allowances that have been designated for auction but remain unsold after two years. Second, after 2020 the three existing tiers of the Reserve will be consolidated into one tier, and valued at the 2021 value of the currently highest-price tier. The single tier price will be increased over time using the existing mechanism.

See also responses to 45-day comments L-3.2, L-3.3, K-1.5, M-1.28, and N-1.4.

Capping GHG Prices

H-1.5. Comment:

Recommendation: ARB should propose additional mechanisms, including a hard-price cap, to minimize costs in the event that the prices of allowances drastically increase. This is prudent in case ARB has incorrectly assumed that the allowances in the APCR are sufficient to meet the cost containment needs of the program through 2031 and beyond. (AGCOUNCIL)

Response: The proposal in the comment is outside the scope of the proposed regulation amendments. ARB staff notes that with the recent enactment of AB 398, the Legislature has provided additional direction regarding setting a price ceiling. ARB will initiate a new rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Safety Valve for Cost-Effectiveness

H-1.6. Comment:

Cost Containment: ARB has previously acknowledged that Cap-and-Trade cost containment mechanisms are critical towards ensuring the Program's long-term stability.

In Resolution 13-44, the ARB Board directed staff to develop a plan for a post-2020 Cap-and-Trade Program (including cost containment) before the start of 2018 to provide market certainty and address a potential 2030 emissions reduction target. We have previously urged ARB to engage stakeholders as soon as possible in designing, testing, and implementing possible cost containment mechanisms before the 2018 deadline. We further urged ARB to incorporate a meaningful “safety valve” in the event new technologies do not develop; this would allow entities to meet policy goals in a cost-effective manner. (SCPPA)

Response: In response to the Board directive referenced by the commenter, staff promulgated, through an earlier rulemaking, a provision that allows replenishing of the Reserve with future vintage allowances should the Reserve ever be depleted. The current proposed amendments extend this provision through 2031. Staff believes that the provision, along with existing cost containment measures, is sufficient to satisfy any reasonable estimate of demand in the near future. This provision would provide time for ARB to address any underlying market issues.

H-1.7. Comment:

Let me turn now to another issue that potentially creates some market volatility. Specifically, staff as part of the reg package makes a couple of assumptions.

Number one, that the oversupply of allowances is a permanent condition, which needs to be addressed by the regulation rather than market. And then number two, that allowance prices are going to continue to remain low. ARB really should avoid basing major regulatory design elements on the notion that the future of the program is going to look just like it is in the present. Both of those assumptions are going to lead to unnecessary regulatory intervention and potentially increase market volatility. (WSPA2)

Response: The commenter asserts that staff is assuming that current market conditions will be permanent, and that prices will remain low permanently. ARB staff disagrees with the commenter. Staff has proposed amendments which do not reduce market supply or liquidity because those allowances are not on the market, they have never left the auction holding account. Indeed, they cannot be transferred to the Reserve until participants at eight auctions indicate that they are not needed by the market. See response to 45-day comment H-3.2. Despite the commenter’s critique of presumed staff assumptions, this comment does not provide any recommendation for modifying the proposed Amendments. As such, no further response is needed.

H-2. Auction Reserve Price

Increasing Auction Reserve Price Rate of Increase

H-2.1. Comment

CARB should amend the annual auction reserve price calculation from the current 5% + CPI to the greater of 5%+ CPI or 7% such that the annual increase is never less than 7%.

- a) In a negative (or low) inflationary environment, the current regulations suggest that the annual price adjustment could be lower than 5%. This was not the expectation of the government or regulators when the floor was adopted and has resulted in lower carbon prices and revenues than were expected.
- b) A higher escalator would ensure that even in a low or negative inflation environment the reserve price would increase at a more predictable rate and that entities would be encouraged to act now to hedge risk or constrain emissions due to a higher expected cost in the future.
- c) Additionally, a higher and more stable escalation rate would more closely approximate entities cost of capital and incentivize long term investment in offsets and other emission reduction technologies. (CMCA)

Response: ARB staff did not propose modifications to the auction reserve price floor calculation as part of this rulemaking. As such, the proposed changes are outside the scope of the proposed amendments.

H-3. Disposition of Unsold and Consigned Allowances

Support for Moving Unsold Allowances to the Allowance Price Containment Reserve (APCR)

H-3.1. Multiple Comments:

Transfer of Unsold State Allowances to the Allowance Price Containment Reserve Should Help Limit Prolonged Undersubscription and Drive Participation in Near Future Auctions

Calpine supports ARB's proposal to add subsection (g) to Section 95911 to provide for the transfer of unsold allowances to the Allowance Price Containment Reserve (the "APCR") after two years. In recognition of recent auction results and the mounting quantity of unsold allowances accumulating in the Auction Holding Account, reintroducing those unsold allowances into future auctions per the existing framework could depress future auctions, even after the present uncertainties that may be contributing to the recent undersubscription of auctions are overcome.

By creating a mechanism to transfer allowances that remain unsold after two years to the APCR instead, ARB would resolve the dilemma inherent within the existing

framework (i.e. mounting unsold allowances coupled with limited, staggered opportunities for reintroduction of those allowances to the market), which may make it difficult for market participants to appropriately gauge when and whether those allowances will be reintroduced to the auction. By establishing that allowances that remain unsold for two years after first being offered for auction will only be accessible at the higher APCR price levels, ARB's proposed amendment may help buoy auctions in the near-term by signaling to market participants that what may presently be perceived as a temporary deferral of allowances from reintroduction to the auction could, in fact, result in their eventual removal from the Auction Holding Account altogether, prompting market participants to reassess their near- and mid-term (i.e., through 2020) procurement strategies.

Calpine supports ARB's efforts to improve market performance and believes the proposed addition of subsection (g) to Section 95911 is a reasonable and appropriate step towards achieving this goal. (CALPINE)

Comment:

Cost Containment

We support staff's proposal to include a mechanism in advance of the third compliance period to transfer unsold state-owned allowances into the APCR after a period of time rather than remain in the Auction Holding Account potentially indefinitely. This proposal accomplishes two important objectives: first, it provides a means of backfilling the APCR that does not rely on taking allowances from cap budgets set artificially high after 2020 (as discussed above); and second, it provides more of an incentive to market participants to purchase the allowances on offer at each quarterly auction so as to prevent them from being transferred behind a much more expensive paywall. That incentive cuts against the type of 'wait and see' attitude among market participants that the current rules largely accommodate, and which contributed to the low subscription rates of the previous two auctions. To provide an even stronger incentive, however, we recommend ARB shorten the time period from 24 months (or eight auctions) to 12 months (or four auctions).

Proposed Modification to § 95911. Format for Auction of California GHG Allowances

(g) Transfer of Unsold Allowances to the Allowance Price Containment Reserve (Reserve). Beginning January 1, 2018, current vintage allowances designated by ARB for auction pursuant to section 95911(f)(3) that remain unsold in the Auction Holding Account for more than 24 **12** months will be transferred to the Reserve. Current vintage allowances designated by ARB pursuant to this section do not include allowances consigned to auction pursuant to section 95910(d).

(NRDC)

Response: Staff appreciates the commenters' support for the mechanism that transfers unsold allowances in ARB's Auction Holding Account to the APCR.

However, staff declines to incorporate the recommendation to change the time period from 24 months after the initial auction sale date to 12 months as staff do not believe it to be a lengthy enough time to assess market depression and assume that demand for allowances at auction is unlikely to change.

Opposition to Moving Unsold Allowances to the APCR

H-3.2. Multiple Comments:

Key theme: Cost Containment should continue to be a key element of market design.

Cost Containment proposals should not just focus on what the state can do in the event of a sudden allowance price spike, but instead should also consider market design choices that could prevent a spike from occurring in the first place. This regulatory package includes several proposals that could result in the tightening of allowance supply and/or proposals that could increase the costs of compliance for regulated entities.

On the treatment of unsold allowances, JUG members believe that removing allowances from the market into the APCR after two years is premature and could have unintended consequences of significantly increasing the costs of the Cap-and-Trade program. The Cap-and-Trade program has been subject to significant uncertainty due to regulatory, judicial, and legislative controversies. A first-of-its-kind greenhouse gas market could be expected to face such challenges, and is still clearly feeling the effects of lingering uncertainty. JUG members suggest that ARB should continue monitoring market performance and allow current rule challenges to be settled to understand how demand may bounce back after additional certainty appears in the market. The mechanism to hold unsold allowances out of the market for a time should be structured to return them to the market at prices lower than the proposed APCR \$60 plus premium over the floor price. Otherwise, if unsold allowances are removed from circulation into the APCR, prices could spike higher on a rebound than they would if unsold allowances were allowed to continue in circulation in some fashion. (JOINTUTILITIES)

Comment:

The ARB Should Not Move Unsold Allowances Into The APCR In The Third Compliance Period.

The Proposed Amendment to Section 95911(g) would move unsold allowances from the quarterly auctions into the Allowance Price Containment Reserve (“APCR”) starting January 1, 2018. While we appreciate the ARB’s desire to send a signal to the market regarding the overall supply of allowances and the integrity of the Cap-and-Trade markets, we do not believe that signal is needed right now. We do not believe the state should tighten the supply of allowances because there may be longer term implications due to the aggressive GHG reduction goals set for 2030 and 2050. Moreover, between now and the start of the post-2020 program, there will be more certainty regarding the Cap-and-Trade market as the Chamber of Commerce lawsuit is resolved and as the

Governor's office explores a November 2018 ballot initiative. If the auctions continue to undersell into the third triennial compliance period, the ARB should revisit this proposal, but only after the free allowance allocation rules for post 2020 have been approved by the Board. (TURLOCKID)

Comment:

Keeping Cap-and-Trade costs reasonable is extremely important for the long-term viability of the program. While the initial years of compliance experience in the Cap-and-Trade Program have seen reasonable compliance instrument prices, SMUD does not believe that this experience should lead to complacency about prices in future years. Market projections have indicated a potential tightening of demand/supply conditions after 2020, where the proposed increased decline in the cap year to year has the potential to lead to increased upward price pressure....

SMUD does not support the proposed addition of allowances into the APCR that remain unsold at auction for two years. SMUD is concerned that this could have a counterproductive impact on carbon costs in scenarios where these allowances have been removed from the market at current prices and the demand for allowances in some future year picks up sharply. This could cause market prices to shoot right through the APCR soft target into uncharted and politically unpopular territory. The unsold allowances should be available to the market at lower than APCR prices, as intended, even if the fact that they remain unsold for two years is indication of current oversupply. (SMUD)

Comment:

Staff has proposed to change the treatment of unsold allowances, proposing amendments to the cap-and-trade regulation to include a method for transferring state-owned allowances that remain unsold for 24 months to the APCR, with the amendments taking effect by January 1, 2018. In other words, beginning in 2018, any previously unsold allowances owned by the State that have been in ARB's Auction Holding Account for 24 months would be transferred to the APCR.

The Staff-proposed change would only serve to increase allowance costs for compliance entities. This additional measure to tighten the market is premature and may be unnecessary if the current situation is due entirely to legal uncertainty regarding the cap-and-trade regulation (review of the Low Carbon Fuel Standard prices indicates that legal uncertainty can greatly influence the market). Further, while Staff states that this proposed amendment can also be viewed as requiring the completion of eight auctions before the transfer, it is possible under the other auction rules regarding unsold allowances that these are only offered at a single auction. Other rules such as putting the oldest vintage unsold allowances back in the auction first should also be included. The Board should make no change in the cap-and-trade regulation at this time with respect to unsold allowances.

SDG&E Recommendation: The Board should reject new section 95911(g). (SDGE)

Comment:

Transfer of Unsold Allowances to the Allowance Price Containment Reserve

A new proposed provision allows CARB to transfer unsold allowances from the Current Auction, if unsold for 24 months after their initial sale date, to be transferred to the Allowance Price Containment Reserve and made available through a Reserve Sale. This process would come into effect January 1, 2018.

According to CARB, this proposed provision is necessary to allow CARB to remove allowances that remain unsold after two years from immediate availability, and to supplement the Allowance Price Containment Reserve when the market is depressed for a lengthy period of time. However, CARB's the cost of a bigger Containment Reserve to deal with rising allowance pricing, comes at the prices of contributing to a smaller pool of allowance and generating potentially higher prices.

Additionally, CLFP understands that the that the cap-and-trade is back loaded in the third compliance period and given the state's failure to anticipate the most recent auction events, CLFP lacks confidence in CARB's proposed amendment and that such manipulation risks additional damage to the market.

This proposal needs additional vetting before considering it for implementation.
(FOODPROCESSORS)

Comment:

Additionally, we support staff's proposal for a linear cap decline from 2020 onward rather than a steep adjustment. However, other proposed adjustments to the program will likely -- will -- they won't likely. They will result in allowances being moved to the allowance price containment reserve, as Rajinder explained earlier.

These market-tightening measures might seem reasonable in the wake of 2 undersold auctions and low allowance prices, but there is wide spread agreement from cap and trade stakeholders that external legal uncertainty is artificially depressing this market. These amendments need to put us on track to 2030 rather than provide a short-term fix. And considering the distorting signals of litigation, it's just too soon to implement this suite of market changes. (PG&E3)

Comment:

Cost Containment Provisions Must Be Strengthened in the Face of a Tighter Market and Ever-Decreasing Cap.

The tighter emissions cap will make Program compliance more challenging moving forward, as evidenced by several studies, including the PATHWAYS studies being used to assess the Scoping Plan impacts. NCPA understands that the issue of cost containment may seem far-fetched at this time, especially in light of the clearing price of

allowances at the last few auctions. However, as the Program moves forward and the cap is tightened, it will be increasingly important that compliance entities be able to acquire the allowances they need to meet the mandates of the Program without severe financial hardship to the ratepayers and the California economy.

NCPA appreciates that the Proposed Amendments acknowledge the importance of cost containment and provide for continued funding for the Allowance Price Containment Reserve (APCR) post-2020. At this time, however, it is premature to transfer unsold allowances in CARB's Auction Holding Account into the allowance price containment reserve and remove them from the market generally. While the last few auctions have been undersold, CARB and stakeholders must be able to determine that this is not simply a reaction to perceived uncertainties regarding the Program, rather than pure market fundamentals. It is important that the APCR continue to be funded, but not at the risk of compromising the liquidity of the market in light of what may be transient market anomalies. NCPA recommends that the Proposed Amendment to section 95911(g) be removed at this time, and that this option be reviewed at a future time if there continue to be excess unsold allowances. (NCPA)

Comment:

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...

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 overallocation 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".⁴²⁴ 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

⁴²⁴ Air Resources Board. Proposed Amendments to the California Cap on Greenhouse Gas emissions and Market-Based Compliance Mechanisms ISOR p. 12. August 2, 2016.

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...

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. (PG&E)

Comment:

ARB staff proposal

The staff is proposing amendments to the Regulation to include a method for transferring to the Reserve State-owned (not consigned) allowances that remain unsold at auction for a significant period of time, with the amendments taking effect by January 1, 2018. The proposed method would specify that allowances that remain unsold for more than 24 months would be transferred to the Reserve.

The staff is also proposing to collapse the current three tier prices of the existing Reserve into a single tier and to offer allowances from that tier at each Reserve sale at a single price, which would be the sum of Auction Reserve Price used at the auction plus \$60.

Gaz Métro's comments

The current Regulation seeks to put up for resale part (25%) of the allowances unsold at an auction after two auctions where the final price will have been higher than the floor price.

The transfer of allowances unsold after 24 months to the Reserve could reduce the amount of allowances available on the WCI market. This decrease in supply in California could increase the price of allowances for all members of the WCI market, including Québec-based members because the Quebec market is linked to the California market.

Having allowances not sold at an auction could be the result of a temporary drop in demand for allowances caused by the positive effects of GHG emission projects. A temporary drop in demand could also be due to the uncertainty surrounding the suit against the California carbon market for the post-2020 period.

However, demand for allowances could rise in the coming years, if, for example, there is growth in economic activity. At that point, unsold allowances could find a buyer at an auction taking place after the proposed 24 months period.

In such a situation, Gaz Métro believes that the transfer of unsold units to the Reserve could have a significant impact on the price of allowances, particularly since the drop in demand could be only temporary and disappear in the medium term, beyond the 24-month period...

Gaz Métro's recommendations

Gaz Métro recommends not modifying the current Regulation's provisions about the reintroduction of unsold allowances in the market.

However, if the Regulation were to be amended to introduce the possibility of transferring unsold allowances to the Reserve, Gaz Métro recommends that only 50% of any unsold volume be transferred to the Reserve and that this transfer be made only after 36 months. (GAZMETRO)

Comment:

Allowance Price Containment Reserve (APCR) Design Increases Costs and Decreases Liquidity Conflicting with ARB's Objectives

A new proposed provision allows ARB to transfer unsold allowances from the Current Auction, if unsold for 24 months after their initial sale date, to be transferred to the APCR and made available through a Reserve Sale. This process would come into effect January 1, 2018.

ARB's proposed method of continuing allowance diversions from annual budgets and proposing to funnel unsold allowances into the APCR is concerning.

Artificially raising costs conflicts with AB 32's statutory objective to develop market mechanisms as cost-effectively as possible. It could lead to a very large APCR

decreasing liquidity in the overall market. ARB's stated desire to increase market liquidity (ISOR Executive Summary, pp. 7) conflicts with the APCR changes. ARB should continue to return unsold allowances to the auction. (CCPC)

Comment:

Another suggestion we have is that we're concerned about the proposed provision to transfer unsold allowances into the APCR. We believe this could lead to a very large APCR, which would decrease liquidity in the overall market. And so ARB should continue to return unsold allowances back to the auction. (CCPC2)

Comment:

We do face a steep decline to 2030, and we urge that the Board reconsider the staff changes that would tighten the market, and would increase cost to industry over time, because we see that steep decline as making us face a serious challenge. This will happen because of the funneling of unsold allowances to the APCR, and also by taking part of the cap to the APCR.

I would remind the Board that in the past when we did an APCR, we actually increased the amount of offsets that industry was allowed to use. We just believe that these are premature changes given the steep decline we face in the future. (CHEVRON)

Response: Staff understands the commenters' concerns regarding moving unsold allowances from ARB's Auction Holding Account starting January 1, 2018. However, the transfer of unsold allowances to the Reserve would not reduce market supply or liquidity because those allowances are not on the market, they have never left the auction holding account. Indeed, they cannot be transferred to the Reserve until participants at eight auctions indicate that they are not needed by the market. Those allowances still would be made available for sale but at the Reserve tier price.

Further, staff have proposed revisions to retire a portion of unsold allowances in the first 15-Day Modifications Package to the Regulation to address outstanding emissions not fully attributed to participants in CAISO's Energy Imbalance Market. Retiring these allowances instead of transferring them to the Reserve allows staff to avoid retiring allowances directly from the annual allowance budget. Retiring allowances directly from the annual allowance budget would immediately reduce the supply of allowances to the market. This would have a more immediate effect on market prices than a transfer of unsold allowances to the Reserve.

Finally, the comment refers to the initial creation of the Reserve and the fact that ARB created the Reserve and increased the offset use limit simultaneously. However, staff does not view the augmentation of the Reserve as tightening the market. Since emissions have been below the cap in the initial years of the

program, staff concluded that the post-2020 cap should reflect this decline as well as the need to augment the Reserve.

Delaying Moving Unused 2020 Allowances to the APCR

H-3.3. Comment:

The Proposed Regulation Order also seeks to place allowances that have been unsold for eight consecutive auctions into the APCR. While we recognize the scrutiny that recent undersubscribed auctions have drawn to the program, MID cautions against prematurely removing allowances from circulation at lower prices and constricting the carbon market with low supply in the future. MID recommends extending the period of time stated in the Proposed Regulation Order before an unsold allowance is transferred to the APCR from eight consecutive auctions to twelve. This would ensure that short term market events are allowed to stabilize before action is taken to reduce the amount of allowances available to the market through the auction process. (MODESTOID)

Response: Staff understands the commenters' concerns that moving unsold allowances from ARB's Auction Holding Account starting January 1, 2018 may be premature based current market conditions. However, the transfer of unsold allowances to the Reserve would not reduce market supply or liquidity because those allowances are not on the market, they have never left the auction holding account. Indeed, they cannot be transferred to the Reserve until participants at eight auctions indicate that they are not needed by the market. Those allowances still would be made available for sale but at the APCR price. The commenter has requested changing the timing from 24 months to 36 months, to effectively further delay any transfer. ARB appreciates the comment, but believes that 24 months will be sufficient to assess short versus longer term market conditions.

Clarifying Availability of Unsold Allowances Transferred to APCR

H-3.4. Comment:

Treatment of Unsold Allowances. SCPPA appreciates staff's proposal that unsold state-owned allowances could be transferred to the Allowance Price Containment Reserve, as a potential means to address cost containment concerns and to address oversupply concerns beginning in 2018. We generally support the proposed methodology specifying that allowances that remain unsold for over 24 months would be transferred to the APCR, but seek further clarification on how to structure access to unsold allowances in a reasonable manner and timeframe. SCPPA would support ARB's use of unsold allowances to fund the continuation of the Voluntary Renewable Energy Program.

Potentially requiring the completion of eight auctions before the APCR transfer could be effectuated, without simultaneously clarifying that those allowances will remain there until sold, could reduce the effectiveness of the APCR's intent. SCPPA seeks

clarification that these allowances will remain available until they are sold. Given the legal uncertainty currently associated with California's Cap-and-Trade Program – which may not be resolved through the judicial system for quite some time – SCPPA is concerned that limiting administrative flexibility will place undue and premature pressure on the market. (SCPPA)

Response: Please see the response to comments H-3.2 and H-3.3.

Moving Unsold Allowances to Lowest Price Tier

H-3.5. Comment:

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. (PG&E)

Response: See response to 45-day comments H-4.5 and H-4.6.

Adding a Lower Price Tier for Unsold Allowances Moved to APCR

H-3.6. Comment:

ARB has proposed significantly modifying the structure and pricing of the APCR. Developing and implementing a program structure that will promote a robust market, with strong participation and liquidity, is of paramount importance to the long-term health of California's Cap-and-Trade program. The alignment of California's adjusted cap with forecasted 2020 emissions, with allocation of the surplus allowances to the APCR, will produce a balanced market over time – this will help promote liquidity, while driving trading and a meaningful price signal. Pairing this structural change with the transfer of unsold allowances to the APCR, after two years, should facilitate this movement to a balanced market, transitioning oversupplied allowances out of the market while providing a buffer for future needs.

However, we caution ARB on implementing design features that could create short-term market pricing spikes due to an artificial undersupply of allowances driven by these structural changes. A lack of market participation for over relatively short period of time could lead to significant allotment of allowances into the APCR. These allowances may then be needed to meet short term market demands, with no ability to access volume again outside of tapping into the APCR, leading to a significant increase in market pricing over a relatively short period of time.

IETA recommends that ARB revisit the pricing structure for the APCR design, setting a separate, lower, price for the unsold allowances that are allocated to the APCR. A balance will need to be struck between a price signal that is strong enough to incent continued, and hopefully growing, market participation while not leading to aggressive pricing spikes that could harm the integrity of California's overall Cap-and-Trade program. IETA believes this balance could be found with an APCR for unsold allowances priced at the floor + USD \$15, sending the appropriate signal to the market. (IETA)

Response: Staff disagrees with the analysis underlying the first part of the comment. Allowances could not be transferred to the Reserve until they have remained unsold in the Auction Holding Account for two years (or eight auctions.) This period is significantly longer than a "relatively short period of time." Comparing recent years' emissions with allowance budgets and offsets supplies, as well as recent auction results, ARB staff is not convinced the market would reverse itself very quickly so as to create a price spike anytime soon.

Staff agrees with the underlying idea of the second recommendation that "A balance will need to be struck between a price signal that is strong enough to incent continued, and hopefully growing, market participation while not leading to aggressive pricing spikes that could harm the integrity of California's overall Cap-and-Trade program." ARB staff believes the amendments strike that balance and is committed to monitoring and making adjustments as necessary.

Finally, as part of the 15-day amendments to the rulemaking, and consistent with the description in the ISOR of finding a solution to unreported CAISO Energy Imbalance Market-related emissions, staff has also proposed to use some of the unsold allowances to cover emissions from the CAISO Energy Imbalance Market that are not assigned to individual entities, instead of directly reducing annual allowance budgets to cover the unassigned emissions. This alternative use may supplant redirection to the Reserve.

Reissuing Unsold Allowances in Three Years Rather than Transferring to APCR

H-3.7. Comment:

SMUD suggests that rather than placing these unsold allowances in the APCR, the ARB simply "re-vintage" them to be placed back in the market three years after they have remained unsold (e.g. changing an allowance with a 2016 vintage to one considered as having a 2021 vintage). The re-vintaged allowances can either remain in the market, and made fully available for appropriate advance auction or be removed by ARB and made available as part of the 10% allocation normally included from a vintage in the advance auction. Either way, the allowances remain part of the normal Cap-and-Trade marketplace and are available at normal market prices upon reentry. This should address conditions of oversupply in one period while still including the expected amount

of allowances available in subsequent periods when such oversupply has potentially reversed, and market demand supports the supply of allowances. (SMUD)

Response: Nothing in the current regulation, or in the proposed amendments, would allow staff to “re-vintage” allowances once they have been issued. As described further in response to 45-day comment H-3.2, the transfer of unsold allowances to the Reserve would not reduce market supply or liquidity because those allowances are not on the market, they have never left the auction holding account. Indeed, they cannot be transferred to the Reserve until participants at eight auctions indicate that they are not needed by the market. Those allowances still would be made available for sale but at the APCR price. ARB staff believes this appropriately addresses oversupply concerns, and declines to make the changes requested by the commenter.

Cancelling Unsold Allowances Rather Than Transferring to APCR

H-3.8. Comment:

Cancel unsold allowances at the end of 2020 rather than placing them into the allowance price containment reserve (APCR), in order to increase policy stringency. Allowing covered entities to bank surplus allowances from the pre-2020 phase into post-2020 compliance periods will discourage early investment in emission reduction technologies that will be key to accomplishing the 2030 and longer-term goals. Allowing banking of oversupplied pre-2020 allowances into the post-2020 period also reduces the environmental integrity of the policy...

Cancel unsold allowances at the end of 2020, rather than placing them into the allowance price containment reserve (APCR), in order to increase policy stringency and environmental integrity.

ARB has proposed placing allowances that are left unsold after 24 months into the APCR, most likely for use in post-2020 compliance periods.⁴²⁵ We believe these allowances should be retired at the end of 2020, rather than placed into the APCR. The over-allocation of allowances in the current period is due to a number of factors—most notably much lower than forecast electricity demand and economic growth, high reliance on complementary policies, and resource shuffling in the electricity sector, all of which decrease demand for allowances. Yet the ISOR is silent on why the detrimental effects of the present oversupply condition should be carried forward into future compliance periods.

One reason may be to increase demand for unsold allowances during the pre-2020 compliance periods, which would lead to more revenue in the near term for the Greenhouse Gas Reduction Fund (GGRF). This would occur because significant volumes of allowances are not selling out at auctions at the current year’s price floor of

⁴²⁵ ISOR at 16-17.

\$12.73 per tCO₂e—over 120 mmtCO₂e so far in 2016 alone.⁴²⁶ Under ARB’s proposal, unsold allowances would eventually be placed in the APCR, where they would become available for purchase at the auction reserve price plus \$60 per tCO₂e.⁴²⁷ As a result, covered entities that are confident in the market’s future would have an incentive to purchase surplus allowances not needed in the pre-2020 period in order to avoid significantly higher-than-inflation costs in the post-2020 period.

While resources for the GGRF are important for fully funding emission reduction programs that complement the cap-and-trade, raising GGRF revenue by allowing arbitrage across compliance periods creates serious risks for the post-2020 program. Just as ARB’s proposal will raise demand now, so too will it decrease demand—and therefore prices—later. Particularly when combined with the proposal’s already too-high cap (see Part 1, above), this will increase the risk that inadequate price signals emerge in the first part of the post-2020 period, compared to what is needed to drive the transformational investments required to achieve the 2030 target. If low prices reduce low-emission infrastructure investments in the early years, ARB’s program design may lead to policy risk in the later years, at which point covered sources could argue that the 2030 target had become unachievable in practice. Simply put, a system designed for artificially low prices puts the ambitious 2030 target at risk.

To mitigate this risk, we urge ARB to cancel unsold and unused allowances at the end of 2020 so that forecast errors made (and policy interactions not fully anticipated) in the early program design phase do not ease the stringency of the of the post-2020 compliance periods. Low carbon prices during this critical transition period would send exactly the wrong message to covered entities. ARB should therefore consider revoking covered entities’ ability to bank pre-2020 allowances for post2020 compliance. Alternatively, ARB could take a more dynamic approach to alleviating oversupply, cancelling allowances left unused or unsold that have vintages older than the previous compliance period. For example, all pre-2018 allowances left unused or unsold in would be cancelled in 2021; in 2023, all pre-2020 allowances left unused or unsold would likewise be cancelled.

We also note that other over-allocated cap-and-trade programs—such as the European Emission Trading System (EU ETS)—have confronted similar challenges. When it became clear that Phase I of the EU ETS was over-allocated, that problem was self-contained because banking was not allowed between Phases I and II.⁴²⁸ Similarly, when EU regulators observed that the use of Clean Development Mechanism (CDM)

⁴²⁶ ARB, California Cap-and-Trade Program Summary of Joint Auction Settlement Prices and Results (August 2016), available at https://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

⁴²⁷ ISOR at 16-17.

⁴²⁸ A. Denny Ellerman, Claudio Marcantonini, and Aleksander Zaklan, The European Union Emissions Trading System: Ten Years and Counting, *Review of Environmental Economics and Policy* 10(1): 89–107.

offsets had been problematic from an environmental integrity perspective, the EU banned the use of HFC credits from the CDM in Phase III.⁴²⁹ We suggest that the problems facing ARB's market at present resemble these challenges and call for similar responses.

Whatever ARB does, we urge it to consider that credible expectation of relatively high carbon prices in the 4th compliance period (2021-2023) will be an essential signal to investors and firms that must make the reductions needed to achieve the 2030 target. In our view, this issue is much more important than fully funding the GGRF in the near term.

Finally, we note that if ARB prefers to focus on the environmental attributes of the cap-and-trade program—as opposed to its role in developing a credible post-2020 carbon price trajectory—then the environmental integrity consequences of the proposed rule also require more attention. Oversupply in the current market is due, in part, to leakage from resource shuffling in the electricity sector.⁴³⁰ Importing these impacts from the pre-2020 period into the post-2020 period would reduce the environmental integrity of the post-2020 program while depressing the market's critical price signal. (WARA)

Response: The commenter recommends that ARB retire unsold allowances by 2020. The request is outside of the scope of this rulemaking. Further, drastic changes to the program that would impact expected supplies of compliance instruments and target specific vintages must be carefully evaluated to understand any unintentional impacts, such as driving market behavior, implications for prices in the near and long-term, and potential adverse impacts to linked markets. The commenter does not provide any such analysis of these potential impacts for staff's evaluation.

ARB Discretion Over Disposition of Consigned Allowances

H-3.9. Comment:

Section 95910. Auction of GHG Allowances

ARB is proposing to revise its authority to auction those allowances that have been consigned to it. ARB had previously been required to auction allowances; however, ARB's proposed revision would give it discretion to do so.⁴³¹ LADWP believes that this change could permit ARB to not auction allowances that have been consigned to it for that purpose, at its discretion, without any standards for deciding when to exercise this discretion.

⁴²⁹ Id.

⁴³⁰ Cullenward (2014a), supra note 13 (reviewing early observed resource shuffling transactions and comparing projections of total resource shuffling potential against cumulative expected market reductions).

⁴³¹ 2016 1SOR Appendix A at 234 (proposed § 95910(c)(1)(C).

To the extent that ARB is concerned with its authority to auction allowances from closed accounts,⁴³² it should do so by explicitly adding this authority rather than removing the non-discretionary duty to auction all allowances consigned to the current auction. (LADWP)

Response: ARB staff believes the proposed language maintains existing authority necessary to account for allowances that may be consigned from suspended or revoked accounts as referenced in section 95910(d). ARB has not revised its authority to auction allowances consigned to an entity's limited use holding account. Further, staff has proposed amendments under the second 15-Day Public Notice to clarify that allowances from closed accounts may be consigned or administratively transferred pursuant to section 95835(f) or 95890(k).

H-4. Allowance Price Containment Reserve (APCR)

Opposition to Collapsing Current Price Tiers

H-4.1. Multiple Comments:

ARB Should Carefully Consider Its Proposal to Collapse the APCR Tiers Into a Single Tier

Calpine supports ARB's proposal to eliminate the automatic annual five percent increase from the APCR in lieu of a simple inflation adjustment. Under the existing framework, the difference between containment prices and the floor price continues to expand with each annual adjustment, which may reduce the APCR's containing function. Calpine is also generally supportive of ARB's proposal to align the APCR with linked jurisdictions, thereby limiting the potential for arbitrage should participation in APCR sales be necessary in the future.

Calpine also generally agrees with ARB that it may be appropriate to collapse the APCR into a single tier. However, coupled with ARB's proposal to shift chronically unsold allowances to the APCR, collapsing the tiers could lead to unintended consequences as program risks are resolved and the market rebounds. Although the market has no direct experience with how the three tiers might function to mitigate volatility due to the absence of any reserve sales to-date, it is possible that the three-tiered framework could, by providing a staged series of safety valves, better moderate any rapid increases in allowance prices. Calpine therefore encourages ARB to conduct additional modeling or analysis to compare the potential impacts of moving from the existing three-tiered framework to a single tier and assure that the change would not unduly restrict the containment function of the APCR. While Calpine is generally supportive of jurisdictional alignment of the APCR tiers, ARB should also further evaluate whether

⁴³² 2016 ISOR at 213

alignment of the highest tier would sufficiently limit opportunities for arbitrage (CALPINE)

Comment:

CMCA's major concern with the proposed regulatory changes is maintaining the balance between: 1) solving the current supply and demand imbalances that have resulted in auctions with low subscription rates and large numbers of allowances being put into the Auction Holding Account ("AHA"), and 2) avoiding setting up the market for a possible shortage in the longer term. CARB's proposed regulations aim to solve the short-term oversupply by transferring unsold allowances to the Allowance Price Containment Reserve ("APCR") as referenced in section 95911, subsection (g) of the proposed regulations. While CMCA agrees with CARB that the surplus unsold allowances should be removed from the AHA and put into the APCR, CMCA is worried that when combined with other proposed regulatory changes and developments in the legal/legislative arena, CARB risks significant price volatility and potential price spikes in the future.

CMCA would note that the current lack of demand in the auctions, is the result of oversupply, which may reach as high as 300 Million tons by CMCA's estimates and also is from the significant uncertainty in the future of the cap and trade program. This uncertainty results from the Cal Chamber lawsuit and the lack of an explicit reauthorization of cap and trade by a two thirds majority vote of the California legislature. It is quite conceivable that this uncertainty could remain an issue through 2018 further dampening demand.

CMCA is concerned that once such uncertainty is resolved, pent up demand could be pulled forward as market participants suddenly start to hedge post 2020 obligations. At the same time proposed regulations have the potential to reduce future supply, increase future demand, and increases the risk that allowance auction prices will jump from the auction reserve prices to the APCR reserve price of approximately \$60 in 2020, a 4-fold increase. In order to protect against this type of destructive and politically untenable upwards price volatility, CMCA makes the following recommendations to CARB:

1) Not eliminating the price tiers as is currently being proposed by CARB.

a) Once demand outstrips allowances supplied through the auction and secondary market, the currently proposed one price tier at a \$60 price adder to the Auction Reserve Price for reserve allowances risks causing prices to quickly jump to \$75+ per allowance. Such a dramatic and possibly quick price spike risks destabilizing the market and the public's trust in the viability of the cap and trade program because the impact of such high prices on the economy and consumer prices could be damaging and reminiscent of the California Power Crisis in 1999-2000.

b) CMCA has completed an analysis that shows that as much as 200 million tons of unsold allowances could eventually be transferred from the AHA to the APCR by 2020.

Combined with the volumes already budgeted for the APCR, the enlarged APCR coupled with multiple price tiers, could provide a valuable mechanism to slow or moderate upwards price volatility and, in essence, provide a series of “speed bumps” to market prices. (CMCA)

Comment:

Recommend Maintaining Three Price Tiers- SoCalGas is concerned that collapsing the existing three reserve-price tiers to one will increase the chances of extreme price spikes and price volatility in the linked California and Quebec Cap- and-Trade carbon market. The risk for this market behavior is heightened when combined with the proposal to remove surplus unsold allowances from the Auction Holding Account (AHA) and transferring them to the Auction Price Containment Reserve (APCR), starting in 2018. The result could be very costly to compliance entities and damaging to utility ratepayers. The Carbon Market Compliance Association completed an analysis that found as many as 250 million unsold allowances could be transferred from the AHA to the APCR by 2020.

We are in agreement that transferring unsold allowances to the APCR is a positive change when considered as a stand-alone measure, but could be de-stabilizing to the market when considered with a single-tier framework. SoCalGas also sees the virtue in modifying the pricing mechanism to establish a fixed price difference in real dollars between the Auction Reserve Price and Reserve Sale Price. But, we recommend having at least three tiers of reserves at a certain percentage over the price floor which would allow the market to more smoothly transition to higher prices and would also allow reserve prices to keep pace with inflation while not widening the gap over time as was noted as a concern by ARB. (SOCALGAS2)

Response: ARB staff appreciates the commenters’ general support for collapsing the APCR into a single reserve tier and the proposed mechanism to address unsold allowances from the auction holding account. Staff believes that the proposed changes to the APCR simplify Reserve sale operations while still maintaining an adequate cost containment design that does not unduly tighten the market. To date, no Reserve sales have been held and no reserve allowances sold. Staff expects the APCR to hold over 120 million allowances from the first three compliance periods at the start of 2021, and staff believes that this quantity along with the allowances allocated to the APCR from 2021 to 2031 is sufficient to meet the cost containment needs of the Program over this time. Staff also notes that with the recent enactment of AB 398, the Legislature has provided additional direction for the post-2020 period with respect to establishing two price containment points at levels below the price ceiling. ARB will initiate a new rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

H-4.2. Comment:

The proposed restructuring of the program (1) increases costs through the APCR changes, (2) are unnecessary and, (3) complicate what should be a streamlined and effective program. Many of the proposed changes tighten the allowance market which is unnecessary, particularly in light of legal uncertainty around the program which is artificially depressing prices. These restructuring proposals are contrary to the statute itself which requires a cost effective approach. They are also premature attempts to control short term variation in the market and auction subscription after only one compliance period under the shortest and shallowest cap. (CCEEB)

Response: Staff disagrees with the comment. The proposed collapse of the Reserve to a single tier greatly simplifies the process of purchasing from the Reserve and avoids strategic bidding issues that were associated with the current “roll down” bidding process. The proposed changes would signal to the market that any pool of unsold allowances should be viewed as temporary, and auction bidding should be determined by entities’ abatement costs not the accidental accumulation of allowances in the Auction Holding Account.

Increasing Reserve Price and APCR Prices Based on Modelling

H-4.3. Comment:

Provide a reasoned basis for the post-2020 auction reserve price and the trigger price of the allowance price containment reserve (APCR). At present neither price is anchored to any scientific or economic rationale. We suggest tying these prices to the federal Social Cost of Carbon and/or to economic modeling that estimates high and low carbon prices necessary to achieve the 2030 statewide emissions limit, based on a reasonable consideration of economic and energy forecasting uncertainty...

Ground the Auction Reserve Price and the Allowance Price Containment Reserve (APCR) trigger price in a science- and economics-based justification.

As the Board and Staff are well aware, the Auction Reserve Price has been a critical design feature of the cap-and-trade program in the first two compliance periods. Given the ambition of the post-2020 program, and the surplus of allowances likely to be carried forward from the pre-2020 program under ARB’s proposal,⁴³³ it is likely that either the Auction Reserve Price, the APCR trigger price, or both will again dominate post-2020 market behavior. It is therefore striking that the value for the Auction Reserve Price (and perhaps the values for the APCR reserve prices as well) were chosen somewhat arbitrarily when first proposed.

⁴³³ Id. at 13 (stating Staff’s expectation that the APCR will hold “over 120 million allowances at the start of 2021”).

Very low allowance prices are a remarkably common characteristic of cap-and-trade regimes, as we⁴³⁴ and others⁴³⁵ have noted. In particular, Borenstein et al. suggest that the California cap-and-trade market design will tend to produce allowance market outcomes that rest either at the price floor or at (or above) the APCR trigger price, but not in between—in no small part because the market is paired with strong complimentary measures. Although their analyses concern the pre-2020 period, there is reason to think that the conclusions will be just as relevant to the post-2020 period. After all, ARB is contemplating a post-2020 climate policy portfolio that is dominated by complementary policies, just as was the case with the pre-2020 policy portfolio.⁴³⁶

We note with interest the changes that ARB has made to the APCR trigger price for the post-2020 period. ARB has proposed removing the tiered prices at \$40, \$45, and \$50 per allowance and replacing them with a single price level that is \$60 above the auction reserve price, which continues to rise at 5% plus CPI per year as before.⁴³⁷ Given what we have learned about the current program, and hence the APCR trigger price's likely importance to the performance of the post-2020 program, we believe that much more reasoning and justification should be provided for both the level of the auction reserve price and the APCR trigger price. The current arrangement seems arbitrary in that it is largely a path dependent result of design choices made in the original rule making. Since the APCR's reserve price is subject to modification in the current rule amendment, we believe that ARB should consider modifying the auction reserve price and taking the opportunity to provide a more reasoned basis for both the auction and APCR reserve prices.

Again, the current cap-and-trade market has operated at or very near or the auction reserve price for much of the program's existence.⁴³⁸ Thus, it would seem wise to

⁴³⁴ Michael Wara, *Instrument Choice, Carbon Emissions, and Information*, Michigan Environmental and Energy Law Review 4(2): 261–301 (2015); Michael Wara, Danny Cullenward, and Rachel Teitelbaum, *Peak Electricity and the Clean Power Plan*, The Electricity Journal 28(4): 18–27 (2015); Danny Cullenward, *Leakage in California's Carbon Market*, The Electricity Journal 27(9): 36–48 (2014a); Danny Cullenward, *How California's carbon market actually works*, Bulletin of the Atomic Scientists 70(5): 35–44 (2014b).

⁴³⁵ Severin Borenstein, James Bushnell, Frank Wolak, and Matthew Zaragoza-Watkins, *Report of the Market Simulation Group on Competitive Supply/Demand Balance in the California Allowance Market and the Potential for Market Manipulation*, Energy Institute at Haas Working Paper #251 (July 2014); Severin Borenstein, James Bushnell, Frank Wolak, and Matthew Zaragoza-Watkins, *Expecting the Unexpected: Emissions Uncertainty and Environmental Market Design*, Energy Institute at Haas Working Paper #274 (August, 2016).

⁴³⁶ ISOR at 313 (citing the PATHWAYS modeling results, which project cumulative emission reduction requirements over 2021 to 2030 of ~900 mmtCO₂e—700 to 800 mmtCO₂e of which are discussed as coming from complementary policies, leaving 100 to 200 mmtCO₂e from the cap-and-trade program); see also ARB, *2030 Target Scoping Plan Update Concept Paper* (June 17, 2016) at 21-23 (describing ARB's vision for Concept 1: Complementary Policies with a Cap-and-Trade Program).

⁴³⁷ ISOR at 14-15.

⁴³⁸ Danny Cullenward and Andy Coghlan, *Structural oversupply and credibility in California's carbon market*, The Electricity Journal 29(5): 7–14 (2016); see also CPI, *California Carbon Dashboard*, <http://calcarbodash.org/>.

reconsider whether the originally selected price floor—\$10 plus CPI plus five percent⁴³⁹—is optimal in light of the state’s 2030 target. But there is no discussion or analysis in the ISOR of whether the price floor continues to be the appropriate minimum value sufficient to accomplish the climate objectives or increase the credibility of the market signal that ARB wants to transmit.

We have two suggestions for how to better ground these numbers in credible, scientific analysis.

First, ARB could adopt the mid-range federal Social Cost of Carbon (SCC) estimate as the auction reserve price—\$42 per tCO₂e in 2020, rising to \$50 in 2030.⁴⁴⁰ This would provide a scientific basis, however imperfect, for the minimum market price. It would guarantee that in the event macroeconomic forecasting errors and complementary policy interactions result in a lack of stringency in the cap-and-trade program, emitters at least face an obligation to incorporate the U.S. government’s best estimate of the present value of damages from their emissions.

Along similar lines, ARB could simultaneously adopt the high-end value proposed in the SCC update for the APCR price trigger—\$123 per tCO₂e in 2020, rising to \$152 in 2030.⁴⁴¹ While resulting in a greater range than the \$60 price spread between the effective price floor and ceiling proposed in the draft rule, our suggested APCR trigger values are grounded in a rationale for placing a maximum value on the price that entities in California pay to emit carbon—one that is representative of the tail risk for climate sensitivity across the probabilistic distributions in the most recent SCC estimate. Under our proposal, covered sources in California would not pay more for climate mitigation than the discounted value of damages from a high-climate-sensitivity warming scenario.⁴⁴² If ARB adopts this recommendation, the Board should also consider including a mechanism to automatically review any updates to the federal SCC for potential adoption in the cap-and-trade program.

A second alternative would be to undertake a modeling exercise using an economic model similar to that in Borenstein et al.⁴⁴³ to determine the best- and worst-case price trajectories necessary to accomplish the SB 32 goals under a wide range of economic, policy, and technological assumptions. After completion of the exercise, ARB could set the auction reserve price and the APCR price trigger at these values, or, if the modeling included a sufficient number of scenarios to generate confidence intervals, at the upper and lower 95% confidence limits for marginal abatement cost (thus excluding extreme

⁴³⁹ Cal. Code Regs. tit. 17, § 95911(c). ARB’s proposal would not change this structure. ISOR at 15.

⁴⁴⁰ Interagency Working Group on the Social Cost of Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866 (May 2013, Revised July 2015) (reporting the 3.0% discount rate SCC estimates, which are denominated in constant 2007 USD), available at <https://www3.epa.gov/climatechange/EPAactivities/economics/scc.html>.

⁴⁴¹ Id. (reporting the 3.0% discount rate and upper 95% confidence interval climate sensitivity SCC estimates, using constant 2007 USD).

⁴⁴² Assuming sufficient allowance supplies are available in the APCR.

⁴⁴³ Borenstein et al. (2016), *supra* note 14.

outlier scenarios). We note that this approach would require additional analytical work, but would achieve the highest certainty and reliability for establishing the program's most critical parameters.

Real world experience in multiple cap-and-trade markets, our previous scholarship, and scholarship from others working on California's climate policy demonstrates that the market is very likely to reside at either the auction reserve price or the APCR price. This characteristic of the cap-and-trade market follows directly from its role as just one of multiple complimentary policies.⁴⁴⁴ Therefore it is critical that these market price points reflect science-based analysis, rather than arbitrary choices retained from the status quo system. At a minimum, ARB should provide a stronger rationale for the numbers it selects for these critical set points in the market design than is provided currently in the ISOR. (WARA)

Response: Since ARB did not propose modifications to the Auction Reserve Price methodology, that portion of the comment is outside the scope of this rulemaking. ARB staff believes the suggested revisions contained in the comment are more appropriate for configuring a carbon tax than a carbon cap-and-trade system. Notwithstanding this, ARB staff set the initial Auction Reserve Price with the objectives of supporting a minimum level of investment in direct reductions by emitters as well as in offset projects. While prices have remained near the Auction Reserve Price, the price has been sufficient to support offset production and to contribute to keeping emissions under the cap.

The comment recommends setting the Auction Reserve Price as the mid-range federal Social Cost of Carbon estimate, which is \$42. The current system has accumulated unsold allowances at a value much lower than the suggested value. In fact, at no time have prices for California carbon allowances ever approached the suggested figure. The economic analysis proffered by the commenter in support of the suggested modifications would suggest that prices could rise into that range after 2020. Until such a price increase occurs, which may be well after the time suggested by the comment, using the value recommended by the commenter would clearly lead to the Auction Reserve Price binding at every auction and the cap-and-trade mechanism would function more like a carbon tax.

ARB staff notes that in developing the Auction Reserve Price, ARB sought to ensure a cost-effective approach, looking at the cost of abatement; as opposed to the Social Cost of Carbon, which looks instead at a cost range related to damages caused by emissions. ARB's approach must comply with AB 32, which provides that ARB may adopt "a system of market-based

⁴⁴⁴ Michael Wara, California's Energy and Climate Policy: A Full Plate, But Perhaps Not a Model Policy, *Bulletin of the Atomic Scientists* 70(5): 26–34 (2014).

declining annual aggregate emissions limits” when such a system can “achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions” (Health & Safety Code §38562(c)). California has met or been below the aggregate emissions limits each year of the Cap-and-Trade Program’s operation. Since the level of the recommended price (\$42) would be well above historical and currently prevailing market prices, the recommended price could not be considered cost-effective compared with the Program’s current Auction Reserve Price Methodology.

The comment is correct in suggesting that the Reserve tier prices were not set using a purely “scientific” method. The process of selecting the 2013-2020 tier prices is outlined in the 2010 ISOR and FSOR, as well as in Appendix G of the 2010 ISOR, and ARB staff has proposed to essentially continue that rationale (with a collapse to a single tier) as part of this rulemaking. During the initial design phases of the regulation, ARB grappled with the tradeoff between the need to restrain price increases to socially acceptable levels and the desire to avoid undue interference in the market. Stakeholders that were primarily concerned with achieving maximum emissions reductions or avoiding interference with the market mechanism argued, like the commenter, for much higher Reserve prices. Other stakeholders were more concerned with leakage, in which California emissions decrease because California economic output is replaced by imports from other jurisdictions without carbon pricing, so that there is no decrease in the emissions for which Californians are responsible for causing. These stakeholders argued for lower Reserve tier prices. Thus, the resulting top Reserve tier price (initially \$50) was a policy decision that dealt with this tradeoff. ARB staff also notes that AB 32 provides the Governor with an ability to intervene in any market mechanism if prices are deemed too high. Thus, the statute recognizes that there may be a level beyond which the public is not willing to pay for such reductions.

As indicated above, comments regarding modifications to the auction reserve price are also outside of the scope of the proposed regulatory amendments. ARB staff is dedicated to continuing to monitor market price points for both the auction and cost containment market design features, but declines to make the requested change to the auction reserve price. See also response to 45-day comment H-4.1, specifically with respect to Legislative direction in AB 398.

Reducing Price of Lower Tiers

H-4.4. Comment:

I'd like to, first of all, say that we support CARB's proposed regulatory changes, and specifically the proposal to put the unsold allowances into the APCR.

We understand the comments that have been made in writing and in person today about the concerns about that proposal. We have believe that CARB could address

those concerns by maintaining the current price -- 3 price tiers in the APCR, and expanding the gap between the price tiers from \$5 to \$15 or maybe even \$20 with the lower price tier starting below the current APCR price.

An enlarged PCA populated by the unsold allowances will serve as valuable commodity and price mitigation tool to slow down any drastic upward price volatility.

Due to the success of the current regulations and the complimentary measures, California does not have enough fast-acting carbon -- available carbon emission reductions at prices below the APCR that could slow or quickly react to higher prices. And an enlarged and expanded APCR with 3 tiers would do that.

In essence, the enlarged APCR with a wider range of price tiers would create speed bumps that should, if the market prices rose in the future, would allow volatility to be mitigated.

CMCA supports CARB's proposal to move on sole allowances that remain in the holding account and believes that this mechanism will add to the environmental integrity, and bring confidence to the market. We estimate that as much as 250 million tons may go unsold over the next 2 years.

This potentially large volume of allowances is a real risk to the environmental integrity of the program, and also undermines and distorts the market. The unsold allowances in the holding account, in essence, create a new cap at the floor is what we call it. So 250 million tons, essentially twice the current price containment floor -- price containment reserve at the floor and we see that as very dangerous.

The market distortions brought on by the unsold allowances and failure of auctions to sell is damaging, and could also damage linkages to places like Ontario and others that are looking at this market as they see a potential lack of revenues and lack of unsold -- and lack of sold allowances, and so we support the CARB proposals. (CMCA2)

Response: ARB staff appreciates the commenter's support for the amendments, particularly the proposed mechanism for unsold allowances.

Staff disagrees with the comment that the existing three-tier structure of the Reserve should be retained. Staff believes the single price tier for post-2020 reserve sales is necessary to make administrative operations and the bid award determination process simpler for ARB and its contractors, as well as makes it easier for market participants to formulate a bidding strategy. The APCR serves as a cost containment mechanism to mitigate price volatility, and the proposed design change to a single tier price does not change the function of the APCR. Notwithstanding this, see also response to 45-day comment H-4.1, specifically with respect to Legislative direction in AB 398.

Reducing Price Range Among Tiers

H-4.5. Comment:

The current Regulation (Subarticle 10, § 95913) sets the price for reserve units according to three tiers:

- (A) Allowances from the first tier shall be offered for \$40 per allowance;
- (B) Allowances from the second tier shall be offered for \$45 per allowance; and
- (C) Allowances from the third tier shall be offered for \$50 per allowance.

The prices for the three tiers were set at the same time as the minimum initial price of allowances of US\$10 per unit.

Consequently, the original version of the Regulation provided for a gap of US\$35 between the effective floor price of US\$10 in 2013 and the average reserve unit price of US\$45...

Regarding the price variance between reserve units and the minimum auction price, Gaz Métro supports the proposal to set the variance at a predefined amount to keep that variance constant in the future. However, Gaz Métro recommends setting the variance at US\$35 instead of US\$60 to reflect the variance initially provided by the Regulation in 2013. (GAZMETRO)

Response: Staff appreciates the support to replace the scheduled increases in the reserve tier prices instead with a fixed price using the annual Auction Reserve Price and the last highest tier reserve sale price adjusted by the annual inflation rate. ARB conducted further review of the potential price trajectory of the highest tier price for 2021 and revised its proposal for determining the single Reserve Sale Price effective 2021 in the second 15-Day Modifications to the Regulation. In the initial 45-day notice package, the amount was fixed at \$60. Staff derived this number by forecasting the auction reserve price and highest tier price for 2021 and taking the difference. Upon further review, the provision was modified to remove the initially proposed \$60 fixed amount, and to instead establish the fixed dollar amount in 2021 using the auction reserve price and highest tier prices in force in 2020. This modification would avoid the possibility that the 2021 value could be very different from the 2020 realization, which could happen if the realized rates of inflation over the period are very different from the rates staff used in the original estimate. After 2021, the fixed dollar amount would still be increased each year by the rate of inflation. The proposed single Reserve Sale Price is set at the higher estimated reserve tier price to afford greater protection against depletion of the Reserve. Staff continues to believe this is the correct approach for cost-containment, and declines to incorporate the commenter's suggestion to use the lower tier price. See also response to 45-day comment H-4.1, specifically with respect to Legislative direction in AB 398.

Collapsing to Single Low-Price Tier

H-4.6. Multiple Comments:

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. (PG&E)

Comment:

Additionally, JUG members believe that collapsing the Allowance Price Containment Reserve can be workable, but offering allowances at what was previously the highest price tier would reduce access to lower cost allowances in the event of a price spike. JUG members propose that ARB utilize the difference in 2020 between the floor price and the previous lowest or middle APCR tier (rather than the highest price tier) as a starting point for determining the post-2020 APCR price. (JOINTUTILITIES)

Comment:

SMUD supports the components in the Proposed Amendments that add to and alter the APCR structure by:

- Collapsing the APCR from three Tiers at present into a single Tier, but tied to the lowest current APCR Tier price rather than the highest;
- and setting the single-Tier APCR price using a fixed, real, premium over the annual Auction Reserve, or floor price.

It is important to maintain and expand the APCR to afford continued market protection against significant price increases. If the APCR is ever accessed, injecting all of the allowances into the market at one price is likely to have a stronger stabilization effect than having three separate price tier "injections" (as the APCR is currently structured). (SMUD)

Comment:

Allowance Price Containment Reserve. We appreciate ARB staff's proposed revisions to the Allowance Price Containment Reserve (APCR), and its proposed 2021-2031 extension, in order to support cost containment efforts. We believe that this is consistent with current policies. This includes efforts to simplify and streamline the APCR by —collapsingll the existing three fixed-price, equal-sized tiers (which now includes a transitional 5% annual escalator plus a measure of the rate of consumer inflation) for reserve sales of any allowances. SCPPA notes that there is now a widening gap between existing allowance sales prices (generally at or near the —price floorll of just under \$13) and the proposed APCR allowances even under the 2016 offer prices (\$47.54 to \$59.43 between the three tiers) – which will only increase with escalators over time. Given this significant market differential – and the cost containment intent of the APCR itself – SCPPA urges ARB to reconsider setting a fixed arbitrary price of +\$60, which may actually undermine the intent of the reserve going forward by making allowance prices held in reserve inordinately expensive to address market fluctuations over the next 15 years. We recommend that staff consider a lesser amount that would endeavor to keep APCR prices more accessible for regulated entities as a means to ensure rate affordability for their customers. (SCPPA)

Comment:

Cost containment post-2020 must be well-designed and effective to avoid market disruption and cost shock to ratepayers. The Allowance Price Containment Reserve (APCR) is a valuable component of the Cap-and-Trade program. APCR helps ensure that, as economy-wide emissions approach the cap, that allowance prices remain reasonable while entities make investments or change their processes to further reduce their emissions. In the Proposed Regulation Order, ARB proposes several changes to the APCR for the post-2020 program. One such change would be to collapse the existing three-tier price structure of the APCR to a single price that would be equal to \$60 (adjusted annually for inflation) above the Auction Reserve price. MID supports the simplification of the APCR. However, it appears that the \$60 price difference is based on the existing highest price tier. MID recommends that the post-2020 APCR price instead be based on the lower or middle price tier. Using the difference from the higher price tier would make allowances available for use at a higher price than they would otherwise be, and would unnecessarily increase the cost impact to Californians should Cap-and-Trade covered entities need to access the APCR.

With cost to Californians in mind, MID suggests that ARB reevaluate the escalation rate of the Auction Reserve ("floor") price. The current rate of five percent plus inflation per year is too high, and guarantees high compliance costs as the program matures. Now that the carbon market has been established, it makes sense to allow the market to dictate the price of allowances rather than market participants chasing to keep up with the ever increasing floor price. As proposed, the floor price in 2030 would be roughly three times its current price of \$12.73 per allowance. (MODESTOID)

Response: Staff appreciates the commenters' support to modify the structure of the APCR to a single tier. The proposed single Reserve Sale Price is set at the higher estimated reserve tier price to afford greater protection against high market price spikes. ARB conducted further review of the potential price trajectory of the highest tier price for 2021 and revised its proposal for determining the single Reserve Sale Price effective 2021 in the second 15-Day Modifications to the Regulation. See response to 45-day comment H-4.6.

AB 32 provides the Governor with an ability to intervene in any market mechanism if prices are deemed too high. Thus, the statute recognizes that there may be a level beyond which the public is not willing to pay for such reductions.

In addition, during the initial design phases of the regulation, ARB grappled with the tradeoff between the need to restrain price increases to socially acceptable levels and the desire to avoid undue interference in the market. Stakeholders that were primarily concerned with achieving maximum emissions reductions or avoiding interference with the market mechanism argued, like the commenter, for much higher Reserve prices. Other stakeholders were more concerned with leakage, in which California emissions decrease because California economic output is replaced by imports from other jurisdictions without carbon pricing, so that there is no decrease in the emissions for which Californians are responsible for causing. These stakeholders argued for lower Reserve tier prices. Thus, the resulting top Reserve tier price (initially \$50), was a decision that attempted to resolve the tradeoff between what policy makers saw as the maximum Californians should have to pay for emissions reductions with the other objectives.

Comments regarding modifications to the auction reserve price are also outside of the scope of the proposed regulatory amendments. ARB staff is dedicated to continuing to monitor market price points for both the auction and cost containment market design features, but declines to make the requested change to the auction reserve price. See also response to 45-day comment H-4.1, specifically with respect to Legislative direction in AB 398.

Support for Allocating to APCR After 2020

H-4.7. Comment:

SMUD supports the components in the Proposed Amendments that add to and alter the APCR structure by:...

- Allocating after 2020 to APCR based on the comparison of expected actual versus capped emissions in 2020;

(SMUD)

Response: Thank you for the support.

Increasing Later Periods' APCR Allocation

H-4.8. Comment:

In Table 8-2, the Proposed Amendments set a declining allocation of allowances to the APCR from 2021 to 2031. However, the proposal would stop funding the APCR in 2029. Given that the allowance cap will continue to be tightened over the entire duration of the Program, it is more likely that compliance entities will need to rely on the APCR in those years. Despite the fact that the Program contemplates borrowing allowances from future compliance periods, NCPA encourages CARB to designate allowances in a sufficient quantity to ensure that the APCR continues to receive allowances through to the end of the period for which the current GHG budget is set. With the overlap between the CPP and the Program, it is especially important that compliance entities have assurances in the "out years" of the Program that they will have sufficient access to allowances for meeting their compliance obligations. (NCPA)

Response: Staff believes the number of allowances allocated to the Reserve after 2020, together with the carryover of the current Reserve and the existing provisions to replenish the Reserve with future vintage allowances is sufficient for the Reserve to meet any reasonable forecasted demand. As such, staff declines to make the change suggested by the commenter.

Opposition to Ceasing 4% Allocation to APCR

H-4.9. Multiple Comments:

Reconsider elimination of the 4% allowance allocation to the APCR. Alternatively, provide a reasoned justification for why circumstances now support preserving the 8% offset limit while eliminating the 4% APCR allowance allocation, which was established when the offset limit was increased from 4 to 8%...

Reconsider elimination of the 4% annual allowance allocation to the APCR, or provide a reasoned justification for why circumstances support preserving the 8% offset limit without the 4% APCR allocation in post-2020 compliance periods.

In its original proposal for a cap-and-trade program in California, ARB limited use of offsets to 4% of the annual allowance budget in any given year. In response to comments received on this proposal, ARB doubled the percentage of offsets that entities may use for compliance purposes to 8% of the annual allowance budget. At the same time, and in order to balance this extra provision of cost-containment, ARB

created the APCR and placed 4% of each year's allowance budget into it in order to insure that cap stringency was maintained despite the additional supply of offsets.⁴⁴⁵

In the current proposed amendments to the cap-and-trade, ARB is proposing to phase down the 4% allowance allocation to the APCR with no change to the limitation on use of offsets for compliance purposes.⁴⁴⁶ There is no discussion of the reasoning behind this change other than that in Staff's opinion, supply to the APCR will be "sufficient to meet cost containment needs of the program."⁴⁴⁷

We ask for greater reasoned justification in the ISOR for eliminating the 4% of allowances allocated to the APCR without change to the offsets compliance limit. As explained in the first cap-and-trade regulation, these allowances were reserved when the fraction of offsets useable for compliance was increased from 4% to 8% of a covered entity's total compliance obligations. The current proposal includes no changes to the use of offsets for compliance, so ARB needs to explain why the reasoning that led to the creation of the APCR in the first place is no longer valid. We believe ARB should restore the 4% annual contribution to the APCR, both as an insurance policy against the potential for problems with offsets' environmental integrity and to overall maintain policy stringency.

Finally, we note that ARB's proposal reflects a major shift on offsets policy that needs further discussion and the possibility for comment on the part of interested parties.⁴⁴⁸ (WARA)

Comment:

Transition Assistance and APCR

Staff proposes to eliminate transition assistance and allowances allotted for the Allowance Price Containment Reserve (APCR) beginning in 2021 and proposes complete elimination by 2030. ARB will freely allocate allowances to industrial sectors based on leakage risk.

Recommendation: Transition assistance and APCR should continue to be provided beyond 2021 and 2030. This would provide staff flexibility that would allow the cap-and-trade program to respond to market issues. As the cap declines, the cost of allowances will increase. While the APCR has not been utilized at this time, it is highly likely the

⁴⁴⁵ See California Air Resource Board, Proposed Regulation to Implement the California Cap-and-Trade Program, Vol. III, Appendix G: Allowance Price Containment Reserve Analysis (Oct. 28, 2010) at G-11 to G12, available at <https://www.arb.ca.gov/regact/2010/capandtrade10/capv3appg.pdf>.

⁴⁴⁶ ISOR at 13.

⁴⁴⁷ Id.

⁴⁴⁸ We note that ARB has also proposed contemplating the post-2020 use of sectoral forestry crediting programs in Acre, Brazil. However, ARB proposes that the form these programs would take is as a link to an external trading system, despite the fact that this type of program would normally be considered an offset program in substantive policy terms. Id. at 21-22. Whether such external links would count towards the 8% offsets limit is a critical policy question that deserves explicit deliberation and opportunity for notice and comment.

price will escalate as the overall cap declines. By keeping APCR, ARB would have the option to provide relief in tighter markets. ARB could exercise this option as it sees fit and it would not be a mandatory program.

The state's policy focus should be to reduce emissions while keeping businesses competitive in a global market. Currently, less than one percent of global emissions come from California. California should remember its goal is not ultimately just to reduce emissions but also to create a model for others, and these changes could assist in this effort by minimizing the cost of the program.

Table 8-2: Number of California GHG Allowances Allocated to the APCR for Budget Years 2021-2031 (page 162)

In this table the annual number of allowances allocated to the APCR are shown to decrease each year from 2021 to 2030, with no allowances allocated to the APCR from the 2031 budget year and beyond. We disagree with the proposal to discontinue the price containment allowances post-2030 because that is when we anticipate the cost of allowances will likely skyrocket and covered facilities will need the additional protection. (AGCOUNCIL)

Response: As the commenter notes, ARB staff did not propose modifying the offsets usage limit, so that portion of the comment is outside the scope of the rulemaking. As explained in the Initial Statement of Reasons, staff used a linear rate of decline to calculate the proposed framework for annual allowance budgets and the lower cumulative emissions estimated for the 2020 cap to the 2030 cap, and maintains the belief that the total allowances allocated to the Reserve post-2020, along with the other cost-containment features of the program, including limited usage of offsets, will be sufficient to meet the cost containment needs of the Program through 2031. For staff's response to the transition assistance issue, see response to 45-day comment B-6.1.

Leaving Unused APCR Allowances in APCR

H-4.10. Comment:

SMUD supports the components in the Proposed Amendments that add to and alter the APCR structure by:...

- leaving any unused allowances in the current APCR in place after 2020.

(SMUD)

Response: Thank you for the support.

Rationale for APCR Budget and Prices

H-4.11. Comment:

WPTF supports CARB proposed consolidation of the existing three APCR tiers into a single tier. We also support limitation of the potential price spread between the allowance clearing price and the APCR price.

However, we are concerned that CARB has not provided any analysis to support \$60 as the appropriate spread between auction and reserve allowance prices. Staff have also not provided an analytic basis for the proposal to place approximately 2% of the total 2021-2031 allowance budget into the APCR. WPTF requests that CARB provide its analysis and rationale for proposing these numbers. Additionally, we would like to better understand the implications, under a range of possible future market conditions, of the proposal that any allowances offered at auction that remain unsold 24 months be moved to the APCR. (WPTF)

Response: Staff have modified the proposal so that the gap between the Auction Reserve Price and the single top Reserve tier price is equal to the gap that would have occurred under the existing regulation for the third tier. The approach reduces the divergence between the top tier and the Auction Reserve Price that would have occurred under the original regulation.

Staff believes the number of allowances allocated to the Reserve after 2020, together with the carryover of the current Reserve and the existing provisions to replenish the Reserve with future vintage allowances is sufficient for the Reserve to meet any reasonable forecasted demand. For the portion of the comment referring to the amendments that would move allowances that remain unsold for 24 months to the Reserve, see response to 45-day comment H-3.2. In addition, the Legislature has provided direction regarding the Reserve after 2020 in recently enacted AB 398. ARB staff will initiate a new rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Reforming APCR

H-4.12. Comment:

MARKET REFORMS ARE NECESSARY

In order to ensure market stability and cost-containment, there need to be reforms made to the Allowance Price Containment Reserve (APCR). Post-2020 emissions reductions will constrain the market as the cap declines at a more rapid rate. Price containment in the APCR is necessary if the reserve is to be a true cost-containment mechanism. We recommend that there be further consultation with market experts in order to make necessary reforms to ensure the stability of the market and maximize cost-containment. (CALCHAMBERCOMMERCE)

Response: Staff continually monitors the market to assess changes in market prices. Staff will continue to consult with market experts as it has done throughout the program's existence. Staff also believes the proposed system, along with the provisions for replenishing the Reserve with future vintage allowances, will enable ARB to adequately assess market conditions and functioning of cost-containment provisions in a timely manner.

H-5. Post-2020 GHG Emissions Budget

Support for Proposed Linear Cap Decline to 2030

H-5.1. Multiple Comments:

The proposed decline in the cap to reach the 2030 target is reasonable

The Conservancy supports CARB staff's proposed decline in the GHG emissions cap between 2021 and 2031 at a linear rate of approximately 3.5% annually. A steady decline in the cap at this rate will provide capped entities with some stability and consistency to plan for long-term investments to reduce emissions. (CONSERVANCY)

Comment:

We also support the proposed decline in the cap. We think the 3.5 percent annual reduction is reasonable. (CONSERVANCY2)

Comment:

Additionally, we support staff's proposal for a linear cap decline from 2020 onward rather than a steep adjustment. (PG&E3)

Comment:

Support the Proposed Straight-line Emission Budgets from Original 2020 Cap to 2030- SoCalGas supports ARB's post-2020 emission cap levels as presented in the Proposed Amendments to the Cap-and-Trade Regulations; a linear decline between the established 2020 cap and the calculated 2030 cap level. (SOCALGAS)

Comment:

Cap Setting. SCPPA supports a well-designed, economy-wide market based system that includes necessary cost containment protections. SCPPA also appreciates ARB staff's proposal to apply an approximately 3% annual linear reduction path for emissions caps between 2020 and 2030, rather than a —step down or programmatic —shave that could more significantly impact the electricity sector versus other sectors. (SCPPA)

Response: Thank you for the support. Staff agrees that the framework for linearly decreasing annual caps from 2020 to 2030 sets a reasonable path to achieving California's GHG reduction goals. The caps decline each year on a trajectory to achieve the 2030 target. This known reduction in allowances and

escalating floor price provide a clear picture for covered entities to plan compliance activities and other business investments.

Opposition to Proposed Linear Cap Decline to 2030

H-5.2. Comment:

NAIMA OPPOSES CARB'S PROPOSAL TO REDUCE THE PROGRAM CAP ON GHG EMISSIONS 3.5 PERCENT A YEAR FROM 2021 TO 2030 – THIS RATCHETING DOWN IMPOSES BURDENS ON MANUFACTURERS

CARB has a statutory obligation to prevent leakage. The proposed ratcheting down will ultimately result in loss of business in California. NAIMA urges CARB to limit or abandon the ratcheting down of the Cap-and-Trade Program cap. (NAIMA)

Response: Staff considers the framework for linearly decreasing annual caps from 2020 to 2030 as a reasonable path to achieving California's GHG reduction goals. A declining cap is necessary to reduce the amount of emissions allowed within the Cap-and-Trade Program, which is the primary purpose of the program. The caps decline each year on a trajectory to achieve the 2030 target. This known reduction in allowances and escalating floor price provide a clear picture for covered entities to plan compliance activities and other business investments. As such, staff declines to make the change requested by the commenter.

Support for Proposed Linear Cap Decline to 2050

H-5.3. Multiple Comments:

Southern California Edison also supports ARB's post-2030 annual cap-setting methodology. However, a review process should be put into place to monitor program costs and feasibility going forward. This is particularly appropriate considering the large degree of uncertainty that exists when considering California's multi-decade effort to reduce greenhouse gases. (SOCALEDISON)

Comment:

Support the Continuation of Linear Emissions Cap from 2031-2050- The continuation of a linear cap on emissions to 2050 provides a long-term signal to stakeholders. Staff also proposes an equation that would be used to calculate the 2031-2050 annual allowance budgets. These proactive actions support long-term planning and generally contribute to the stability of the emissions market. (SOCALGAS)

Comment:

IETA also applauds ARB for proposing to set initial allowance budgets through 2050. This signals a long-term trajectory of California's market program and helps to inform long-term investment decisions. (IETA)

Comment:

We also support a straightforward 2050 formula methodology to calculate annual allowance budgets. SCPPA agrees with ARB staff's proposal to allow any allowances of vintage 2020 or earlier to be used for compliance in a post-2020 program as a signal that this program will be available for the long-term; however, we do have concerns with staff's proposal to lock-in annual allowance budgets for 2031 through 2050. SCPPA believes it is extremely important that such intent also be associated with rigorous long-term market monitoring mechanisms; ongoing expert evaluation of economic feasibility and technological/commercial viability; and, meaningful cost containment features that offer certainty and protect California ratepayers for the long-term. SCPPA is concerned that not taking steps now to ensure these long-term market protections may negatively impact the program over coming decades – particularly given commensurate efforts underway to “link” other international parties to the program that do not have a federal Clean Power Plan obligation, discussions to regionalize California's electric grid (with other states that do not have Cap-and-Trade and/or Renewables Portfolio Standard mandate(s) either as aggressive as California's or at all), and future EPA Clean Power Plan compliance efforts on a California-only or linked basis. (SCPPA)

Response: Staff appreciate the support for the decision to continue banking of 2020 and earlier compliance instruments beyond 2020. Staff believes this is important for cost containment and to allow registered entities to plan future acquisitions.

Staff agrees that the framework for linearly decreasing annual caps from 2030 to 2050 sets a reasonable path to achieving California's GHG reduction goals. These caps are set to signal the long-term trajectory of the Program to inform future investment decisions by covered entities. As stated in the August 2016 Staff Report, staff recognizes that the framework for 2031-2050 caps may need to be refined in the future, and staff will continue to evaluate the appropriateness of these caps as part of future Scoping Plan updates and post-2020 discussions about how best to meet the long-term 2050 target.

H-5.4. Comment:

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 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. (PG&E)

Response: Staff appreciates the support for the proposed post-2020 Cap-and-Trade Program and is committed to maintaining cost-containment measures and regularly evaluating the Program through, among other discussions, the Scoping Plan update process that occurs every five years.

Reducing 2021 Cap

H-5.5. Multiple Comments:

Cap Setting. To ensure the program provides a strong incentive in support of emissions reductions and investments, we recommend ARB populate the APCR with allowances taken from annual cap budgets that start at or below projected business-as-usual emissions in 2021 –not a linear decline from the 2020 cap, as proposed...

Staff has proposed to set annual cap budgets from 2021-2030 that represent a linear decline from the existing cap in 2020 (334.2 MMTCO₂e) to a level in 2030 that represents the same proportion of statewide emissions that are projected to be covered under the cap in 2020 (77.5%, or 200.5 MMT based on the 2030 statewide target of 258.6 MMT). To address concerns related to over-allocation and cost containment, however, staff proposes to place into the Allowance Price Containment Reserve (APCR) those allowances that represent the delta between a linear decline from the existing 2020 cap and a linear decline that starts at the significantly lower projected emissions levels for capped sectors in 2020 (322.6 MMT) from ARB's ongoing Scoping Plan economic modeling.

This represents an attempt at a middle ground between the two options staff workshopped in March, which would have either simply continued a linear decline (Option 1) or had the cap “step down” in 2021 to adjust for the significant headroom between the current cap budget in 2020 and projected emissions levels (Option 2). While we appreciate staff's recognition of the concerns regarding over-allocation, the current proposal does not go far enough to correct them.

As ARB has recognized in other contexts, a lax cap will undermine the efficacy of the program in driving the scale and timeliness of investments needed to put California on a path toward deep decarbonization. In comments to EPA on the Clean Power Plan model rule, for example, ARB highlighted the importance of taking corrective action in the event a mass-based cap significantly exceeds covered emissions.⁴⁴⁹ To prevent that scenario, ARB recommends that EPA include a pre-established mechanism in the rule to revisit and adjust mass-based targets for states as needed based on actual

⁴⁴⁹ http://www.arb.ca.gov/cc/powerplants/arbcommentsfedplan-01_21_2016.pdf.

emissions in the years leading up to the start of the program in 2022, recognizing that “a lax cap would result in minimal carbon reductions beyond the status quo.”⁴⁵⁰

Bringing the cap in 2021 in line with projected emissions represents that same corrective action in California. A step down should accordingly serve as the floor of ambition for the start of the post-2020 program. The pre-2020 cap began at forecast business-as-usual emissions levels for the (original) start of the program in 2012, with the allowances that populate the APCR carved out from within – not above – those budgets. The post-2020 program will, as proposed, start from an even more lax position.

We also find no basis for directing allowances equal to the “adjustment” from a linear trajectory into the APCR. Even behind a steep and escalating paywall, access to allowances in the APCR would authorize roughly 175 MMT of additional emissions – or more than half of the entire 2020 budget. The proposal seems to presume that covered entities are owed an enhanced safety valve for merely bringing the cap in line with actual emissions. They do not.

Achieving SB 32’s requirement of reducing statewide emissions at least 40 percent below 1990 levels by 2030 will undoubtedly require significant reductions beyond any business-as-usual forecast. But absent correction, the strength of the market signal that the cap-and-trade program provides to assist in achieving that aggressive target will be muted due to the significant oversupply that will carry over into the post-2020 program.⁴⁵¹ And since the climate impact of greenhouse gases in the atmosphere is cumulative over time, the trajectory of reductions in California is significant – not merely the end point.

The participating states in the Regional Greenhouse Gas Initiative (RGGI), facing a similar situation in the wake of the 2008 recession that dramatically reduced emissions relative to business-as-usual forecasts, reduced their program cap nearly in half to bring it in line with actual emissions.⁴⁵² ARB should likewise tighten California’s cap in advance of the post-2020 program to reflect updated emissions trends and forecasts. (NRDC)

Comment:

Support a 2021 cap based on expected actual emissions in 2020:

Since the impact of greenhouse gas pollution in the atmosphere is cumulative over time, the trajectory of reductions in California is environmentally significant. An earlier

⁴⁵⁰ *Id.* (at 19-20).

⁴⁵¹ See, e.g., CaliforniaCarbon.info, “2020 baseline emissions forecast for California cap and trade,” (finding the allowance market will remain oversupplied by a cumulative total of 120-140 million tons by 2020); California Market Compliance Association’s comments on proposed 45-day amendments at <https://www.arb.ca.gov/lists/com-attach/10-capandtrade16-UTJdNgdlU2FQCVU2.pdf> (estimating oversupply may reach as high as 300 million tons).

⁴⁵² See http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.

reduction on greenhouse gasses has a greater benefit to the atmosphere than an equivalent reduction in a later year. In informal workshop comments, EDF supported ARB setting the 2021 allowance budget based on the most up-to-date expectation of emissions in 2020 (which are broadly anticipated to be below the level of the 2020 allowance budget), rather than based on a straight line reduction from 2020 to 2030. We continue to support this approach.

ARB is proposing an approach where an amount of allowances equivalent to the difference between the 2021-2030 allowance budgets implied by using the most up-to-date expectation of 2021 emissions versus the straight-line (i.e., between the 2020 allowance and 2030 allowance budgets) trajectory would be placed in the Allowance Price Containment Reserve (APCR). If allowances prices remain below the APCR, this would have a similar practical effect to setting the post-2020 budget based on the most up-to-date expectation of 2021 emissions. However, the long-term difference in the aggregate level of the cap could weaken the price signal to the economy. The fact that actual 2020 emissions are expected to be below the 2020 allowance budget shows that businesses can make the sorts of deeper emissions reductions that will be necessary for California to achieve its post-2020 reduction targets. Market participants do not have an established expectations about post-2020 budgets that have not yet been set. Therefore, stakeholders do not have a legitimate claim to allowances that represent a budget set at the straight-line reduction trajectory.

Maintaining consistency with previous cap-setting practices and stated policy positions would also suggest that ARB should set the 2021-2030 allowance budgets based on the most up-to-date expectation of 2021 emissions. ARB set the 2013-2020 allowance budgets based on expected emissions and then set aside APCR allowances from below those budgets. In reference to EPA rulemaking, ARB has noted how important cap adjustments would be if a mass based cap was significantly above actual emission levels, due to unforeseen factors affecting emissions. In this context, a cap adjustment is also appropriate given that factors related to imported electricity may have made it easier than anticipated for importers to bring (or appear to bring) clean energy into California. Given these dynamics we believe ARB should err on the side of being conservative, setting a tighter rather than a looser cap.

EDF believes that the 2021 cap should be set based on the most up-to-date expectation of 2021 emissions and that APCR allowances should be set aside from under that cap level, perhaps with some relationship to the level of the offsets limit. (EDF)

Comment:

We think it's also critical that California sets the strongest cap that's feasible. And for that reason, we continue to support a cap for 2021 that would be set based on the expected actual emissions in 2020, rather than the current proposal of the straight line down from 2020 to 2030. And we think that's feasible for businesses to achieve. (EDF2)

Comment:

Extending cap levels beyond 2020 plays a critical role in contributing to the continuation of California's market program. IETA supports the pairing of the "straight-line" cap reduction path from 2020 to 2030 with the allocation of surplus allowances, the delta between the standard and adjusted caps, to the APCR. The alignment of the adjusted cap with forecasted 2020 emissions should incent market participation and liquidity by producing a balanced market. (IETA)

Comment:

Maintaining the established 2020 cap level is consistent with the stated goals of AB 32, and the 2008 California Climate Change Seeping Plan: reducing greenhouse gas emissions to 1990 levels by 2020. We agree with the decision to reject the 2020 to 2021 "step-down" that was previously considered, but ultimately not included in the Proposed Amendments. We believe this is the correct decision because it would have resulted in a reduction in allowances that could have led to unintended and unknown ratepayer impacts. (SOCALGAS)

Comment:

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. (PG&E)

Response: In setting the 2021 cap, staff balanced the needs of providing the necessary environmental benefits and containing Program costs. Staff has heard concerns from stakeholders about post-2020 Program costs escalating as the annual caps decrease and about the Program providing an insufficient price signal to provide environmental benefits owing to a potential over-supply of allowances.

As described in some of the comments, staff evaluated two options for setting the framework for linearly declining caps from 2021 through 2030: (1) set the caps equal to a straight line between the current 2020 cap and the 2030 cap, or (2) step down the 2021 cap to a lower level based on currently projected emissions, and then set the caps equal to a straight line between that 2021 cap and the 2030 cap. The difference in the 2021 cap under these two approaches is 10.5 million MTCO_{2e}. Over the decade, the cumulative difference between these approaches is 52.4 million MTCO_{2e}, and this difference can be seen as a triangular-shaped wedge when both sets of 2021-2030 annual caps are plotted graphically.⁴⁵³

⁴⁵³ Cap-and-Trade Regulation 2016 Staff Report: Initial Statement of Reasons, p. 13: <https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

In setting the framework for 2021 to 2030 annual allowance budgets, staff has set annual caps at a straight line path between the 2020 and 2030 caps, and the 52.4 million “wedge” allowances are allocated to the Allowance Price Containment Reserve (APCR) from within these annual budgets. This approach puts the number of vintage 2021 allowances available at auction in line with current 2021 emissions projections while providing some additional cost-containment in the form of allowances allocated to the APCR.

Allowances that were originally allocated to the APCR from 2013-2020 budgets were also drawn from within the established caps, which were set in accordance with ARB’s emissions projections. At that time, this method of establishing the allowance budgets and allocating to the APCR was adopted in the context of a larger cost-containment discussion that resulted in increasing the maximum offset credit usage limit from 4 percent to 8 percent of the total compliance obligation. No adjustment was made to the 8 percent offset usage limit in this rulemaking. The proposed framework of setting the post-2020 caps in line with the current 2020 cap, with no step-down to the projected emissions level, combined with allocating the 52.4 million “wedge” allowances balances concerns about budget over-allocation and cost-containment in a way that is similar to the balance achieved while establishing the original 2013 to 2020 annual caps.

One comment suggests the presence of the Reserve provides the covered entities with a safety valve as allowances created after 2020 are added to the Reserve. This critique implies the emissions covered by the Reserve would be in excess of the annual cap. This is not the case as the allowances are issued under a cap that declines from 2020 onwards. Even with the proposed additions, the Reserve is still finite and all the allowances in the Reserve would be available at what is now the highest price tier. See response to 45-day comment H-4.1 regarding the sufficiency of the existing APCR and proposed post-2020 APCR in helping meet cost-containment goals, as well as the requirements of AB 398 with respect to establishing two price containment points at levels below the price ceiling. Based on this, ARB staff declines to make the changes proposed by the commenters to move away from the linear cap decline toward a step-down approach. Staff will continue to monitor whether any further modifications are needed, and such modifications would be conducted through the public rulemaking process. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Setting the 2030 Cap

H-5.6. Multiple Comments:

Reduce the annual allowance budget to reflect the strong likelihood that in practice, feasible emission reductions from uncapped sectors will be less than from capped

sectors in proportional terms—or provide a reasoned justification for the current assumption that both sectors can achieve equally proportional reductions...

Consider lowering the Annual Allowance Budget to better account for the technical and regulatory challenges of reducing emissions in uncapped sectors.

The draft rule sets annual allowance budgets from 2021 through 2031 by assuming that the proportion of capped to uncapped emissions remains constant from 2020 to 2030.⁴⁵⁴ This critical assumption is unjustified in the ISOR and is most likely false. If ARB's assumption of proportional reductions in capped and uncapped sectors turns out to be too difficult to achieve in practice, ARB will most likely fail to achieve the goals recently articulated in SB 32.⁴⁵⁵

We believe the allowance budget has been set too high. On the assumption that uncapped sectors reduce their emissions in line with the reductions in the proposed cap-and-trade extension, ARB sets the capped sectors' budget at 200.5 million metric tonnes carbon dioxide equivalent (mmtCO₂e) in 2030. Because we are skeptical that uncapped sectors can achieve a comparable share of emission reductions, we suggest the capped sectors' budget should be lowered to a level of approximately 160 mmtCO₂e in order to reflect more conservative assumptions about feasible reductions from uncapped sectors. Again, absent such a modification, the proposed regulation creates a significant probability that ARB will fail to comply with the statewide greenhouse gas emissions limit recently enacted in SB 32.

Fundamentally, the assumption that capped sectors will maintain their current proportion of total statewide emissions through 2030 is not credible without substantially more justification than the ISOR provides.

In order for capped and uncapped sectors' emissions to maintain their current proportion, ARB has assumed that unspecified regulatory measures will lower emissions in the uncapped sectors by 40% from 2020 to 2030. But these sectors are uncapped precisely because their emissions are hard to measure, control, and regulate—and in some instances, for all of these reasons. For example, what is ARB's plan for lowering emissions by 40% from the agricultural sector, including the production of methane from ruminant animals and the emissions of nitrous oxide from soils? What about biomass burning from forestry?

Merely asking these questions illustrates why the assumption of constant proportionality most likely isn't sound. At a minimum, the state should consider how the proportion of emissions from capped sectors has changed from 2004 peak statewide emissions to the present: over this period, agricultural and forestry emissions have increased 7%, up

⁴⁵⁴ ISOR at 12-13.

⁴⁵⁵ SB 32 established a 2030 statewide greenhouse gas emissions limit of 40% below 1990 levels. Cal. Health & Safety Code § 38566. In absolute terms, this target is equivalent to 258.6 mmtCO₂e in 2030. ISOR at 12.

from 33.8 to 36.1 mmtCO₂e.⁴⁵⁶ By contrast, statewide emissions as a whole have decreased by almost 10%, down from 487.6 to 441.5 mmtCO₂e.⁴⁵⁷

Thus, if intuition and recent history are any guide, ARB should make the opposite assumption: that uncapped sectors will have a harder time cutting emissions relative to capped sectors. This is especially true if easy reductions—the so-called low hanging fruit—have already been exploited. In that case, it would follow that uncovered sources will make up a larger fraction of statewide emissions in 2030 than at present or in 2020. In turn, capped sectors will have to reduce their emissions by a larger fraction than uncapped sectors in order to achieve SB 32's 2030 target. Given that the most cost-effective reductions are likely available within the electricity sector—a capped sector—our recommended approach may also be more cost-effective than ARB's constant proportionality assumption.

A more conservative approach to estimating capped sectors' contribution to the 2030 target would assume that emissions from uncapped sectors will remain in 2030 at their expected 2020 levels, which ARB projects will be ~100 mmtCO₂e.⁴⁵⁸ This is a stark difference from the ~60 mmtCO₂e target ARB implicitly assigns to uncapped sectors in 2030.⁴⁵⁹ The difference (~40 mmtCO₂e) represents almost 16% of the state's 2030 target—a reduction in emissions that ARB assumes will be achieved in the uncapped sectors, without analysis or specificity.

Another way to interrogate this assumption is by examining required annual rates of emission reductions. Under ARB's proposal, capped sectors will reduce emissions at a constant rate from 2021 to 2030 of approximately 13.3 mmtCO₂e per year.⁴⁶⁰ In contrast, statewide emissions from all sectors must fall by 17.2 mmtCO₂e per year, leaving ~4 mmtCO₂e per year to be achieved by as-of-yet unspecified measures in uncapped sectors.⁴⁶¹ For comparison, the required rate of statewide emission reductions from the most recent data in 2014 to the 2020 target is only ~1.8 mmtCO₂e

⁴⁵⁶ ARB, California Greenhouse Gas Emission Inventory – 2016 Edition (June 2016), available at <https://www.arb.ca.gov/cc/inventory/data/data.htm>.

⁴⁵⁷ Id.

⁴⁵⁸ ISOR at 12. The 2020 target is 431 mmtCO₂e; ARB projects capped sectors will achieve 334.2 mmtCO₂e in 2020, which implies that uncapped sectors could emit as much as 96.8 mmtCO₂e while still complying with the 2020 statewide target. Id. However, ARB also projects that capped sectors will emit less than the 334.2 mmtCO₂e limit in current regulations, and will instead emit only 322.6 mmtCO₂e. Id. This implies that uncapped sectors could emit up to 108.4 mmtCO₂e. Thus, based on ARB's projections for 2020, the potential range of maximum 2020 emissions from uncapped sectors is 96.8 to 108.4 mmtCO₂e.

⁴⁵⁹ ARB proposes that the 2030 budget for capped sectors should be 200.5 mmtCO₂e, maintaining a 77.5% share of the total state budget for 2030 (258.6 mmtCO₂e). Id. With this proposed budget for capped sectors, uncapped sectors are implicitly assumed to emit no more than 58.1 mmtCO₂e.

⁴⁶⁰ Id.

⁴⁶¹ Taking the 2030 target as 258.6 mmtCO₂e and the 2020 target as 431 mmtCO₂e requires an average annual reduction of 17.24 mmtCO₂e per year over ten years. The difference between this rate and ARB's proposed rate of reductions for capped sectors of 13.3 mmtCO₂e per year is 3.94 mmtCO₂e per year.

per year.⁴⁶² Thus, the share of 2030 ambition assigned to uncapped sectors requires reductions more than twice what is currently required for statewide progress toward the 2020 target.

Alternatively, if uncapped sectors maintain their emissions at 2020 levels in 2030, meeting the 2030 target requires that the budget for capped sectors in 2030 should be ~160 mmtCO₂e, rather than ARB's proposed 200.5 mmtCO₂e. Our suggestion would require emission reductions from capped sectors over the 2021-2030 period of approximately 52%, rather than by 40% as ARB proposes.⁴⁶³

If ARB believes (for reasons unspecified in the ISOR) that the 2030 allowance budget for capped sectors should be set at 200.5 mmtCO₂e—or some other intermediate value in between 160 and 200.5 mmtCO₂e—then Staff should provide a reasoned justification including a quantitative estimate for reductions to be achieved in uncapped sectors. In simply asserting without analysis that uncapped emissions will fall in proportion to capped sector emissions, the ISOR does not comport with recent experience, let alone the technical, economic, and political challenges of reducing emissions in the largest uncapped sectors. (WARA)

Comment:

The mix of covered entities and the amount of emissions will change over time and the new 2030 goal is very stringent, the rationale for the cap number should be more robust than simply that ARB applied the same percentage as in 2010's rulemaking. It is not clear why it is necessary to make the cap for cap-and-trade more stringent than the overall state goal of 256.6. (CCPC)

Response: It is appropriate to set the 2030 emissions cap for the Cap-and-Trade Program at a level below the statewide goal of 258.6 MTCO₂e because the Cap-and-Trade Program covers a subset of the statewide GHG emissions included in AB 32 and SB 32 targets. Not all GHG emissions in California are covered by the Program, so the 2030 Program cap must be lower than the statewide target to accommodate emissions from uncapped sectors.

Retaining the same percentage of the State's GHG emissions for setting the 2030 cap reflects staff's expectation that all emissions sources, whether they are within the Program cap or not, will pull fair weight in making progress toward the 2030 statewide target. Setting the 2030 emissions cap at 200.5 MMTCO₂e assumes that emissions that are outside of the Program cap will be reduced at the same rate as those within the Program cap through a suite of targeted measures.

⁴⁶² California Greenhouse Gas Inventory, supra note 4.

⁴⁶³ The 2020 budget for capped sectors is 334.2 mmtCO₂e. ISOR at 12. A 2030 budget for capped sectors of 160 mmtCO₂e would require a 52.1% reduction from 2020 levels; ARB's proposed budget for capped sectors of 200 mmtCO₂e would require a 40.0% reduction from 2020 levels.

Emissions outside the cap primarily come from the agriculture and waste sectors and from high-GWP gases. The legislature and ARB staff recognize the importance of emissions reductions in these sectors for achieving statewide emissions goals, and recent legislation and regulations have been adopted to directly address these sources in the coming years. Pursuant to SB 605 and SB 1383, ARB has adopted a Short-Lived Climate Pollutant (SLCP) Reduction Strategy,⁴⁶⁴ which charts the State's plan to reduce statewide emissions of methane and hydrofluorocarbons to 40 percent below 2013 levels by 2030 and reduce statewide emissions of black carbon to half of 2013 levels by 2030. Specific measures in the strategy for reducing methane emissions include adopting and implementing emissions standards for crude oil and natural gas facilities and implementing SB 1371 to reduce natural gas pipeline emissions. The SLCP Reduction Strategy also includes measures to restrict the use of high-GWP gases for refrigeration and other applications. SB 1383 also included a number of directives for addressing dairy and livestock sector methane emissions and landfill methane emissions via diversion of organic material from the waste stream. ARB recently adopted a regulation to reduce emissions from crude oil and natural gas production facilities. Other measures focused on these sectors are detailed in ARB's proposed 2017 Scoping Plan Update. If these measures are not sufficient to drive emissions from these uncapped sectors to the levels assumed by the current 2030 cap-setting approach, ARB will continue to pursue reductions from these sectors through regulations, incentives, and other means to ensure that the 2030 statewide goals are met. See also response to 45-day comment H-5.5.

Reducing 2020 and 2050 Caps

H-5.7. Comment:

Increase 2020 reduction target to 50%, aiming up to 100% reduction by 2050. (EJAC)

Response: This comment is specific to proposing changes to the RPS, which is outside the scope of this Cap-and-Trade rulemaking.

H-6. Scheduling

Separating Forward and Current Auctions

H-6.1. Comment:

CARB should conduct Current Vintage Auctions and Forward Vintage Auctions on separate days/times, to allow for participants to receive notification of purchases in the Current Auction prior to submitting bids in the Forward Auction.

⁴⁶⁴ ARB (2017). Short-Lived Climate Pollutant Reduction Strategy. Available here: <https://www.arb.ca.gov/cc/shortlived/shortlived.htm>

- a) CARB should recognize that the outcome of the current vintage auction and individual participants' success or failure in such auction clearly affect the decision by market participants to bid in the Forward Auction. By holding both auctions simultaneously CARB is potentially negatively affecting bids in both the Current and Future vintage auctions.
- b) CARB could easily separate the auctions with little or no incremental costs by holding the Forward vintage auction the day after the results of the Current vintage auction are announced. (CMCA)

Response: The commenter requests modifications to the regulation that would separate current and future vintage auctions. ARB staff did not include any changes as part of this rulemaking that would make such a substantial change. As such, the comments are outside the scope of the proposed amendments.

Cancelled Auctions

H-6.2. Comment:

This section [95911(h)] 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. (PG&E)

Response: Staff agrees with the commenters' suggestion of ensuring additional detail so stakeholders understand the steps outlined in the regulation text. Staff is committed to ensuring that additional information, in particular if it were to relate to a delay, rescheduling, or other issue with an actual auction, would be shared in a manner to ensure equitable, timely access to such information for all market participants.

I. DOMESTIC AND INTERNATIONAL LINKAGE

I-1. Linkage in General

Support for Linkage

I-1.1. Multiple Comments:

TNC supports continued program linkages with other jurisdictions

The Conservancy strongly supports continued and expanded linkages of the cap and trade program with other jurisdictions, such as Quebec and Ontario. As acknowledged in the Initial Statement of Reasons (ISOR) on page 9, "climate change is a global problem that California cannot solve on its own; regional and global partners are needed." The ability to link with other jurisdictional programs provides the opportunity to leverage additional GHG reductions at reduced costs, which in turn, encourages other

jurisdictions to develop programs to reduce emissions – as it serves to counter arguments that GHG reductions come at the expense of economic development. California has successfully linked with the province of Quebec and it should continue to link with other governmental jurisdictions like Ontario and others. (CONSERVANCY)

Comment:

...and pursue reasonable linkage opportunities with other jurisdictions. All of these proposals will help control the costs borne by utility customers while enabling Cap-and-Trade to deliver the emission reductions necessary to achieve the state's longterm climate goals. When viewed as a key element, JUG members believe cost containment can increase the effectiveness of California's Cap-and-Trade program and demonstrate leadership to jurisdictions considering their own climate policies. (JOINTUTILITIES)

Comment:

Linkages. SCPPA generally supports programmatic "linkages" as a means to potentially reduce costs to California ratepayers. We are concerned, however, with any proposal that could seemingly establish a simplified procedural manner to establish linkages – particularly one-way linkages (e.g., with the State of Washington, or if Ontario becomes a net buyer only) – with unequal and less stringent qualifications for operational integration (e.g., California/Quebec two-way linkage) and without vigorous vetting by agency leaders. SCPPA is concerned there may be undue burdens that California ratepayers may experience due to leakage risks and added in-state economic development constraints and/or competitive disadvantages. We believe it is important that linkage protocols be inclusive of pre-established criteria – with input included through a meaningful public stakeholder process – to ensure inclusion of meaningful cost containment features. This is particularly problematic given the current implementation of California policies directly affecting California's electric utility sector associated with Senate Bill 350, the recently enacted Senate Bill 32 and Assembly 197, and numerous other measures that already place significant climate change-related policy requirements on our Members. Collectively, these existing policies raise the Renewables Portfolio Standard to 50% by 2030, double energy efficiency savings in existing buildings, and set aggressive 2030 emissions reduction targets. SCPPA therefore urges a preference for, and greater support of, rigorous and mutually beneficial two-way linkages with proper safeguards for California ratepayers that are thoroughly vetted through both the ARB staff level, with pre-established Board approval processes. (SCPPA)

Comment:

We also support the staff proposal to continue program linkages with other jurisdictions. As acknowledged many times today, and also on the -- in the staff report, climate change is a global problem that California cannot solve on its own. Regional and global partners are needed. (CONSERVANCY2)

Response: ARB staff appreciates the commenters' support for program linkages with other jurisdictions. With respect to comments regarding concern over one-way linkages, ARB staff notes that the 45-day amendments include proposed provisions that would ensure that any type of linkage – whether it constitutes what the commenter calls “rigorous and mutually beneficial two-way linkages” or more limited retirement-only style linkages – is approached in a public process, with pre-established Board approval processes. ARB staff agrees with the commenter that it is important to conduct a public process to ensure stakeholders have an opportunity to engage on and to seek Board approval of any type of linkage. Therefore, in developing the proposed language on new types of linkage in sections 95944 and 95945 of this rulemaking, staff has included mechanisms to ensure that any linkage that could be contemplated in a future rulemaking would work while preventing the use of California-issued compliance instruments in other systems without public participation and Board approval, and, where necessary, SB 1018 findings.

I-2. Linkage with Ontario

Support for Linkage with Ontario

I-2.1. Multiple Comments:

Support linkage with Ontario

EDF supports ARB moving forward with the process to link Ontario to the California-Quebec market. There are many potential benefits of this linkage but one of the most significant is the work it will do to further California and Quebec's example of how local, bottom-up partnerships and action can help to solve a global threat. The early collaboration that took place in the WCI process continues to bear fruit and allowed participating jurisdictions to consider action at their own pace and adapted to their own local needs. Once Ontario was well situated to take up the issue of cap-and-trade again, they were able to act very quickly and are implementing a cap-and-trade program on a very aggressive timeline because of the intervening work completed by California and Quebec. This avoided delay is a major benefit to the atmosphere which will benefit California and its partners.

Other benefits of the Ontario linkage include market benefits such as a broader market with potentially more cost-effective emissions reductions and greater market liquidity. There are also administrative benefits of cost-sharing within WCI, Inc., for example, related to maintaining the CITTs system and administering auctions. As climate leaders we also hope that California, Quebec, and Ontario will encourage one another to set ambitious caps, caps that not only meet their established targets but that recognize that the trajectory taken to achieve those targets also has significant environmental impacts.

Ontario is well suited for the type of full linkage contemplated in this rule making. Ontario was a WCI participant and is in the process of adopting a cap-and-trade regulation that is well aligned and appears to be harmonized with California and Quebec's programs. Ontario has also set 2020, 2030 and 2050 targets that are more stringent than California's in 2020, slightly less stringent in 2030, and equivalent in 2050. This seems a comparable level of ambition adequate to meet California SB 1018 standards. (EDF)

Comment:

Linkage

We support ARB's ongoing evaluation of linkage with Ontario pursuant to the requirements of Senate Bill 1018. Developed pursuant to the Western Climate Initiative's joint design parameters for a regional cap-and-trade market, Ontario's program is substantially similar and comparably stringent to California's program and will support increased sub-national climate action. (NRDC)

Comment:

Key Theme: Meaningful linkages with other jurisdictions should be pursued. JUG members support the state's plans to link with Ontario and urge the state to pursue additional linkages with domestic and international jurisdictions. The signing of the Paris Accord signals a unique opportunity to seek out trading partners, and JUG members encourage the state to actively pursue this opportunity. (JOINTUTILITIES)

Comment:

SMUD also supports the comments filed by the Joint Utility Group, covering the following key themes:

- Meaningful linkages with other jurisdictions should be pursued...

(SMUD)

Comment:

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...

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. (PG&E)

Comment:

MID supports full, mutual linkages. Linkages that expand the market and increase opportunities for cost reduction, market liquidity and efficient emissions reductions should be pursued. The existing two-way linkage with Quebec and the proposed linkage with Ontario fall under this category and strengthen the Cap-and-Trade program. The Proposed Regulation Order includes amendments to allow two types of one-way linkages with the California Cap-and-Trade program to be available for external GHG programs to take advantage of. (MODESTOID)

Comment:

We're also supporting moving forward with the linkage with Ontario... (EDF2)

Response: ARB staff appreciates the commenters' support of the amendments to link with the Cap-and-Trade Program in Ontario. Many of the benefits of linkage included in the comments are reflected in the rationale included in the Initial Statement of Reasons and the ARB linkage request letter to Governor Brown, the Discussion of SB 1018 Findings for Ontario, and the Governor's Transmittal Response to CARB on Findings under SB 1018. With respect to comments regarding other types of linkages, please see response to 45-day comment I-1.1.

Opposition to Linkage with Ontario

I-2.2. Comment:

Linking With Ontario is Premature and Further Undermines In-State Reductions.

The Proposed Amendments propose to link California's Cap-and-Trade program with the new cap-and-trade program in Ontario, Canada, beginning January 2018. However, the government of Ontario has yet to publish offset protocols, or even to specify those sectors for which it intends to develop offset protocols in the foreseeable future. In June of this year, the government of Ontario indicated that it was considering offset protocols for agriculture, forestry, lands, and resource recovery sectors.⁴⁶⁵

As the Initial Statement of Reasons points out, Senate Bill 1018 (SB 1018; Chapter 39, Statutes of 2012) requires that the Governor of California make specific findings prior to

⁴⁶⁵ "Due to their ability to remove carbon from the atmosphere, Ontario's agriculture, forestry, lands, and resource recovery sectors will be able to supply carbon offsets to the cap and trade market, providing made-in-Ontario compliance options for emitters."

<https://www.ontario.ca/page/climate-change-action-plan#section-11> June 2016 ¹⁰ ISOR at 17.

linking the California Program with other jurisdictions. Among other things, the Governor must find that the linked program has adopted program requirements for greenhouse gas reductions (including, but not limited to, requirements for offsets) that are equivalent to or stricter than those required by AB 32.¹⁰ While this is admittedly not a particularly daunting hurdle, the aforementioned sectors are all highly complex and problematic, and it has proven very difficult for California to develop offset protocols that would effectively provide high-quality offsets. Ontario's protocols would certainly need to be finalized with sufficient time for review not only by the Governor, but by the public and experts, before such credits could be incorporated and accepted into California's Cap-and-Trade program.

Even under the best scenario, in which Ontario is able to develop offset protocols that result in high-quality offsets, linking with Ontario and accepting those offsets credits means that California would be further exacerbating the problems of forgoing in-state direct reductions in exchange for out-of-state offset credits. Again, as indicated by the findings of Cushing, *et al.*, , this is exactly the type of approach that risks prolonging and exacerbating environmental burdens borne by low-income communities and people of color here in California. (CBD)

Response: The commenter objects to the proposed amendments that would link California's Cap-and-Trade Program with the Cap-and-Trade Program in Ontario, Canada, with particular concerns related to any future offset protocols developed in Ontario. As described in the Initial Statement of Reasons, including in the detailed description of Ontario's program (including their offsets design criteria – see Appendix D to the Initial Statement of Reasons), ARB staff believes that linkage with Ontario will provide multiple benefits to the existing linked California-Québec programs. The advantages of linking with other jurisdictions are analogous to the benefits of including multiple sectors under a broad cap-and-trade program. Expanding the number of sources that are able to trade allowances reduces the overall cost of achieving emission reductions and improves the efficiency of the allowance market. In addition, an expanded, linked Program can result in greater emissions reductions than operating the stand-alone California Cap-and-Trade Program because each linked partner jurisdiction also achieves emissions reductions. With respect to Ontario's offsets program, ARB staff indicated in Appendix D to the Initial statement of Reasons that Ontario's offsets program would be consistent with the criteria adopted by both California and Québec. Moreover, ARB staff indicated that linkage would require Governor linkage findings under SB 1018 prior to Board approval of the noticed amendments and that such approval would be requested. ARB staff submitted an approval request to Governor Brown on January 30, 2017, and included a detailed discussion of Ontario's program, including its offsets criteria. The Governor submitted a response letter on March 16, 2017 indicating that the SB 1018 requirements had been satisfied. Moreover, and in the same manner as linkage has been implemented with Québec, ARB staff notes that California has

been coordinating with WCI Partner jurisdictions for close to a decade and will continue to do so to ensure there is consistency throughout a regional market program. Staff will provide the Board with an update prior to any changes in a linked jurisdiction's program, including proposal of future protocols. This will continue to provide an open and public process through which stakeholders can comment on proposed changes. As such, ARB staff declines to make the changes requested by the commenter. With respect to the references to claims made in the Cushing, et al. paper, please see response to 45-day comment K-1.5.

I-3. One-Way Linkages with Other Jurisdictions

Support for One-Way Linkages with Proposed Limitations

I-3.1. Multiple Comments:

The proposed amendments maintain the linkage with the Quebec emission trading system, and anticipate linkage to the Ontario emission trading system. Additionally, CARB staff have proposed two new types of one-way linkages:

- A Retirement-only linkage that would enable compliance units generated by an external program to be used for compliance in California. This linkage would require an SB 1018 finding on stringency. This type of linkage would apply if and when CARB authorizes use of sectoral forestry offsets from programs such as the one in Acre Brazil.
- Additionally, CARB has proposed to allow Retirement-Only agreements that would enable California compliance instruments to be used by entities for compliance in external GHG programs, such as that being developed by the state of Washington. This type of agreement would not require a SB 1018 finding (since compliance instruments will not be coming into California), but would require a formal public process and board approval.

WPTF supports the inclusion of alternative models for linking of California's program to external emission trading programs. As we noted in our comments about the CPP above, we anticipate evolving carbon regulations and trading systems over the next decade. Some of these may be amenable to full linkage with California's program and others will not. Providing for different types of linkages creates more opportunities for harmonizing carbon regulations across jurisdictions. Although the "Retirement-Only Limited Linkage" is proposed as a vehicle for using tropical forestry offsets to be used in the California program, it could also be appropriate for other sectoral offsets.

With respect to the "Retirement-Only Agreement" WPTF also agrees with the proposed prohibition of use of California allowances for compliance by entities in external programs until and unless such a linkage is expressly approved following a public process. Because of the potential of such a linkage to impact the availability and prices

of allowances in California's program, the public process should give explicit consideration to these issues. (WPTF)

Comment:

We also support the new provisions regarding 'one-way' linkage to ensure California retains control over the use of its compliance instruments in external emissions trading programs, such as the recently adopted rule by Washington state, which allows its covered entities to use allowances issued by "an established multisector GHG emission reduction program" like California's up to a certain limit.⁴⁶⁶ (NRDC)

Response: ARB staff appreciates the commenters' support for program linkages with other jurisdictions. ARB staff agrees with the commenters that the 45-day amendments include provisions that would ensure that any type of linkage is approached in a public process, with pre-established Board approval processes. In developing the proposed language on new types of linkage in sections 95944 and 95945 of this rulemaking, staff included mechanisms to ensure that any linkage that could be contemplated in a future rulemaking would work while preventing the use of California-issued compliance instruments in other systems without public participation and Board approval, and where necessary, SB 1018 findings.

Support for One-Way Linkages

I-3.2. Comment:

In particular, IETA applauds the leadership California has shown during the development of Ontario's cap-and-trade program. ARB's close consultation and planning with Ontario officials throughout the process will go a long way to ensuring that the process goes smoothly in 2018, including structural and policy alignment in the post-2020 timeframe. California's commitment to expanding trading partners is also important given the increasing number of North American jurisdictions considering adopting market mechanisms and exploring both full and partial linkage opportunities with Western Climate Initiative (WCI) partners. Most recently, this was evidenced by the Joint Declaration, signed by Québec, Ontario and Mexico, at the 2016 Climate Summit of the Americas. The declaration commits existing and future California partner jurisdictions to "deepen their collaboration...on carbon markets" and to "jointly promote the expansion of carbon market instruments...in North America."

IETA strongly supports the two new linkage options proposed by ARB – neither of which would require the same level of operational integration as the California-Québec (and soon to be Ontario) style program. As IETA has consistently communicated on both sides of the Canadian-US border and beyond, the inherent flexibility of WCI's model

⁴⁶⁶ <http://www.ecy.wa.gov/laws-rules/WAC173442/X1510a.pdf> (WAC 173-442-170).

creates an ideal framework to functionally embrace and enable these proposed types of one-way unit flows. (IETA)

Response: ARB staff appreciates the commenter's support for the proposed amendments.

Opposition to All One-Way Linkages

I-3.3. Multiple Comments:

CMCA supports two-way linkages that provide a market structure where the reciprocal nature of complimentary programs increases depth and liquidity to the market. However, one-way linkages are problematic by design as they tighten the supply/demand balance without any accompanying benefit from a larger more liquid market. CMCA recommends CARB not allow one-way linkages in the regulation without further public consultation. (CMCA)

Comment:

ARB staff proposal

The staff is considering forms of linkages with other trading systems and programs in order to 1) "allow entities in California to retire compliance instruments issued by another GHG ETS to be used to meet their compliance obligation in California," and 2) "allow entities registered in a non-California GHG program to retire California compliance instruments to meet obligations in their own program."

Gaz Métro's comments

Gaz Métro supports linking the California carbon market to markets in other jurisdictions. Gaz Métro also supports the intent to enter into agreements with other programs and systems to allow for the use and withdrawal of compliance instruments issued by other partners.

Such agreements can offer many benefits for all partners, in particular giving covered entities access to a larger pool of compliance instruments, offering them more ways to meet their compliance obligations at the lowest possible cost. Two types of agreements may be considered: unilateral agreements and reciprocal agreements.

Unilateral agreements enabling a member entity to use compliance instruments create a significant risk for other entities within the jurisdiction who would face more competition to acquire compliance instruments. Ultimately, this could result in a shortage of compliance instruments and an increase in compliance costs.

Conversely, if reciprocal agreements were put in place, the price of compliance instruments in each of the partner jurisdictions would likely eventually converge. Of course, it is possible that the price of compliance instruments from California and its WCI partners would increase after the markets are linked; however, it would then be similar to another jurisdiction entering the joint market, such as Ontario. Reciprocal

agreements would prevent a situation in which California entities and those of its WCI partners do not have enough compliance instruments because their compliance instruments are being used too much outside the WCI.

Gaz Métro recommendations

Gaz Métro encourages the opening of the market, provided that other cap systems are similarly open, and that this take the form of reciprocal agreements to avoid creating a sudden shortage in compliance instruments in the WCI and significantly increasing costs. (GAZMETRO)

Response: The commenters have raised concerns with price impacts and object to any one-way linkages without further public consultation. ARB staff notes that the proposed amendments are not proposing any specific linkages at this time (outside of the linkage with Ontario). Rather, the 45-day amendments included proposed provisions to help ensure than any type of linkage, including more one-way linkages, could only be approached through established public process and Board approval in a future rulemaking. If a future linkage were proposed, ARB staff would develop an economic assessment of such linkage pursuant to the requirements of the Administrative Procedure Act, in the same manner as in this current rulemaking. ARB staff agrees with the commenters that it is important to conduct a public process to ensure stakeholders have an opportunity to engage on and to seek Board approval of any type of linkage. Therefore, in developing the language on new types of linkage in sections 95944 and 95945 of this rulemaking, staff has included mechanisms to ensure that any linkage that could be contemplated in a future rulemaking would work while preventing the use of California-issued compliance instruments in other systems without public participation and Board approval. ARB staff believes these provisions are sufficient to address the concerns expressed by the commenters and declines to make further changes to the regulatory language.

Opposition to One-Way Retirement-Only Agreements

I-3.4. Multiple Comments:

The ARB Should Not Allow One Way Linkages With Other Cap-and-Trade Markets.

TID is very concerned that other jurisdictions may be able to draw on the supply of California allowances without creating an additional supply of allowances available to California obligated entities. While Washington State's use of allowances may be a relatively small demand, TID is concerned that as other states pursue GHG reduction policies, there could be a significant new demand for California allowances. In other words, the one-way linkages policy is a "slippery slope" for the integrity of California's program. In general, we believe linkages can be good for the market, but only when the linkages are two-way linkages that create an additional supply of allowances for California obligated entities. (TURLOCKID)

Comment:

Linkage Provisions: SCPPA is leery of allowing outside entities to remove allowances from the California Cap-and-Trade program, especially when the entities are not contributing to the overall allowance pool. These regulatory amendments propose two possible situations where this may occur. The first is the Retirement-Only Linkage, and the second is a full linkage with a jurisdiction that is projected to be a net buyer of allowances from day one (Ontario). The proposed amendments immediately provide for linkage with Ontario, and sets up a process for a future Retirement-Only linkage with Washington State, and others that may wish to join.

These provisions lead to unanswered questions about cost containment, upward allowance price pressures, impacts on the cap and future unknown consequences on the California program. SCPPA has not seen any robust staff analysis on these proposals, or other potential long-term implications. See additional comments under Cost Containment. (SCPPA)

Comment:

The first type, Retirement Only Limited Linkage, would allow California covered entities to purchase allowances from an external program and retire those allowances towards their Cap- and-Trade compliance obligation. Per the Proposed Regulation Order, this type of one-way linkage is only available if the Governor's SB 1018 findings requirements are satisfied and ARB has carried out a public process. (MODESTOID)

The second type of linkage, the Retirement Only Agreement, allows entities that are regulated by external GHG programs to retire California's allowances towards their compliance obligation in their external program. This type of arrangement provides no benefit to the broad Cap-and- Trade market, removes allowances from circulation and is untenable. Furthermore, the criteria for allowing this type of one-way linkage are much less intensive than for a Retirement Only Limited Linkage. Per §95945(a) in the Proposed Regulation Order, the only requirement to establish a Retirement Only Agreement linkage is that, "the Board may approve a Retirement- Only Agreement with an external GHG program." This language does not even require a public process. Any program that links with the Cap-and-Trade program should be at least as stringent in its emissions goals and should offer its compliance instruments in exchange for access to California's allowances. Furthermore, the Proposed Regulation Order mentions a "Retirement-Only Agreement" that would define the nature of the linkage. However, the form and function of the agreement are not fully described. One-way linkages that allow entities in external GHG programs access to California Cap-and-Trade allowances should be prevented. (MODESTOID)

Comment:

Retirement Only Limited Linkage

CLFP is opposed to the adoption of Section 95945 granting the Board the ability to approve Retirement-Only agreements with external GHG programs. It is premature. CARB should not allow external entities to purchase allowances to be used in external compliance situations unless the external program has an operating cap-and-trade program through which California covered entities may obtain external allowances as well. Allowing external entities to purchase California allowances for retirement-only will drive up the cost of compliance for California's covered entities providing increased costs for California populace without significant benefits being obtained in exchange. (FOODPROCESSORS)

Comment:

One-Way Linkages

California's Cap-and-Trade Program should only be linked with other programs if that linkage ensures that there is a sufficient supply of compliance instruments for California compliance entities. Linkages with other emissions-based programs that do not afford California compliance entities access to additional compliance instruments while allowing California compliance instruments to be retired for other than the Cap-and-Trade program should be avoided. M-S-R encourages CARB to seek linkages with other jurisdictions that can be mutually beneficial, but is concerned about one-way linkages that could compromise the ability of California compliance entities to meet their compliance obligations under the declining cap that will be imposed. The Legislature provided clear direction to CARB regarding the criteria that must be met before it would be appropriate to link programs, and each of those provisions should continue to be followed when assessing the viability of potential trading partners with which to link California's Program. M-S-R is also concerned about the ability to reconcile one-way linkages with partners within and outside of the jurisdiction of the EPA's CPP should the CPP become law. The state should pursue arrangements that will allow additional trading among sister states under the CPP program. Especially at the nascent stages of exploring the feasibility of utilizing the Cap-and-Trade program for compliance with the CPP, M-S-R believes that the provisions for linkages already included in section 95943 of the Regulation should be retained. (M-S-R)

Response: The commenters oppose the linkages contemplated by new sections 95944 and 95945 of the regulation. Some comments oppose these provisions based on the commenters' misunderstanding that the provisions would not explicitly require a public process prior to approval of a specific new linkage. ARB staff proposed amendments in the first 15-day amendments to explicitly refer to "public notice and opportunity for public comment in accordance with the Administrative Procedure Act," in order to explicitly acknowledge the public process, and believes this amendment addresses that specific comment. With respect to the commenters' general opposition to these types of linkage, please see response to 45-day comment I-3.3.

Cost Impacts of One-Way Linkages

I-3.5. Multiple Comments:

ARB Should Carefully Evaluate Any Proposal to Allow Export of California Cap-and-Trade Allowances

LADWP supports ARB staff's proposed interpretation that any type of linkage-including a "Retirement-Only Agreement"-requires specific Board approval.⁴⁶⁷ Such one-directional linkage in which entities in another state use California compliance instruments without the opportunity for California covered entities to use compliance instruments issued by the other jurisdiction could result in substantial numbers of Cap-and-Trade Regulation compliance instruments leaving the state. This could increase the costs of California compliance entities without benefit to California or the environment.

LADWP urges ARB to take special care when approving any such one-way linkages with other states that want to utilize California compliance instruments to comply with their state plan under the CPP or a standalone state program (such as the one being developed by Washington). Such linkages can create substantial accounting complexities under the federal CPP. For example, the CPP appears to prohibit the linkage of any two "state measures" plans.⁴⁶⁸

LADWP urges ARB to invest its resources in potential linkages that provide benefits to both California and non-California parties to the linkage agreement-including Retirement-Only Limited Linkages. Such linkages, in contrast to Retirement-Only Agreements, can provide benefits to California ratepayers, including increased compliance instrument liquidity and reduced compliance instrument prices. (LADWP)

Comment:

SCE seeks to ensure that 'one-way linkages' include protections for our customers and all Californians. New forms of linkage have been proposed in this regulatory order, allowing for one-way allowance flows into (or out of) CA. These two new forms of linkage would not require the same level of operational integration as the California-Québec style linkage. The first type would allow entities in California to retire compliance instruments issued by another GHG ETS to be used to meet their compliance obligation in California. The second would allow entities registered in a non-California GHG Program to retire California compliance instruments to meet obligations in their own program. While SCE supports CARB's exploration of further linkages, we urge the ARB to ensure California has in place methods of controlling the impact that one-way linkages could have on the compliance costs borne by Californians, specifically electricity ratepayers. (SOCALEDISON)

⁴⁶⁷ 2016 ISOR at 20-21 .

⁴⁶⁸ Clean Power Plan at 648943-894.

Response: Please see response to 45-day comment I-3.3, including with regard to the economic analysis ARB staff would have to conduct pursuant to the Administrative Procedure Act with respect to any future rulemaking to propose a linkage under section 95944 or section 95945.

Limitations on One-Way Linkages

I-3.6. Multiple Comments:

Linkages With Other Programs Must Be Designed to Provide the Optimum Benefit to California's Program and Not Interfere or Compromise the Ability of California Compliance Entities to Meet Their Obligations.

NCPA has long advocated for expanding California's Cap-and-Trade Program to allow for trading of compliance instruments with neighboring states and jurisdictions. Linking with other programs provides California's compliance entities with greater opportunities to seek out the most cost-effective emissions reductions possible. However, as the State has recognized, those partner jurisdictions must have programs that are equivalent to California's program. The provisions of Senate Bill (SB) 1018 set forth the minimum standards that all linked partner programs must meet. While the state should continue developing potential trading partners, actual linkages should only occur with other programs that meet *all* of the existing standards and provide California entities the same access to comparable compliance instruments from their jurisdiction as they would have to California compliance instruments. Linkages with other emissions-based programs that do not afford California compliance entities access to additional compliance instruments while allowing California compliance instruments to be retired for other than the Cap-and-Trade program should not be allowed. Further, all new linkages should continue to be subject to the same level of scrutiny, program review, and Board approval as currently exists under the Program.

Meaningful and mutually beneficial linkages provide benefits to all affected parties. However, one-way linkages have the potential to compromise the ability of California compliance entities to meet their compliance obligations and provide true value to ratepayers. In light of the tightening cap and California's uniquely aggressive and stringent climate policies, every precaution should be taken to ensure that sufficient allowances (and other compliance instruments) are available to compliance entities. Allowing those instruments to be used to meet compliance obligations totally unrelated to California's program would hinder access. Doing so also negates the value of linking as a meaningful measure to help contain program costs.

In order to ensure that linkages are indeed meaningful and would not result in unintended consequences for compliance entities, the proposed sections 95944 and 95945 must include additional direction to direct staff in evaluating a potential partnership and must also ensure that any new partners are only linked with California's program after a full review by the agency and approval by the Board. Any "Retirement-Only Agreements" with another emissions trading systems (ETS) should only be

approved after California has done a comprehensive analysis of the potential impacts the additional demand could have on California's market, including putting upward pressure on allowance prices or contributing to scarcity. Any linkages under proposed new section 95945 should also be subject to frequent review to evaluate the ongoing impacts on the California market, particularly as the cap tightens, and provisions that allow California to suspend or revoke the arrangement must be part of any Retirement-Only Agreements. (NCPA)

Comment:

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. (PG&E)

Response: Please see responses to 45-day comment I-3.3 and I-3.4.

International Linkage Accounting Standards

I-3.7. Comment:

Support following international best practices on accounting:

With only one linkage partner, Quebec, the mechanics of linkage so far have been relatively simple. However, as California engages with new linkage partners and considers new types of linkage such as Retirement-Only Linkage and Retirement-Only Linkage Agreements these relationships and their emissions impacts of them will grow increasingly complex. The Paris agreement has identified this challenge as countries consider voluntary cooperation to achieve their nationally determined contributions ("NDCs"). Article 6.2 of the Paris Agreement requires parties to "apply robust accounting to ensure, inter alia, the avoidance of double counting" when engaged in emissions trading to meet their NDCs. The Conference of the Parties will be providing further guidance to parties on what is required under this provision. Although subnational jurisdictions are not parties to the Paris agreement, California and its partners are viewed globally as a model for emissions trading and contributing to and following best practices on issues such as accounting is critical to maintaining that position. We encourage California and partners to follow developments within the Conference of Parties closely and to consider contributing to the development of best accounting practices where appropriate as the state's linkage relationships mature. EDF is deeply engaged in discussion about accounting practices under the Paris Agreement and looks forward to working with ARB on this topic in the future. (EDF)

Response: The commenter does not propose any changes to the regulatory amendments, so no further response is required. That being said, ARB staff

agrees that accounting must be conducted to avoid double counting and ensure the environmental integrity of California's and linked jurisdictions' programs.

I-4. International Sector-Based Forest Offsets

Support for Sector-Based Offsets

I-4.1. Multiple Comments:

[W]e are pleased that the state's Air Resources Board intends to consider the inclusion of greenhouse gas (GHG) reductions from tropical forests in subsequent amendments. Pursuing tropical forest credits will demonstrate California's continued commitment to practical solutions in the fight to mitigate and adapt to our changing climate. The program will not only act as a testament to your climate leadership but will also serve as a model for the inclusion of forests in future international carbon markets. As you well know, climate change is no longer an abstract future threat but is a real and present danger to ecosystems and people. Offsets from tropical forests are essential components in a comprehensive effort to reduce the worst impacts of climate change, and a successful California program can boost the prospects for gearing up a global REDD+ program.

Tropical forests play a particularly important role in stabilizing atmospheric emissions because they are the main source of terrestrial carbon emissions, they contain massive biomass carbon stocks, and improved land management policies likely can be implemented faster than a transition away from carbon intensive energy production.

California is a pioneer in the realm of international climate change and forest policy and is therefore in a unique position to incorporate REDD sector-based offset credits into its cap-and-trade program in future amendments. This will send a positive market signal to tropical forest regions around the world that, after so many years of discussions, the world is starting to gear up to fulfill the promises of REDD+...

The tropical forest jurisdictions involved in the cap-and-trade Program are mostly impoverished themselves. Yet they worked hard for many years to develop deforestation reduction programs, without much in the way of financial support, in the hope that the international community is serious about REDD+. California's new program has the potential to prove the viability of REDD+, and provide early incentives toward its expansion under the Paris Agreement in the near future...

And we will continue to work with you toward a linkage between tropical forest offsets and the state's cap-and-trade regime. (NWF)

Comment:

Support to develop a regulatory proposal for sector-based offsets from tropical forests:

Although the current proposed regulations do not include amendments to allow the use of international sector-based offsets from tropical forest for compliance in California's

program, the staff's Initial Statement of Reasons (ISOR) does contemplate this option for the program's third compliance period. We would like to take this opportunity to briefly emphasize why we believe that is critical for the State of California to develop a compliance pathway for jurisdiction-scale reductions in emissions from tropical forests through its cap and trade program, and to do so as soon as possible. First, tropical deforestation is a significant global contributor to climate change. Climate modeling suggests that reducing deforestation below current levels is crucial to stabilizing global average temperature below key thresholds above pre-industrial levels. Without economic incentives that make standing forests worth more alive than dead, the unsustainable conversion of forests worldwide is likely to continue and will further fuel the disastrous effects of climate change.

The jurisdictional and sector-based approach to crediting international offsets from the tropical forest sector being currently contemplated by CARB (i.e. one that is implemented comprehensively at state, provincial, regional, and ultimately national levels) offers critical features that overcome many of the most prominent criticisms of the project-by-project model for reducing emissions from tropical deforestation. A pathway for credits from such sector-based and jurisdictional-level programs in tropical forest jurisdictions, done right, could set a global gold standard and drive other states and countries to take action to address this significant source of global emissions. California can leverage its program to achieve emissions reductions beyond its borders at a large scale by incentivizing high-integrity programs abroad that can demonstrate reduction in deforestation emissions and benefits for tropical forest communities. In addition, an adequate supply of high-quality offsets within the regulatory offsets limit is an important cost-containment feature for California's program. (EDF)

Comment:

Regarding design of cap and trade going forward, we strongly support the continued availability of offsets and encourage ARB to continue with the effort to include sector-based tropical forestry offsets in the program. This is going to keep program costs within reasonable bounds, while keeping carbon out of the atmosphere, period. (PG&E3)

Comment:

Including Sector Based offsets. SMUD appreciates the efforts that ARB staff has undertaken to start including Sector Based Offsets in the Cap-and-Trade Program, and the stated intention of continuing to pursue such inclusion, even while not being able to include in this rulemaking. (SMUD)

Comment:

Indirect reductions are also key as part of cap and trade. And the greenhouse gas emissions offsets enable California to promote real and sustainable reductions both here in California and beyond our borders. They also promote innovation from other sectors, and we think they're very important.

We support the ARB's ongoing efforts both to increase sector-based offsets and consider tropical deforestation, as well as addressing other supply -- offset supply issues. (CHEVRON)

Comment:

IETA encourages ARB to support the inclusion of international sector-based/REDD+ offsets into California's program as early as practical and effective. For detailed input on technical and policy aspects of sector-based/REDD+ offset credits, please visit IETA's library of related 2016 submissions to ARB. (IETA)

Comment:

I would like to speak in this minute of have about climate change, and forests, leadership, international cooperation, and steps for our common future. We know that forests are critical for the climate change challenge we have today. And we know that they need to be part of the equation. So the integration of those sectoral forest climate change programs are critical also to the challenge that we are facing in our futures.

So when we think about sectoral forest programs, we don't think only about forests, we think about people and we think about changing the drivers of economy.

That's the essential of this movement. And about this movement, we know that it's essential that we do it together. It's not possible to do it alone, so we need cooperation, and we need our international cooperation.

And we need the right signs to be given to the right people that are now at this moment trying to create those new laws, those new principles, those new policies.

I think California is giving that leadership. We support that and I think we -- it's important to give that leadership, but we cannot do it alone. We need to do it in cooperation and with ends, highs with highs. We need to work together for that common goal.

So in that sense, it's very good to me to listen that you are continuing to do efforts to continue to work on the sectoral approach in the future approach. And I think that a huge amount of leaders now listen to us. It's not only this room. It's not only the people who are watching us on the Internet. The leaders are listening to us and are listening to your message for them. (LOPES)

Comment:

On behalf of EII I'd like to commend the Air Resources Board on proposing the cap-and-trade amendments. I would particularly like to point out the text on page 21 of the Initial Statement of Reasons document, which reflects that ARB staff will continue to explore the sector-based offset program, and its linkage with Acre, Brazil.

Implementing this program will not only get California on the right cost-effective track to reach SB 32's new 2030 target, but it can also provide real ben -- provide real benefits

to forest steward communities in Acre, while simultaneously mitigating the global impacts of climate change through tropical forests.

The 5th assessment report of the IPCC concludes that up to 60 percent of global abatement measures could come from the land sectors by 2030. This linkage with Acre can play a significant role in tapping into the true potential that land use can play in avoiding the impacts of climate change.

With this said, on behalf of the EII, I'd like to state that there is great value in the -- excuse me -- the Board adopting further regulations that allow for the sector-based offset program to become active in the 3rd compliance period of the Cap-and-Trade Program. (EARTHINNOVATION2)

Comment:

We also support offsets including the sector-based offsets, and the comments made by folks from Acre, Brazil. (CCEB2)

Comment:

TNC supports the inclusion of sector-based offset credits from avoided tropical deforestation at the earliest date possible

For many of the same reasons that the Conservancy supports linkages between California and other jurisdictions, like Ontario and Quebec, the Conservancy supports linkages with tropical forest jurisdictions to reduce emissions from deforestation and forest degradation and promote low carbon development. Forest loss and degradation are responsible for roughly 12% of global anthropogenic emissions,⁴⁶⁹ so we are pleased that California recognizes the critical importance of addressing this problem and providing this leadership. Through linkages with other jurisdictions to reduce emissions from forest loss and degradation, California can be a catalyst for greater action around the globe to reduce emissions from this resource, while advancing low carbon development in resource dependent communities.

Significant interest and support is coming from several tropical forest states that are members of the Governors' Climate and Forest taskforce and who are signatories to the Under 2 MOU including Acre, Brazil and others in Mexico, Brazil and Peru. Linking with these jurisdictions in some form could help these states meet their emission reduction pledges in the Under 2 MOU, reduce GHG emissions, alleviate poverty, and help indigenous communities preserve their cultural heritage and protect biodiversity.

⁴⁶⁹ G. R. van der Werf, D. C. Morton, R. S. DeFries, J. G. J. Olivier, P. S. Kasibhatla, R. B. Jackson, G. J. Collatz and J. T. Randerson, *Commentary: CO2 Emissions from Forest Loss*, Nature Geoscience, Volume 2, November 2009; See also

http://bofdata.fire.ca.gov/regulations/proposed_rule_packages/working_forest_management_plan/attachment_3_vanderwerf_co2_emissions_from_forest_loss.pdf

CARB has invested significant time researching and vetting the issue of linking with tropical forest jurisdictions and the inclusion of sector-based credits. The inclusion of tropical forest credits is specifically referenced and contemplated in the existing regulations for the cap and trade program.⁴⁷⁰ The rationale for including sector-based credits is described well in the CARB staff white paper on sector-based offset credits⁴⁷¹ and referenced in the ISOR for this proposed regulatory amendment in several places (see Chapter 2, b,4; Chapter IX; and Appendix F). As stated by CARB, adding sector-based credits to the cap and trade program would have many benefits to California. “CARB staff has presented information about how linkage with a state-of-the-art, jurisdictional sector-based offset program can provide significant benefits to California’s Cap-and-Trade Program by assuring an adequate supply of high-quality compliance offsets to keep the cost of compliance within reasonable bounds, up to the quantitative usage limit for sector-based offsets. Linkage would also support California’s broad climate goals, as well as global biodiversity and tropical forest communities.”⁴⁷² We encourage CARB to continue this process by following up on its commitment to hold additional informal public meetings outside of this rulemaking starting in the fall of 2016.⁴⁷³ (CONSERVANCY)

Comment:

For example, authorization of sector-based offsets will be critical to ensuring adequate offset supply in future compliance periods, and as ARB has observed, should be incorporated into the cap-and-trade regulation in advance of the third compliance period. (CCPC)

Comment:

And that brings me to our next point, we do support the inclusion of sector-based offsets from tropical forest protection at the earliest possible moment.

We believe that the staff has done an exceptional job of building the record for this with 4 workshops and a very comprehensive staff report. And there will – many benefits will

⁴⁷⁰ § 95992. Procedures for Approval of Sector-Based Crediting Programs. The Board may approve a sector-based crediting program in an eligible jurisdiction after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code section 11340 et seq.). Provisions set forth in this article shall specify which compliance instruments issued by an approved sector-based crediting program may be used to meet a compliance obligation under this Article. NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code. § 95993: Sources for Sector-Based Offset Credits. Sector-based credits may be generated from: (a) Reducing Emissions from Deforestation and Forest Degradation (REDD) Plans.

⁴⁷¹ California Air Resources Board Staff White Paper: *Scoping Next Steps for Evaluating the Potential Role of Sector-based Offset Credits under the California Cap-and-Trade program, Including from Jurisdictional “Reducing Emissions from Deforestation and Forest Degradation” Programs*, <https://www.arb.ca.gov/cc/capandtrade/sectorbasedoffsets/ARB%20Staff%20White%20Paper%20Sector-Based%20Offset%20Credits.pdf>

⁴⁷² *Id.* at p. 22

⁴⁷³ *Id.* at p. 21

accrue to California, including helping Governor Brown achieve the reduction pledges from states in the under 2 MOU, that Acre and other tropical forest states have pledged reductions, and reductions here will do it. (CONSERVANCY2)

Response: ARB staff appreciates the comments received in support of a jurisdictional sector-based offset program under the Cap-and-Trade Regulation. As indicated in the ISOR for this rulemaking, although any regulatory amendments related to sector-based offset crediting or tropical forests are outside of the scope of this rulemaking, ARB staff continues to view linkage with a state-of-the-art, jurisdictional sector-based offset program as an important cost containment measure for meeting compliance obligations incurred in the third compliance period and thereafter; and one that also supports California's broad climate goals and with benefits to global biodiversity and tropical forest communities. Outside of this rulemaking, ARB staff anticipates additional workshops to solicit public comments and continuing engagement with stakeholders and partner jurisdictions to move further along the regulatory path towards a successful linked sector-based offset program.

Support for Linkage with Acre, Brazil

I-4.2. Multiple Comments:

We're also supporting... moving forward with, although it's at an earlier stage, the -- accepting sectoral offset credits first step through a linkage with Acre, Brazil. (EDF2)

Comment:

I'm going to talk here from the perspective of an indigenous woman about our expectations and hopes for a partnership between State of Acre and the Brazilian Amazon and California. And I'm very glad to be here, because I know that California has really excellent work on environmental issues, just like the State of Acre.

It's very important that this work goes on and respect human rights, indigenous rights, indigenous land rights, health and well-being of local communities, and indigenous land rights.

In Acre we are not de-foresting. We are maintaining standing forest. And we need the support of California to continue doing this important work for Acre and for the world. I think that both California and Acre can be important examples internationally and help bring other countries along. The world is sick and we need to raise our consciousness about this, because these problems are affecting everyone. (LIMACOSTA)

Response: Thank you for your comment. Amendments to include a jurisdictional sector-based offset program are outside the scope of this rulemaking. However, as indicated in the ISOR for this rulemaking, ARB staff is proposing to continue discussing with stakeholders and partner jurisdictions, including Acre and others in the Governors' Climate and Forests Task Force, on

the regulatory path to optimize the multiple benefits of including sector-based offsets in California's program, including through a linkage with Acre, in time to be used to meet compliance obligations incurred in the third compliance period and thereafter.

Support for Sector-Based Offsets in Third Compliance Period

I-4.3. Multiple Comments:

EII writes in strong support of the IOP [international offsets program] as a cost-effective mechanism to achieve California's new 2030 statewide emissions reductions target, while multiplying the benefits of California's vanguard climate action agenda beyond its borders to tropical forest jurisdictions. The IOP would support linkages between California and regions critical to global climate regulation, including Brazilian Amazon states of Acre and Mato Grosso which account for more than two billion tons of CO₂ emissions reductions over the past ten years, providing much needed financial support to stave off rising deforestation rates. While some states are better positioned/prepared than others for linkage to California, the enactment of IOP would provide a much-needed signal to tropical forest regions and communities that their hard work in successfully reducing deforestation can be rewarded and will continue to be rewarded in the future.

Since its inception, we have been strong advocates of the IOP's jurisdictional approach to reducing emissions from deforestation and forest degradation (REDD+), which establishes rigorous environmental and social standards for linkage to CA and, importantly, must provide mechanisms for benefit-sharing with multiple land and resource managers across the entire jurisdiction.

Acre, is the most advanced jurisdiction-wide REDD program in the world and exemplifies the type of policies, governmental leadership, and social inclusion that would be favored by the IOP. Since 1999, the Government of Acre has been building upon the legacy of Chico Mendes, the rubber tapper and grass roots organizer who was assassinated because of his successful efforts to keep forests standing by increasing economic opportunities for its indigenous and traditional residents. Beginning with Governor Jorge Viana, who took office as Governor in 1999, the Acre Government has been translating Chico's vision into innovative policies and programs for improving the livelihoods and economic opportunities of the state's indigenous peoples, rubber tappers and smallholders.

The government of Acre has gone through a rigorous, publicly inclusive process to design the State's Environmental Service Incentive System (SISA), which has geared the Brazilian state up for effectively linking with California's offset program. EII works actively with the state of Acre to provide technical and scientific assistance for the SISA program. To learn more about SISA and how it was developed, please see the [Acre State's Progress Towards Jurisdictional REDD](#) report. EII would also like to applaud the ARB for doing their part in carrying out a deep vetting process to examine the IOP

through the REDD Offset Working Group, the Staff White paper on Sector Based Offsets, and all of the public meetings and workshops it has hosted to date.

Last April, during ARB's public workshop on social and environmental safeguard requirements for international offsets, a delegation of indigenous and tropical forest steward leaders⁴⁷⁴ participated to voice their support for the IOP and highlight the powerful benefits that these programs can have in their communities and regions. The delegates from Acre cited a number of key benefits already reaching indigenous peoples and traditional communities as a result of Acre's jurisdictional REDD+ program. Manoel Monteiro, general administrator for a cooperative representing over 2500 rubber tapping families, spoke at the workshop about how a state subsidy for rubber, financed by SISA, has improved the livelihoods and well-being of forest dwelling families. Haru Kuntanawa, leader of an Indigenous Association in Acre, described how the state government has engaged Indigenous peoples as partners in sustainable development planning, and as a result has made progress in finding the best ways to support indigenous peoples through the SISA program. While many of the other visiting leaders come from regions far less advanced in terms of jurisdictional REDD+ and potential linkage to California, many expressed hope that the minimum safeguard requirements currently being developed by California as part of IOP will set the bar high for REDD+ globally – ensuring that jurisdictional REDD can advance both climate change mitigation and protection of human rights.

These examples provide a glimpse at the kinds of changes California could support through enactment of IOP.

EII fully supports ARB's decision to maintain current offset usage limits in the proposed amendments and to continue further evaluation of the international sector based offsets program, though we urge the board to consider acting quickly to take necessary measures to implement the IOP as soon as possible so that it is operational in compliance period three of the Cap-and-Trade system.

Land use currently has the potential to provide up to 60% of total abatement measures needed by 2030.⁴⁷⁵ We are now at a pivotal moment where California can tap into the true potential that sustainable land use can play in avoiding dangerous impacts of

⁴⁷⁴ The list of these leaders can be seen as follows:

Candido Mezua – General Chief of the Emberá-Wounaan Region and Chairman of the National Coordinating Body of Indigenous Peoples of Panama (COONAPIP); Gustavo Sanchez – President-Red Mexicana de Organizaciones Campesinas Forestales (RedMOCAF); Arlen Ribeira – Administrative Coordinator, Coordinadora de las Organizaciones Indigenas de la Cuenca Amazónica (COICA); Edwin Vasquez – Coordinator General, Coordinadora de las Organizaciones Indigenas de la Cuenca Amazónica (COICA); Manoel Monteiro – General Administrator-Cooperativa Central de Comercialização Extrativista do Acre (Cooperacre); Jose Flavio Nacimiento (aka Haru Kuntanawa) – Kuntanawa Tribe, President- Socio-Cultural and Environmental Association of the Kuntamanã

⁴⁷⁵ IPCC Working Group 3. Chapter 11, Agriculture, Forestry and Other Land Use. Assessment Report 5: Mitigation of Climate Change (2014).

climate change. California's global leadership continues with the passage of SB 32 – if the state succeeds in compensating tropical forest regions and traditional forest stewards, profound mitigation impacts can be realized⁴⁷⁶ while also creating an important model for China and other jurisdictions who are developing emissions trading systems to follow. (EARTHINNOVATION)

Comment:

I write in strong support of accelerating sector-based credits for tropical forest protection within the California cap-and-trade program in time for use in the third compliance period.

California now faces the urgent, important, and globally significant challenge of reducing its greenhouse gas emissions by 40% below 1990 levels by 2030, as recently signed into law by Governor Brown. To achieve this worthy goal effectively, efficiently, and equitably, ARB will need to employ many measures, including strengthening cap-and-trade by incorporating sector-based credits for tropical forest protection. As detailed in previous public comments (e.g. "Eight reasons for California to lead on climate and tropical forests," October 2015)⁴⁷⁷ during ARB's thorough and open public consultation process, inclusion of sectoral offset credits for tropical forest protection can:

- Fight climate change abroad as well as at home
- Contain costs for California companies and their customers
- Make California the standard-setter for the world
- Provide side benefits for sustainable development goals and biodiversity conservation
- Adapt a model that has already been tested using public funds
- Support indigenous peoples' rights and aspirations
- Demonstrate that technical issues are surmountable
- Jumpstart actions in other states and provinces that could finance tropical forest protection

⁴⁷⁶ Nepstad, Swette, Horowitz. 2014. Multiplying the impact of California's Global Warming Solutions Act through International Partnerships for Tropical Forests. Earth Innovation Institute. <http://earthinnovation.org/publications/multiplying-the-impact-of-californias-global-warming-solutions-act-ab-32-through-international-partnerships-for-tropical-forests/>

⁴⁷⁷ "Eight Reasons for California to Lead on Climate and Tropical Forests." Jonah Busch. Center for Global Development Blog. October 27th, 2015. <http://www.cgdev.org/blog/eight-reasons-california-lead-climate-and-tropical-forests>

For all these reasons, ARB should accelerate the inclusion of sector-based credits for tropical forest protection within the California cap-and-trade program in time for use in the third compliance period. (CGDEV)

Comment:

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. (PG&E)

Comment:

We strongly support the staff recommendation to maintain the existing role for offsets, strongly support the staff recommendation to continue discussing the role for sector based credits, including especially, those from tropical forests, and to adopt regulations that would these types of offsets in the 3rd compliance period.

We urge you to act quickly to complete this addition to the program, and we want to point out that ARB has explored this issue extensively and has built a strong record supporting this action. The ARB staff has recommended this action many times, adding tropical forest offsets is specifically referenced and contemplated in the existing AB 32 regulations, and adding tropical forest offsets will bring many benefits to California, including:

- Helping to fulfill the directive in AB 32 to act globally;
- Contributing to fulfill the requirement in AB 32 to adopt the most cost effective mechanism to meet the reduction level;
- Providing assistance to help tropical forest states that have signed Governor Brown's Under-2-MOU meet their emission reduction pledges;

- Mitigating global climate change that is generating impacts affecting disadvantaged communities disproportionately, and adversely impacting natural resources upon which all life depends.

Please inform Forest Trends if we can provide any further information related to this matter. (FORESTTRENDS)

Response: To the extent the comments request increasing the quantitative usage limit on offsets that exists in the regulation, that provision has not been proposed for amendments in this rulemaking and the comment is outside the scope of the proposed amendments. For comments supporting the inclusion of sector-based offset credits in a future rulemaking, please see responses to 45-day comments I-4.1 and I.4.2.

Concern Regarding Sector-Based Offsets

I-4.4. Comment:

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. (PG&E)

Response: The comment is outside of the scope of the proposed amendments. ARB staff did not propose any new offset protocols as part of this rulemaking, nor did ARB staff propose any amendments to include sector-based offset crediting or tropical forests. Please see also responses to 45-day comments I-4.1 and I.4.2.

Opposition to Sector-Based Offsets

I-4.5. Comment:

Do not pursue or include reducing emissions from deforestation and forest degradation (REDD) international offsets in the Scoping Plan. (EJAC)

Response: The comment appears to be made in reference to the proposed 2017 Scoping Plan Update. To the extent it is referencing the sector-based offset crediting provisions in the Cap-and-Trade Regulation, ARB staff did not propose any amendments to include sector-based offset crediting or tropical forests in this rulemaking. As such, the comment is outside of the scope of this rulemaking.

Definitions of Sector-Based Offsets

I-4.6. Comments:

We advocated for many years in the global climate change negotiations to include social and environmental safeguards within the provisions for REDD+, which are now embodied in the Paris Agreement. Therefore our support for a California tropical forest

offset program is predicated on the inclusion of similar safeguards there, as part of the policy framework, not as voluntary guidelines. (NWF)

Response: The comment is outside the scope of the proposed amendments. Please see response to 45-day comment I-4.1.

Sector-Based Offsets Regulatory Process

I-4.7. Comment:

CMCA supports the use of increased sector-based offset credits, such as REDD, but not at the expense of the current offsets market. CMCA therefore proposes that CARB work collaboratively with the legislature and other stakeholders to solicit their support prior to proposing regulations that may solicit a negative legislative reaction towards the current offsets market. (CMCA)

Response: The comment is outside the scope of the proposed amendments. Please see responses to 45-day comments I-4.1 and I-4.2.

I-5. Miscellaneous

Support for Reducing Emissions at the U.S.-Mexican Border

I-5.1. Comment:

In addition to California emissions, also consider activities that can reduce pollution coming from across the Mexican border, to reduce emissions in the border region. (EJAC)

Response: This comment appears to be more specifically related to the proposed 2017 Scoping Plan Update. To the extent it relates to the Scoping Plan, the comment is outside the scope of this rulemaking. To the extent the comment relates to this rulemaking, staff has not proposed any amendments that would require the reduction of emissions on the Mexican border and the comment is outside the scope of this rulemaking.

Linkages Using Clean Power Plan Framework

I-5.2. Multiple Comments:

JUG members also support the state's use of the Cap-and-Trade program to demonstrate equivalence with the U.S. EPA's Clean Power Plan and suggest that the state actively pursue opportunities to link with other jurisdiction that may opt to comply with the federal rule through mass-based trading programs. (JOINTUTILITIES)

Comment:

Compliance entities will see additional benefits associated with interstate trading in the event the CPP is finalized and California's proposed plan for CPP compliance using the Cap-and-Trade Program is approved by the EPA. NCPA encourages CARB to actively

seek trading arrangements that would allow California to “link” with sister states under the CPP as soon as practicable. Not only will linkages with sister states increase the ability to cost-effectively reduce GHG emissions; it will ensure that California entities are not forced to pay twice for the carbon costs associated with imported electricity. (NCPA)

Response: ARB staff appreciates the comments received in support of using the Cap-and-Trade Program to demonstrate compliance with the U.S. EPA Clean power Plan (CPP). Commenters also encourage allowing linkage with other states’ plans to comply with the CPP. ARB staff has not proposed amendments related to linking CPP plans as part of this rulemaking, but may do so once other state plans are developed and available for evaluation, so the comments are outside the scope of this rulemaking.

Linkage with Electricity-Only Cap-and-Trade Programs

I-5.3. Comment:

ARB Should Support Potential for Linkage with Electric Sector-Only Cap-and-Trade Programs

LADWP urges ARB to more clearly express support for the potential for the use of allowances issued by jurisdictions with single-sector cap-and-trade compliance programs as California Cap-and-Trade Regulation compliance instruments. LADWP recognizes and supports ARB's interpretation of SB 1018 that any use by California covered entities of allowances issued by another jurisdiction will require a formal linkage.⁴⁷⁸ However, LADWP urges ARB not to adopt an interpretation of the linkage requirements of SB 1018 that would prevent linkage with another state's program merely because that other program covers a single sector (such as the power sector). We understand that SB 1018 requires the Governor to make a finding that the linked program's requirements "are equivalent to or stricter than those required by" the California Cap-and-Trade Regulation.⁴⁷⁹ However, this provision does not specify that an equivalent program must cover the exact same sources. For example, another state's program can be as stringent in one sector as the California program is projected to be for that sector, without also covering all other sectors. This is particularly important as other states develop plans to comply with the federal CPP or establish standalone programs to achieve state-specific GHG reduction goals.

While LADWP has outlined concerns about one-way trading above, two-way linkage with CPP states can introduce market efficiencies and substantially lower the cost of compliance for California utilities, while substantially simplifying Cap-and-Trade Regulation compliance obligations with respect to imported power. Any ARB

⁴⁷⁸ See CAL. Gov'T CODE § 12894(e) (defining link to include "an action taken by the State Air Resources Board . . . that will result in acceptance by the State of California of compliance instruments issued by any other governmental agency . . . for purposes of demonstrating compliance with then Cap-and-Trade Program).

⁴⁷⁹ Id. § 12894(f)(1).

interpretation of the linkage requirements should be made in light of the substantial efficiencies and benefits that Retirement-Only Limited Linkages and two-way linkages can provide to California ratepayers. (LADWP)

Response: ARB staff appreciates the commenter's support for ARB staff's interpretation of the SB 1018 requirements. The commenter requests that ARB allow for linkage with a single-sector cap-and-trade compliance system. ARB staff has not proposed amendments to link with any specific single-sector cap-and-trade compliance system, but ARB staff did propose as part of the 45-day amendments regulatory provisions that contemplate a more limited linkage – the Retirement-Only Limited Linkage provisions in proposed section 95944. Implementation of this type of linkage would require Board approval in a future rulemaking that specifies the types of compliance instruments issued by another GHG ETS that California entities could retire and apply towards their California obligations, any types of restrictions including offset use limits, as well as a process developed with the linked GHG ETS to facilitate and track retirements and inform ARB of the retirements. This type of Retirement-Only Limited Linkage would require SB 1018 linkage findings prior to Board approval, and would require that the other program to be compatible for linking. With respect to linkage under the CPP, ARB staff has not proposed amendments related to linking CPP plans as part of this rulemaking, but may do so once other state plans are developed and available for evaluation, so the comments are outside the scope of this rulemaking.

Industrial Assistance and Linkage

I-5.3. Comment:

CARB's Proposed Approach is Likely to Reduce the Compatibility of the Cap-and-Trade Program

CARB's proposed approach for assessing leakage risk not only threatens the durability of its allowance allocation framework, but it also undermines the ease and extent to which the California cap-and-trade program can be used as a model for other jurisdictions or integrated with similar programs to create a broader, deeper, and more efficient carbon market. CARB's commitment to these goals is clear. According to CARB,

- “the intended outcome of the harmonization and integration [with Quebec] is to enable each Party under its own legislative or regulatory authority to achieve the harmonization of its...regulation for the cap-and-trade program for reducing

greenhouse gas emissions and that such regulations will be compatible between the parties;⁴⁸⁰

- “by successfully linking cap-and-trade programs across jurisdictions and increasing opportunities for emission reductions, this linkage [with Quebec] represents another important step in California’s efforts to collaborate with other partners around the globe to address climate change;”⁴⁸¹ and
- “many others throughout the world look to adopt or mimic California’s leading policies and build similar markets for clean technologies. California is regarded as a global leader for developing successful policy solutions to deal with pressing environmental problems.”⁴⁸²

Unfortunately, CARB’s proposed approach undermines these goals. Specifically, by relying on leakage studies that use non-transparent data and methodologies, CARB’s proposed approach cannot be easily understood or replicated by other jurisdictions. Rather than rely on CARB’s approach as a model, other jurisdictions will be forced to adopt their own unique and parochial methods for determining leakage risk, which is likely to result in different treatment for similar industries and create competitive distortions between linked programs. (CSCME)

Response: The commenter states that ARB’s proposed approach to assessing leakage risk runs counter to the Cap-and-Trade Program serving as a model for or linking to additional jurisdictions. Staff has delayed implementation of a post-2020 assistance factor framework, including the use of any leakage assessment, as discussed in response to 45-day comments B-6.1, B-6.2, B-6.3 and B-6.9. With respect to California’s program serving as a model, ARB staff notes that this rulemaking would result in a linkage between California’s, Québec’s, and Ontario’s Cap-and-Trade Programs, despite differences in allocation approaches between these jurisdictions. As indicated in Attachment D to the ISOR of this rulemaking, “[a]n example of where the programs are not required to be similar is the process and timing of allowance allocations.” Since staff has delayed any post-2020 assistance factors for a future rulemaking, no further response is needed.

⁴⁸⁰ Agreement between the California Air Resources Board and The Government of Quebec Concerning the Harmonization and Integration of Cap-and-Trade Programs for Reducing Greenhouse Gas Emissions, p 4.

⁴⁸¹ Climate Change Scoping Plan, ES-4.

⁴⁸² Climate Change Scoping Plan, 3.

J. SUPPORT FOR THE PROPOSED AMENDMENTS

J-1.1. Multiple Comments:

On behalf of the National Wildlife Federation, we are writing to support the continuation and advancement of California's Cap-and-Trade program. More specifically, we urge the adoption of the proposed amendments to the cap-and-trade and market-based compliance mechanisms regulation...

We hope that California adopts the proposed amendments, and will once again be the frontrunner on climate change policy. (NWF)

Comment:

Forest Trends supports the ARB staff recommendation to revise the cap and trade program to achieve the new mandated GHG reduction levels of 40% below 1990 levels by 2030, the new level of reductions that is now required by state law and was signed last week by the Governor. (FORESTTRENDS)

Comment:

Ten years ago, California passed the Global Warming Solutions Act of 2006 (AB 32), which committed one of the world's largest economies to reducing its climate pollution to 1990 levels by 2020 (at the time, roughly a 30% projected cut compared to business-as-usual). The bill heralded a turning point in recognizing that while the risks of climate change are daunting, the solutions are not. From the outset, AB 32 drew national and international attention as a test case for whether aggressive climate action could be achieved without detriment to a large and globally connected economy.

A decade into implementation, California has passed the test. Emissions are down nearly 10% from their 2004 peak, while jobs and the economy are up. Other indicators show remarkable progress. Renewable energy is outcompeting fossil fuels. The largest manufacturing facility in California makes electric vehicles. More Californians work in the solar industry than for all of the state's utilities. And thanks to California's sustained leadership, the state captures more cleantech venture capital investment than all of Europe and China combined.

But huge challenges remain. Short-lived climate pollutants, like the methane released from the months-long leak at the Aliso Canyon natural gas storage facility, must be curbed. The state's suite of tools to reduce petroleum dependence must be strengthened and extended. And even as California makes impressive statewide gains, more must be done to ensure low-income communities and communities of color no longer bear the brunt of society's externalized pollution costs.

As the 2030 Target Scoping Plan Update Concept Paper outlines, overcoming these challenges will require a holistic and integrated strategy of which the cap-and-trade program remains a vital part. Due to a series of factors – including the success of California's complementary policies, the economic downturn following the 2008 financial

crisis, the significant decline in the emissions intensity of imported power, and enhanced federal climate policies (all of which reduced the “work” of the cap in closing the gap between business-as-usual emissions and the statewide limit) – the cap-and-trade program has thus far served largely in a supporting cast role on the path to achieving AB 32’s 2020 target.

But that will likely change on the path to achieving the far steeper reductions by 2030 ordered by Governor Brown last year and now codified in Senate Bill 32 (Pavley). Even under an aggressive complementary policy scenario, the state’s PATHWAYS modelling forecasts the cap-and-trade program will need to contribute between 100-200 million metric tons (MMT) of cumulative reductions between 2021-2030 (or about 10-20% of the total projected reductions) for California to reduce statewide emissions 40 percent below 1990 levels during that time. Absent those reductions, which the cap backstops, the state cannot be assured it will hit that mark. Absent the market signal that a strong carbon price would send throughout the economy in support of low-carbon technologies and practices, and their adoption by businesses and consumers, California’s path to decarbonization will be more difficult. And absent the significant investments that the cap-and-trade program generates to ensure clean technologies and employers take root in disadvantaged communities, California’s climate plan will be less equitable.

We accordingly strongly support ARB moving forward to establish the post-2020 cap-and-trade program. While ARB must continue to carefully evaluate the program and make adjustments as needed as part of the adaptive management plan and through the Scoping Plan, acting now will send the appropriate long-term signals to encourage investments by covered entities to reduce their emissions. (NRDC)

Comment:

Earth Innovation Institute (EII) would first like to commend the California Air Resources Board (ARB) on submitting the proposed amendments to the cap-and-trade program – a critical step forward in achieving SB 32’s newly legislated target of reducing statewide emissions 40% below 1990 levels, signed into law by Governor Brown earlier this month. (EARTHINNOVATION)

Comment:

TID supports the extension of the Cap-and-Trade post 2020 as a crucial component to help accomplish the state’s 2030 GHG emissions goals. Cap-and-Trade is the most effective means of mitigating rate impacts to our customers... To date, Cap-and-Trade has proven to minimize the cost burden felt by TID’s ratepayer owners, particularly those in disadvantaged communities. (TURLOCKID)

Comment:

ORA supports the efforts of the Air Resources Board (ARB) Staff to develop regulations for the extension of the Cap-and-Trade Program (Program) beyond 2020, while

recognizing complementary policies in California to reduce Greenhouse Gas (GHG) emissions by 2030 and beyond. (OFFICERATEPAYERADVCT)

Response: Thank you for the support.

J-1.2. Multiple Comments:

First of all, of the policies that California can choose from, cap and trade most certainly provides the most efficient and effective means of achieving real and long-term emission reductions. We support efficient programs. (CHEVRON)

Comment:

3Degrees supports ARB in its leadership to develop regulations to reduce greenhouse gas emissions, and particularly commends ARB for implementing a market-based cap and trade program that encourages the cost-effective reduction of greenhouse gas (GHG) emissions. (3DEGREES)

J-1.3. Comment:

Cal Chamber has long maintained that if designed properly a cap-and-trade program is a more cost-effective approach to achieving emissions reductions and is less likely to unfairly discriminate against certain industry sectors. (CALCHAMBER2)

Comment:

I want to express my strong support for cap and trade, and also for the Low Carbon Fuel Standard. (CALBIO2)

Comment:

So support for the cap and trade, and support for utility allocations, particularly to support the electrification transformation that we're all going to see...

You don't want to cut off that source of funds for us or for the State. So support for the cap and trade... (SMUD2)

Response: Thank you for the support. With respect to the comment from CalChamber, ARB staff agrees that the design of a Cap-and-Trade Program is an important, less costly approach to achieving emissions reductions.

J-1.4. Multiple Comments:

California has shown leadership on climate change by creating a price on carbon. (MEINZEN)

Response: Thank you for the support.

J-1.5. Multiple Comments:

SCE supports a well-designed Cap and Trade program to help the state achieve its post-2020 goals. A well-designed Cap-and-Trade Program can help keep total program costs down while achieving environmental goals. (SOCALEDISON)

Comment:

Key theme: The Joint Utility Group supports a well-designed Cap and Trade program to help the state achieve its post-2020 goals. A well designed market mechanism can keep total program costs down while achieving environmental goals. JUG generally supports the Cap-and-Trade program extension as proposed since the market design includes mechanisms to control costs including the use of offsets, appropriate linkages with other jurisdictions, and the continuation of the Allowance Price Containment Reserve (APCR). The JUG supports additional consideration of cost containment measures that will ensure market continuity and continued access to APCR allowances at a reasonable and sustainable cost. (JOINTUTILITIES)

Comment:

SMUD also supports the comments filed by the Joint Utility Group, covering the following key themes:

- A well-designed Cap-and-Trade Program to help the state achieve its post-2020 goals...

(SMUD)

Comment:

In over three years of implementation, California's cap-and-trade program has proven to be a successful part of California's suite of climate policies. Capped emissions are declining, California is adding jobs and growing the economy faster than the national average, the state is able to create more wealth with fewer emissions, Quebec and California are linked and holding quarterly joint auctions, almost all businesses have successfully complied with cap-and-trade requirements, and California communities - especially low-income, pollution-burdened communities - are seeing real benefits from cap-and-trade investments. Cap-and-trade is an essential part of achieving these outcomes because it places an absolute limit on carbon pollution and ensures that polluters are held accountable for their pollution and must include a price on carbon into their regular business decisions.

Because of this success we strongly support ARB moving forward with amendments to extend the cap-and-trade program beyond 2020 and believe this is the right time to do so. The cap-and-trade program needs certainty about future emissions reductions in order to continue providing robust incentives for reducing emissions. (EDF)

Comment:

EDF is here supporting the amendments to extend the Cap-and-Trade Program beyond 2020, because we think that cap and trade is an important part of the California climate package. It is the piece that ensures that we meet the -- it places an overall emissions limit for California and ensures that we don't exceed that carbon budget that we've set for ourselves. And for many sectors, cap and trade is the piece that has regulated carbon for the first time and is placing a price on emitting and polluting carbon. (EDF2)

Comment:

We strongly support California's goal of reducing greenhouse gas emissions in line with applicable statutory targets and executive orders, and believe that market-based climate policies, such as cap-and-trade, will be critical to achieving the deeper emission reductions required after 2020. (CULLENWARD, WARA)

Comment:

Greenhouse gases, and CO₂ in particular, are unlike other air pollution in that they do not lend themselves to mitigation through traditional air pollution control technologies, whereas particulate matter, NO_x and SO_x, can be reduced through the use of filtration, scrubbing, and other techniques to clean up the exhaust from combustion point sources. Carbon dioxide is a primary result of complete combustion. No matter how many air pollution control technologies can be outfitted on a stack, cleaning all these unintended byproducts of combustion to perfect and ideal conditions will still leave us with the same amount of CO₂ per unit of carbon in the fuel.

It follows that GHGs like CO₂ need to be targeted for reductions in a different manner altogether. Our livestock offset projects reduce GHGs in a manner that is scientifically quantified, proven and identify -- independently verified as real and permanent.

If you factor these into those charts, these emission reductions in Cushing's report, you'd see probably net reductions in GHGs. It's important to keep separate the significant health effects of criteria air pollutants that they have on our local communities from the global consequences and strategies to reduce GHGs.

When it comes to greenhouse gases, science has shown that location does not matter. These gases disperse throughout the atmosphere where they will affect our climate for dozens of years, regardless of where they were emitted.

I know that most people, including myself, would rather see fuel combustion reduced altogether. But as far as greenhouses gases goes, the Cap-and-Trade Program offers the most immediate, realistic, and cost-effective solution to meet the ambitious targets set out in SB 32.

And, of course, it's already set up. We hope to see the Board approve the program post-2020, so we can continue to spur new GHG emission reductions. (ORIGINCLIMATE)

Comment:

We do support a well-designed cap-and-trade system. And we look forward to working with the administration, with the legislature on development of a well-designed cap-and-trade system for post-2020. We believe that this is the most cost-effective way to reduce our GHG emissions and to help address global climate change. (CMTA2)

Comment:

As the world's leading international business community on climate, markets, and finance, IETA continues to be a staunch supporter of California's leadership and commitment to cap and trade and tangible market links with other jurisdictions.

As the State makes decisions on the future role and shape of California's Cap-and-Trade Program, we strongly urge the Board to support the clear and robust continuation of California's Cap-and-Trade Program post-2020.

Today, over 40 national and 20 subnational jurisdictions representing 13 percent of the globe's carbon emissions have a price, and currently use carbon pricing. Cap-and-trade programs with compliance offsets have become the predominant and preferred policy choice behind this growth. By this time next year, China, a country with deep climate partnerships and MOUs with California will launch its national Cap-and-Trade Program. And according to the World Bank by then 25 percent of the globe's GHG emissions will have a carbon price.

This growth is 3 times more than we've seen in the last 10 years. More and more countries continue to employ and deploy carbon pricing. These figures and trends tell the story. And the message is clear, harnessing the power of markets to efficiently reduce GHG emissions is working.

Stifling the market or abandoning this carefully crafted mechanism along with orphaning current and potential partner jurisdictions simply cannot be an option for California post-2020. The climate costs are too high, the socioeconomic costs are too high, and the leadership costs are too high.

Lastly, we'd like to align ourselves with the comments of Supervisor Gioia before, as well as Alex Jackson from NRDC. (IETA2)

Comment:

CCEEB supports a well-designed Cap-and-Trade program as the most economically efficient and environmentally effective policy for California to achieve statewide greenhouse gas emission reductions. With SB 32 now law, CCEEB believes that an additional emphasis on Cap-and-Trade is necessary to achieve cost-effective emission reductions and to send a clear market signal to achieve the 2030 reduction goal. Additionally, Cap-and-Trade provides needed flexibility for compliance entities and the potential to export the policy to other jurisdictions through linkage or sector-based offsets. (CCEEB)

Comment:

IETA made some great points and we'd like to associate our comments with them.

In addition to that, CCEEB is supportive of cap and trade as an economically efficient mechanism to achieve California's 2020 and 2030 goals.

Cap and trade is a long-term program. We can't allow temporary short-term market wobbles to influence a tightening of the market at this time. We need to stay the course, as this will allow us to achieve the international partnerships and mechanisms needed to advance climate change mitigation throughout the world beyond the California borders, which is incredibly important. This isn't just about this State. This is about averting world climate change.

That said, we think it's important to examine some of the various mechanisms, such as trade exposure while other jurisdictions are not following, and to continue that course. And we'll continue to work with staff as we move forward on that...

And finally, on a political note, we did have an interesting session. AB 197 has been mentioned a couple of times. I asked the clerk to distribute a letter from Assembly Member Eduardo Garcia. Last line of that letter indicates it's not his intent to preclude the ARB from adopting a market-based mechanism, such as cap and trade.

He testified to not wanting to eliminate the cap and trade.

And to that end, we support that and will continue to work with the legislature moving forward in future sessions and the administration. (CCEEB2)

Comment:

The Conservancy supports the continued use of the regulatory cap and trade program as a mechanism to achieve the state's 2030 reduction goals

The Conservancy supports the regulatory cap and trade program among a suite of measures being implemented to achieve California's 2020 and 2030 GHG reduction goals. While the majority of emission reductions in the state are being achieved through other programs, the cap and trade program remains a critical part of the state's climate strategy as it provides the declining cap on economy-wide emissions, ensuring that absolute GHG reductions are achieved. This attribute is distinct from the other programs designed to reduce emissions. The flexibility to trade emissions permits and invest in offsets, achieves overall GHG reductions at the lowest cost, reducing potential impacts to the economy and California consumers. The program has successfully kept the state on track to meet 2020 GHG reduction goals, and likewise, will help the state meet its 2030 goals.

While the program is not intended to generate revenue, the auction proceeds from the program have provided additional GHG reduction benefits, as well as many critical public and environmental co-benefits for California communities around the state.

Community investments range from urban forestry, to low-income weatherization, affordable transit-oriented development, forest health, low carbon transit, and wetland restoration, among others.⁴⁸³ (CONSERVANCY)

Comment:

We are here to support the proposed Cap-and-Trade Regulation, and the continued use of it to meet the State's 2020 and 2030 reduction goals.

We've heard a lot about the benefits of cap and trade. One of those I want to highlight is the safeguard mechanism. It's the backstop. If the regulatory measures don't produce the reductions, the cap and trade will pick them up. It's also cost effective, and it can capture emission reductions from uncapped sectors like forestry.

And while the clearer goal of the program is to reduce greenhouse gas emissions, it is not specifically intended to generate revenue. But the auction proceeds from the program have provided additional greenhouse gas benefits and very many critical and important public benefits, including urban forestry, low-income weatherization, affordable transit-oriented development, forest health, low-carbon transit, and wetland restoration among others. (CONSERVANCY2)

Comment:

The Climate Trust supports the Air Resources Board's efforts to maintaining a robust market mechanism as an essential and cost-effective approach to achieving California's greenhouse gas emission reduction goals. (CLIMATETRUST)

Comment:

SDG&E appreciates the changes to the regulation that make compliance and reporting less burdensome including registration, disclosures and provisions in the cap-and-trade regulation that will allow the cap-and-trade program to satisfy Environmental Protection Agency requirements for the Clean Power Plan. SDG&E supports the continuation of the cap-and-trade program with its proposed measures to control costs including offsets, linkages with other jurisdictions, allocation of allowances to electric distribution ratepayers, continuation of the Allowance Price Containment Reserve (APCR), and the ability to borrow from future years to fill the APCR if necessary. (SDGE)

Comment:

At the state level, LADWP supports ARB's efforts to develop new regulations to implement the ambitious post-2020 emissions reduction goals of the California Cap-and-Trade Regulation and appreciates the opportunity to submit these comments to improve the effectiveness and workability of ARB's regulatory proposal. (LADWP)

⁴⁸³ See <https://arb.ca.gov/cc/capandtrade/auctionproceeds/auctionproceedsmap.htm>

Comment:

NCPA believes that the Cap-and-Trade Program has played a critical role in the success of California's climate change objectives. (NCPA)

Comment:

And NCPA and MSR support continuation of the Cap-and-Trade Program. (NCPA2)

Response: Thank you for the support.

J-2. Post-2020 Authority

Support for Post-2020 Authority

J-2.1. Multiple Comments:

Authority to Act

AB 32 gave the Air Resources Board the responsibility and obligation to regulate greenhouse gas pollution in California. Although, AB 32 set out a specific target for 2020, the language of AB 32 is clear that the Board's responsibility does not end in 2020. Therefore, EDF has been fully supportive of ARB's efforts to extend the cap-and-trade program beyond 2020 under their existing AB 32 authority. Furthermore, the California Legislature has now made it clear, through the recently passed SB 32, that ARB does have existing authority to act to reduce greenhouse gasses and that they must use that authority to reduce harmful pollution consistent with reaching a target of at least 40 percent below 1990 levels by 2030. (EDF)

Comment:

Legal Authority

We fully concur in ARB's legal assessment underpinning this rulemaking that ARB has authority to extend the cap-and-trade program beyond 2020 in furtherance of achieving California's 2030 and 2050 greenhouse gas reduction goals. AB 32 requires ARB to not only achieve the statewide limit of returning to 1990 emissions levels by 2020 but to continue and maintain reductions thereafter – and SB 32 mandates that ARB use that authority to ensure emissions are reduced to at least 40 percent below 1990 levels by 2030. By imposing an economy-wide limit on emissions, the cap-and-trade program is uniquely situated as a regulatory tool to ensure ARB achieves the 2030 target in SB 32 in the most cost-effective manner. No other provision of law prevents ARB from continuing its role as a backstop to the larger suite of policies that will be developed in the update to the Scoping Plan.⁴⁸⁴ (NRDC)

⁴⁸⁴ Health & Safety Code § 38562(c) is written in permissive terms to clarify that ARB *could* adopt a cap-and-trade program applicable from 2012 to 2020 under its AB 32 authority; having elected to do so, it does not restrict ARB's authority to continue the program after 2020.

Comment:

ARB Possesses Ample Legal Authority to Extend the Cap-and-Trade Program Beyond 2020

Calpine supports ARB as it moves forward with the Cap-and-Trade Regulation beyond 2020, both in recognition of the important achievements made by the program in fulfilling the principal goal of AB 32 and on the basis of the ample legal authority provided by existing law to achieve reductions beyond the statewide greenhouse gas emissions limit through the use of market-based compliance mechanisms.

The Legislature has expressly charged ARB with the obligation of “regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.”⁴⁸⁵ And, pursuant Section 38551(b) of the Health and Safety Code, the Legislature has expressed its intent that the statewide greenhouse gas emissions limit be used to maintain and continue reductions beyond 2020. Consistent with this existing statutory authority, the Legislature recently passed, and the Governor signed into law, Senate Bill 32 (“SB 32”) and Assembly Bill 197 (“AB 197”), which confirm that ARB shall utilize the statewide greenhouse gas emissions limit to continue reductions at least 40 percent below the limit by December 31, 2030.⁴⁸⁶

Pursuant to ARB’s authority to revise regulations and adopt additional regulations to further the provisions of Division 25.5 of the Health and Safety Code (i.e., AB 32), including market-based compliance mechanisms,⁴⁸⁷ and consistent with the statutory directives outlined above, Calpine believes that ARB has ample legal authority to move forward with continued implementation of the Cap-and-Trade Regulation beyond 2020.⁴⁸⁸

As indicated in the proposed Compliance Plan for the Clean Power Plan, ARB “is designated the air pollution control agency for all purposes set forth in federal law. . . . [ARB further] is designated as the state agency responsible for the preparation of the state implementation plan required by the Clean Air Act (42 U.S.C., Sec. 7401, et seq.) . . . ”⁴⁸⁹ Under this authority, ARB will be required to develop and implement the state implementation plan to achieve the Clean Power Plan’s requirements for California, which are applicable starting in 2022. And, as recognized in the Clean Power Plan itself, existing multi-sector state measures such as the Capand-Trade Regulation may be utilized as the Clean Power Plan compliance measure for the state. Therefore,

⁴⁸⁵ Health and Safety Code Section 38510.

⁴⁸⁶ Id. Section 38566.

⁴⁸⁷ See id. Sections 38560, 38562(a) and 38562(g).

⁴⁸⁸ See also Assem. E. Garcia, Legislative Intent – Assembly Bill No. 197, Assem. J. (2015-2016 Reg. Sess.) p. 6587, <http://clerk.assembly.ca.gov/sites/clerk.assembly.ca.gov/files/adj083116.pdf> (“AB 197 adds Section 38562.5 to the Health and Safety Code, within Division 25.5 (i.e., AB 32). . . . It is my intent that nothing in Section 38562.5 shall be interpreted to preclude ARB from adopting any market-based compliance mechanism pursuant to AB 32.”).

⁴⁸⁹ Health and Safety Code Section 39602.

separate from the existing statutory authority authorizing ARB to continue implementing the Cap-and-Trade Regulation to achieve California's emission reduction targets, ARB is statutorily mandated to implement an effective program that will fulfill the requirements of the Clean Power Plan through 2030 and beyond.

Calpine believes that, recognizing the integral role played by the Cap-and-Trade Regulation in EPA's development of the Clean Power Plan, the Cap-and-Trade Regulation's continued implementation as an integral component of California's Compliance Plan is wholly fitting, reasonable, and well-within ARB's statutory authority. (CALPINE)

Comment:

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. (PG&E)

Comment:

IETA applauds ARB's recognition that a fully-functional market mechanism is a vital, cost-effective cornerstone tool in California's climate policy architecture. We fully support the agency's post-2020 commitment to extend California's Cap-and-Trade program, along with all major provisions to ensure greenhouse gas (GHG) emissions reduction certainty into the future. (IETA)

Comment:

ICE Futures US (IFUS) and ICE Clear Europe (ICEU) write this comment letter in support of the cap and trade program operated by the California Air Resources Board (ARB) and with the aim of participating directly in the CITSS system in order to facilitate trading and clearing of California Carbon Allowances. (ICE)

Comment:

MID supports a cost-effective, market-based system to drive carbon reductions. SB 32's greenhouse gas (GHG) emissions target of 40% below the 1990 emissions level by 2030 is ambitious, but also onerous; meeting this target will require significant investment in emissions reduction technologies and processes by all sectors. It is important that the markets are allowed to dictate the most cost-effective means of

reducing emissions to avoid inefficient investments and high costs to Californians. A well-designed Cap-and-Trade program, with provisions in place to prevent snowballing costs, is the preferred method of shepherding California towards its environmental goals over the coming decades. (MODESTOID)

Response: Thank you for the support. ARB agrees that pursuant to AB 32 and AB 398, it has legal authority to continue implementing the Cap-and-Trade Program after 2020. See response to 45-day comment K-1.8 for more detail on legal authority.

K. OPPOSITION TO THE PROPOSED AMENDMENTS

K-1.1. Comment:

The Climate Change Policy Coalition (CCPC) is a coalition of business and taxpayer groups working for effective implementation of California's climate policies (AB 32 and SB 32). CCPC represents regulated entities subject to the cap-and-trade program, and our goal is to provide a constructive voice in how program improvements are proposed and design element updates are adopted by the California Air Resources Board (ARB).

CCPC believes that the cap-and-trade program can become an effective regulatory program to reduce emissions in a cost effective manner that maintains the competitiveness of California's businesses – but how that's done can make or break California's economy.

Currently, the cap-and-trade regulation contains numerous issues that need resolution prior to the next time the Board considers the final proposed amendments to the cap-and-trade Regulation. These issues include design flaws, which should be addressed in the regulatory amendments. (CCPC)

Response: The commenter has expressed statements of concern about various parts of the amendments, but without sufficient detail to enable a more detailed response. ARB staff suggests that to the extent the commenter has more specific comments, those may be addressed elsewhere in this FSOR.

K-1.2. Comment:

We do not support Cap and Trade because it places unjust burdens on low-income communities and communities of color. Climate change solutions must protect all Californians, starting with those already overburdened by air pollution and climate change.

Cap and Trade ignores the reality that location matters and disproportionately harms communities of color and low income communities. Reductions of greenhouse gases on-site reduce co-pollutants, such as fine particulate matter (PM2.5) and air toxics, emitted into the surrounding community – a benefit that is forgone when that facility buys allowances or offsets. At worst, co-pollutants increase when a facility increases its greenhouse gas pollution. Over two-thirds of California's low-income African Americans

and about 60% of low-income Latinos and Asian/Pacific Islanders live within six miles of a Cap and Trade facility.⁴⁹⁰

[The commenter attached, as Exhibit 1, referred to in the preceding footnote, a Hewlett Foundation-funded report by called “Minding the Climate Gap: What’s at Stake if California’s Climate Law isn’t Done Right and Right Away.”]

Cap and trade is like a house built on a foundation of sand. The recent collapse of the allowance market, with a vast oversupply of allowances, exposes the inadequacy of Cap and Trade where so much of the “reductions” have occurred through heavy use of offsets (mostly out of state) and changes in imported electricity. See Section I, *infra*. Further, refinery emissions data show increased emissions in several communities during the first compliance period⁴⁹¹ while many of those refineries are among the Top-10 users of those offsets.⁴⁹² All of this comes at the undeniable expense of those communities living amongst these major sources of greenhouse gas and co-pollutant emissions...

[The commenter attached, as Exhibit 2, referred to in the footnote prior to the preceding footnote, tables showing California refinery GHG emissions changes from 2011-2012 to 2013-2014.]

The threats posed by climate change to our health, communities and livelihoods are permanent and real, and so must our efforts to stop these threats be permanent and real. Cap and Trade, with pollution trading and heavy use of questionable and mostly out-of-state offsets cannot accomplish this objective. The facts unequivocally demonstrate that Cap and Trade, with all of its loopholes, distortions, and exceptions does not “work” and does not reflect the kind of equitable and just approach we need to solve our climate problems. The State Board’s goals of low-cost and flexibility should never trump environmental justice values or the collective statutory schemes of AB 32, SB 32, and AB 197, all of which call for climate policy with environmental justice at its core. (JOINTENVJUSTICE)

Response: Greenhouse gases (GHGs) are global pollutants that do not pose direct health risks as criteria and toxic air pollutant emissions do. ARB staff agrees that reducing exposure to criteria and toxic air pollutant emissions is necessary to protect residents in disadvantaged communities. However, the Cap-and-Trade Program is chiefly a mechanism for limiting climate change-causing GHG pollution. Moreover, as indicated in the annually reported and verified GHG emissions data, GHG emissions have been declining statewide since the adoption of the Cap-and-Trade Program. Indeed, as the Cap-and-Trade Program covers 85 percent of the GHG emissions in the State and given

⁴⁹⁰ Manuel Pastor, *et. al*, Minding the Climate Gap (2010) at 9, Figure 2, attached as Exhibit 1.

⁴⁹¹ California Environmental Justice Alliance, Summary of Refinery Emissions Data, attached as Exhibit 2.

⁴⁹² California Environmental Justice Alliance, Top 10 Offsets Users in California, available at <http://caleja.org/2016/02/stop-redd-from-harming-communities-locally-and-globally/>

that the emissions cap declines every year, there necessarily are direct emissions reductions from sources subject to the Regulation. Additionally, the more stringent GHG cap post-2020 means that GHG emissions will be reduced to an even greater extent for the 2021-2030 period. Please refer to response to 45-day comment K-1.5 for more detail.

K-1.3. Multiple Comments:

So far cap and trade has not been working. We no longer want pollution trading. My community health is being impacted because of all the pollution that industries located near homes are bringing. Pollution trading allows big polluters by cheap credits or banked credits they got for free so they can pollute instead of cleaning up themselves. (LEADERCOUNSEL)

Comment:

The trade of contamination is the wrong way in which California reaches the -- meets the requirements -- the federal requirements for the plan of clean energy. We need reductions of direct contamination and a just transition of energy in our communities. Please, we don't want you to negotiate with our health. It is something that has no price. The clean energy plan requires that communities of environmental justice will get involved in a positive way. That means that the opinions of community must be taken into consideration when decisions are being made. Cap and trade was adopted several years ago, and it does not have the voice of the most affected communities. We need a true voice for us that will tell you how energy plants must be regulated, and also have better quality of air. (TRUJILLO)

Comment:

I'm here today to speak against pollution trading, because pollution trading, as many have mentioned, has an impermissible racially discriminatory impact on California's communities of Color, who have been long overburdened by pollution, not just air toxics like we're talking today, but always other forms of pollution. So please take into consideration the cumulative impacts that these communities face. Pollution trading allows the State's largest emitters, who are already concentrated disproportionately in communities of color, to buy cheap credits. As Gema mentioned, it costs 5 times the amount to buy an Albuterol inhaler than it does to buy a ton of carbon. A new report that folks have mentioned from the California Environmental Justice Alliance shows that while overall greenhouse gas emissions are down from peak in 001, many sectors, like oil and gas, which many folks have spoken about already, greenhouse gas emissions are actually up under the trading program. Communities within 2.5 miles of a greenhouse gas emitting facility have a 22 percent higher proportion of people of color, and a 21 percent higher proportion of low income people. Respectfully, the Board should reject pollution trading, because it continues to exacerbate the legacy pollution in low income and communities of color. All Californians deserve and are entitled to clean

air. And our climate policy must reach and prioritize those already most impacted by pollution. (CENTRACEPOENV3)

Comment:

I simply want to align my comments with Center on Race, Poverty, and the Environment. CEJA, CBE, and Pacoima Beautiful, and most importantly the many residents who joined us today, and, you know, adding to that group of residents, we work with CRPE with a cohort of climate justice and environmental justice champions in from Kern through Merced counties. And half of them did not join us here today, because they're leading the conversation with EPA and OEHHA in Fresno on CalEnviroScreen. But they would also, I think, echo the concerns with cap and trade around its disproportionate impacts on communities of color and lower income communities.

We look forward to working with you and many others on a better solution to climate. (LEADERCOUNSEL2)

Comment:

And, you know, in sum overall of my comments, I want to say please give California a plan past 2020 that does not include trading... (GAIA2)

Comment:

And I am against the cap and trade too. They're getting free passes like free credits. But if they don't use them, they're going to sell them. I wish to have my company and I can buy it and make money, but these places are making money against our health. (MENDEZ)

Comment:

And you have evidence, you have a strong research study, you have years of research that shows why trading is not the best route. And you had community members years ago who urged you, pleaded with you that this was not the way to go, to put the health of their children, to put the health of their families and their communities before trading. And you had the urging of the community members, but not just that, but now you have these really great research studies -- let me just finish this one sentence. So if you move forward with this -- with this trading, you're basically ignoring the people. You're ignoring the research, you're ignoring the data, and you're ignoring the better alternatives. (CENTRACEPOENV6)

Response: The commenters raise concerns with the use of a Cap-and-Trade Program to achieve GHG reductions, including some general assertions that the Program is not working. In initially promulgating the Cap-and-Trade Regulation, ARB balanced the considerations indicated in AB 32, including considering cost-effectiveness and ensuring that activities undertaken to comply do not disproportionately impact low-income communities. The ability for covered

entities in the Program to buy and sell compliance instruments is an important cost-effectiveness mechanism to achieve emissions reductions statewide at a lower cost than if the Program imposed emissions caps on every individual source. Moreover, and contrary to some commenters' assertions, as indicated in the annually reported and verified GHG emissions data, GHG emissions have been declining statewide since the adoption of the Cap-and-Trade Program. Indeed, as the Cap-and-Trade Program covers approximately 85 percent of the GHG emissions in the State and given that the emissions cap declines every year, there necessarily are direct emissions reductions from sources subject to the Regulation.

In addition, as mentioned in the ISOR and the Second Notice of Public Availability of Modified Text for this rulemaking, the proposed 2017 Scoping Plan Update includes the extension of the Cap-and-Trade Program post-2020. The Program has a four-year-long record of auctions and successful compliance, and in the face of a growing economy, dry winters, and the closing of a nuclear power plant, it is delivering GHG reductions. The 2017 Scoping Plan Update process referenced in the ISOR includes an economic analysis, which clearly demonstrates that the most secure, reliable, and feasible clean energy future for California—one that will continue to provide crucial investments to improve the quality of life and the environment in disadvantaged communities—partially lies in extending the Cap-and-Trade Program through to 2030. Additionally, staff analyzed alternatives to extending the Cap-and-Trade Program post-2020 in the ISOR and found that none were as or more effective than implementing a cap-and-trade program for achieving the goals of AB 32. Finally, the more stringent GHG cap post-2020 means that GHG emissions will be reduced to an even greater extent for the 2021-2030 period.

Finally, ARB staff is not aware of any evidence demonstrating that localized toxic and criteria air pollutant emissions are increasing as a result of the Cap-and-Trade Program. Some of the comments request that ARB not move forward with any of the proposed amendments. For the reasons expressed in this response, ARB staff declines to make changes to this rulemaking that would cease the amendments or the Program. Please refer to response to 45-day comment K-1.5 for more detail.

K-1.4. Multiple Comments:

Cap-and-Trade must be eliminated. (EJAC)

Comment:

I'm here today on behalf of my organization to show support for the EJAC's recommendations, and to oppose the extension of cap and trade beyond 2020. I'm going to defer comments on that point to the excellent and data-driven information we've already heard today. (GAIA2)

Comment:

I am opposed to an extension of the cap-and-trade beyond 2020. Mostly I'm opposed to the trade part of the equation. I'm fine with caps that become increasingly more restrictive over time and which apply to all sources of pollutant emissions. I believe that the trade part of the equation has undermined the effectiveness of the whole system. Modifying pollution as an allowance and allowing market exchanges of carbon credits has resulted in numerous unintended consequences. It has contributed to a substantial utility related leakage of greenhouse gases to other states. It has resulted in continuing and substantial localized air pollution in poor communities of color. It has given rise to a carbon emission monetary valuation that's way below the actual cost -- the actual cost of carbon-related emissions to the broader community, both human and non-human alike. (WURU)

Response: Please refer to ARB's response to 45-day comment K-1.3 above.

K-1.5. Multiple Comments:

We request that ARB reject the staff's recommendation to continue the cap-and-trade program post-2020. The reasons for our request are outlined in more detail below.

1) Analysis of ARB's data from the 2013-14 compliance period prove that localized increases in GHG emissions are happening, and more often in environmental justice communities. Last week, together with leading researchers, we released a report assessing the inequalities in the location of greenhouse gas-emitting facilities and the amount of greenhouse gases and particulate matter ("PM10") emitted by facilities regulated under Cap and Trade.⁴⁹³ The report also provides a preliminary evaluation of changes in localized greenhouse gas emissions from large point sources since the advent of the program. The report found:

- a) On average, neighborhoods with a facility within 2.5 miles have a 22 percent higher proportion of residents of color and 21 percent higher proportion of residents living in poverty than neighborhoods that are not within 2.5 miles of a facility.
- b) These communities are home to a higher proportion of residents of color and people living in poverty than communities with no or few facilities nearby. Indeed, the higher the number of proximate facilities, the larger the share of low-income residents and communities of color.
- c) The neighborhoods within 2.5 miles of the 66 largest greenhouse gas and PM10 emitters have a 16% higher proportion of residents of color and 11% higher proportion of residents living in poverty than neighborhoods that are not within 2.5 miles of such a facility.

⁴⁹³ Lara J. Cushing, et al., A PRELIMINARY ENVIRONMENTAL EQUITY ASSESSMENT OF CALIFORNIA'S CAP AND TRADE PROGRAM.

d) The first compliance period reporting data (2013-2014) show that the cement, instate electricity generation, oil & gas production or supplier, and hydrogen plant sectors have increased greenhouse gas emissions over the baseline period (2011-2012).

e) The amount of emissions "offset" credits exceed the reduction in allowable greenhouse gas emissions (the "cap") between 2013 and 2014 and were mostly linked to projects outside of California.

The report demonstrates three fundamental points that environmental justice advocates have raised for years:

a) Cap and Trade disparately affects communities of color compared to communities that do not host a cap and trade facility;

b) Cap and Trade denies communities the benefits of on-site reductions;

c) greenhouse gas reductions attributed to Cap and Trade occur primarily outside of California.

The report concludes: Preliminary analysis of the equity and emissions impacts of California's cap-and-trade program indicates that regulated GHG emission facilities tend to be located in neighborhoods with higher proportions of residents of color and those living in poverty. There is a correlation between GHG emissions and particulate matter levels, suggesting a disparate pattern of localized emissions by race/ethnicity and poverty rate. In addition, facilities that emit the highest levels of both GHGs and particulate matter are similarly more likely to be located in communities with higher proportions of residents of color and those living in poverty. This suggests that public health and environmental equity co-benefits could be enhanced if there were more GHG reductions among the larger emitting facilities that are located in disadvantaged communities. Currently, there is little in the design of cap-and-trade to insure this set of localized results. Moreover, while the cap-and-trade program has been in effect for a relatively short time period, preliminary evidence suggests that in-state GHG emissions from regulated companies have increased on average for several industry sectors and that many emissions reductions associated with the program were located outside of California. Large emitters that might be of most public health concern were the most likely to use offset projects to meet their obligations under the cap-and-trade program.⁴⁹⁴

The staff report, when talking about adaptive management, said that "ARB is committed to promptly developing and implementing appropriate responses" to any adverse impacts. Based on the recent findings now is the time to adjust strategies to ensure inequitable burdens are alleviated, and the proposed amendments do not achieve this. (CEJA)

⁴⁹⁴ Lara J. Cushing, et al., A PRELIMINARY ENVIRONMENTAL EQUITY ASSESSMENT OF CALIFORNIA'S CAP AND TRADE PROGRAM at 7-9, attached as Exhibit 3.

Comment:

Last week, the California Environmental Justice Alliance released a report assessing the inequalities in the location of greenhouse gas-emitting facilities and the amount of greenhouse gases and particulate matter (“PM10”) emitted by facilities regulated under Cap and Trade.⁴⁹⁵ The report also provides a preliminary evaluation of changes in localized greenhouse gas emissions from large point sources since the advent of the program. The report found:

On average, neighborhoods with a facility within 2.5 miles have a 22 percent higher proportion of residents of color and 21 percent higher proportion of residents living in poverty than neighborhoods that are not within 2.5 miles of a facility.

These communities are home to a higher proportion of residents of color and people living in poverty than communities with no or few facilities nearby. Indeed, the higher the number of proximate facilities, the larger the share of low-income residents and communities of color.

The neighborhoods within 2.5 miles of the 66 largest greenhouse gas and PM10 emitters have a 16% higher proportion of residents of color and 11% higher proportion of residents living in poverty than neighborhoods that are not within 2.5 miles of such a facility.

The first compliance period reporting data (2013-2014) show that the cement, in-state electricity generation, oil & gas production or supplier, and hydrogen plant sectors have increased greenhouse gas emissions over the baseline period (2011-2012).

The amount of emissions “offset” credits exceed the reduction in allowable greenhouse gas emissions (the “cap”) between 2013 and 2014 and were mostly linked to projects outside of California.

The report raises significant concerns and discloses new data that should foreclose the Air Board from extending the Cap and Trade program. The report demonstrates three fundamental points that environmental justice advocates have raised for years: (1) Cap and Trade disparately affects communities of color; (2) Cap and Trade denies communities the benefits of on-site reductions; and (3) greenhouse gas reductions attributed to Cap and Trade occur primarily outside of California.⁴⁹⁶ It concludes:

“Preliminary analysis of the equity and emissions impacts of California’s cap-and-trade program indicates that regulated GHG emission facilities tend to be located in neighborhoods with higher proportions of residents of color and those living in poverty.

⁴⁹⁵ Lara J. Cushing, *et al.*, A PRELIMINARY ENVIRONMENTAL EQUITY ASSESSMENT OF CALIFORNIA’S CAP AND TRADE PROGRAM, attached as Exhibit 3.

⁴⁹⁶ Claimed reductions from imported electricity generation remain suspect given the State Board’s creation of safe harbor exemptions from the resource shuffling prohibition, which allow greenhouse gas emissions to continue in fact as leakage. See Danny Cullenward, *Bulletin of the Atomic Scientists*, 2014, Vol. 70(5) 35–44, attached as Exhibit 4.

There is a correlation between GHG emissions and particulate matter levels, suggesting a disparate pattern of localized emissions by race/ethnicity and poverty rate. In addition, facilities that emit the highest levels of both GHGs and particulate matter are similarly more likely to be located in communities with higher proportions of residents of color and those living in poverty. This suggests that public health and environmental equity co-benefits could be enhanced if there were more GHG reductions among the larger emitting facilities that are located in disadvantaged communities. Currently, there is little in the design of cap-and-trade to insure this set of localized results. Moreover, while the cap-and-trade program has been in effect for a relatively short time period, preliminary evidence suggests that in-state GHG emissions from regulated companies have increased on average for several industry sectors and that many emissions reductions associated with the program were located outside of California. Large emitters that might be of most public health concern were the most likely to use offset projects to meet their obligations under the cap-and-trade program.”⁴⁹⁷

[The commenter attached, as Exhibit 3, a report by Lara Cushing et al. titled "A Preliminary Assessment of California's Cap-and-Trade Program."]

The State Board has to date not taken action to assess or prevent these impacts, and instead has consistently demonstrated its intent to prevent the public from accessing facility-specific climate data. When promulgating the Cap and Trade regulations in 2011, the State Board claimed that it would assess and prevent adverse impacts through an Adaptive Management Plan. The Initial Statement of Reasons (“ISOR”) admits that to date, the State Board has not finalized or implemented the Adaptive Management Plan. ISOR at 302. Moreover, the State Board has taken the position that the public may not access critical Cap and Trade compliance and trading data, claiming that compliance with Cap and Trade constitutes “confidential business information.”⁴⁹⁸...

[The commenter attached, as Exhibit 5, referred to in the preceding footnote, an email exchange between Brent Newell of CRPE and ARB regarding emissions data. The report contains the quote given above. The commenter also attached, as Exhibit 4, referred to in the earlier footnote, an article by Danny Cullenward titled “How California’s Carbon Market Actually Works,” published in Bulletin of the Atomic Scientists.]

The recent report highlights the disparity and impacts of the current Cap and Trade Program. Rather than perpetuate this injustice, we urge the State Board to reject the Proposed Amendments extending the Cap and Trade program beyond 2020.
(JOINTENVJUSTICE)

Comment:

Further, as you talked about briefly this morning, we've all seen the report that was released by the California Environmental Justice Alliance last week. It's findings confirm

⁴⁹⁷ Lara J. Cushing, *et al.*, A PRELIMINARY ENVIRONMENTAL EQUITY ASSESSMENT OF CALIFORNIA’S CAP AND TRADE PROGRAM at 7-9, attached as Exhibit 3.

⁴⁹⁸ See, e.g. Email from Edie Chang to Brent Newell, dated August 19, 2015, attached as Exhibit 5.

what environmental justice advocates have said for many years, and it reaffirms my belief that data is sometimes unfortunately a few years behind the live experience in these communities. We know that polluters are more likely to be located in communities of color and low income areas, and that large polluters are using credits and offsets to be compliant rather than reducing emissions at the source. We can no longer deny that cap and trade is allowing pollution to continue, and at times increase in our communities. For centuries our world's progress has largely been made on the backs of people of color and low income communities. AB 32 was developed to intentionally confront that dynamic when it linked climate policy with environmental justice. Cap and trade doesn't meet that mandate. And we're here to strongly encourage ARB to consider alternatives that allow us to breathe healthier air for everybody. (EJAC2)

Comment:

And we're here in opposition to the extension of the Cap-and-Trade Program, and to urge you as the Air Resources Board to actually halt this process until we can have a more thoughtful and fully engaging dialogue with all sectors, including the environmental justice community about how to meet our 2030 greenhouse gas emission reduction targets. The results of the report issued by Manuel Pastor, Rachel Morello-Frosch, and others clearly outline major environmental justice issues in the Cap-and-Trade Program. There have not been localized in-State emission reductions. Major greenhouse gas facilities are disproportionately located in environmental justice communities. And there are also serious concerns about the offsets program. And we would argue along with the allowances as well that are creating loopholes for our largest corporations in the world to continue operating facilities that we know are contributing to climate change and detrimental health impacts in environmental justice communities. (CEJA2)

Comment:

And I'm here today, as I was in 2008, urging the Board not to move forward with cap and trade. Basically, it's as simple as the fact that cap and trade ignores the fact that location does matter. Climate change is global, but there are real localized health issues with how we decide to move forward with how we're dealing with greenhouse gas emissions. We cannot ignore the data that has come out from the report. It is clear that pollution trading is allowing big polluters that are concentrated in environmental justice communities off the hook with allowances and offsets. And what -- what I'm here, and I'm just going to say quickly, so that there's time for everyone, is that I'm urging the Board to really take a look at that data, take a look at that report from Pastor and others. (CENTRACEPOENV2)

Comment:

Why am I opposed to the extension of the cap and trade past 2020? It is because it doesn't sufficiently require polluters to absorb the full social and environmental cost that are associated with commodity production. An example that Shana Lazerow gave of the electricity sector is a big case-in-point with the out-of-state offsets. And that continues to

enable the pollution of low income and communities of color. Another example is the price of the carbon, \$10 to \$13 a ton is absurdly low. Professor Drew Shindell documented the cost of CO2 at \$110 a ton. And I really appreciate Supervisor Serna's comment that that just doesn't force the way it's being done for all polluters to pay their costs. (RINCON-VITOVA2)

Comment:

The State's climate program should be just as transparent as other air pollution programs. This is necessary to retain public support and strengthen political will. There's a growing public perception that cap and trade is failing. The program doesn't incorporate the true cost of carbon pollution in credit purchases.

The availability of cheap out-of-state forest and other credits kicks the can down the road avoiding direct reductions from the industries most responsible for the climate crisis and air pollution. We know we need to end dependence on combustion for power. I've read comments by Chair Nichols saying exactly that.

Cap and trade delays sending the strong policy signal needed to move toward ending reliance a combustion. Plus, greenhouse gas reductions funded by cap and trade proceeds cost far more per ton than the original cost of the credits. California's Cap-and-Trade Program is not cost effective, in my opinion.

AB 197 sets a clear direction for the future of California's climate program to prioritize the social cost of carbon and direct emission reductions that will protect both the public health and the climate.

California's Cap-and-Trade Program should not be extended to 2030, because it is modeled on an outdated mindset that prioritizes industrial cost savings over public health -- removing public health burdens, and it's beset by too many other contentious problems.

It is not achieving the actual emission reductions from the largest sources. It allows greenhouse gas emissions increases in California. It's not cost effective, and it's harming public health in already burdened communities. (STROMBERG)

Comment:

California's Cap-and-Trade Program Adversely Affects Communities Facing Existing Pollution Burdens.

We share the serious concerns raised in the comments submitted by the Center on Race, Poverty and the Environment, et al., on the Proposed Amendments, regarding the ways in which cap-and-trade appears to be prolonging, and in some cases exacerbating, environmental burdens borne by low-income communities and people of color, and we include those comments by reference here.

According to the aforementioned report by Cushing, et al., which assessed the inequalities in the reductions of greenhouse gas emissions and associated particulate matter (PM₁₀) co-pollutants from sources covered under California's Cap-and-Trade program, "preliminary evidence suggests that in-state GHG emissions from regulated companies have increased on average for several industry sectors and that many emissions reductions associated with the program were linked to offset projects located outside of California."⁴⁹⁹ Cushing *et al.*, also found that "large GHG emitters that might be of most public health concern were the most likely to use offset projects to meet their obligations under the cap-and-trade program."⁵⁰⁰ Specifically, the report found that the first compliance period reporting data show that the cement, in-state electricity generation, oil and gas production or supplier, and hydrogen plant sectors have increased greenhouse gas emissions in the 2013-2014 compliance period over the baseline period (2011-2012). (CBD)

Response: Despite commenters' assertions to the contrary, the "Preliminary Environmental Equity Assessment" by Cushing et al. (Preliminary Assessment) does not demonstrate that the Cap-and-Trade Program disparately affects disadvantaged communities.

ARB strongly disagrees with commenters' contentions regarding the likelihood of localized emissions increases in criteria and toxic pollutants due to the implementation of the Cap-and-Trade Program. Indeed, the opposite effect is far more likely. As explained in greater detail in the Environmental Analysis, the proposed amendments primarily involve continuing the Cap-and-Trade Program after 2020. This, in turn, involves significantly more ambitious emissions reduction mandates, which are expected to produce dramatic reductions in GHG emissions and likely criteria pollutant⁵⁰¹ emissions across all sectors covered by the Cap-and-Trade Program.

Before considering how the commenters' contentions seek to rely on the Preliminary Assessment, it is important to consider the context under which the Preliminary Assessment was developed and the purposes for which it is designed. In the "Overview" section on page 1, the Preliminary Assessment disclaims that "[f]urther research is needed before firm policy conclusions can be drawn from this preliminary analysis." The Preliminary Assessment also notes that "[a]s regulated industries adapt to future reductions in the emissions cap, California is likely to see more reductions in localized GHG and co-pollutant emissions." (Preliminary Assessment at 10.)

⁴⁹⁹ Lara J. Cushing, Lara J. Cushing, Madeline Wander, Rachel Morello-Frosch, Manuel Pastor, Allen Zhu, and James Sadd, 2016, *A Preliminary Environmental Equity Assessment of California's Cap and Trade Program*, at 10. Available at http://dornsife.usc.edu/PERE/enviro_equity_CA_cap_trade.

⁵⁰⁰ *Id.* at 10.

⁵⁰¹ The "criteria pollutants" are ground-level ozone, carbon monoxide (CO), particulate matter (PM), lead, sulfur dioxide (SO_x), and nitrogen dioxide (NO_x).

Moreover, and contrary to several commenters' contentions, the Preliminary Assessment does not conclude that localized emissions in disadvantaged communities are increasing due to the Cap-and-Trade Program.

First, while noting some preliminary indications regarding increased emissions in certain industrial sectors and sources for the 2013-2014 period compared to the 2011-2012 period, the Preliminary Assessment does not account for several important macroeconomic and electricity sector causal factors that can help explain any increase in emissions. In this regard, commenters' contention that the Preliminary Assessment shows that the Cap-and-Trade Program exacerbates localized pollution burdens reflects a misconception: commenters assume that, because emissions may have increased at some sources after promulgation of the Cap-and-Trade Regulation, then the Cap-and-Trade Regulation must have caused such emissions increase. However, the sequence of these events does not indicate causality.

Most importantly, the economy was still significantly affected by the Great Recession in 2011-2012. Depressed demand for goods and services, as well as labor market slack, meant that production was lower in the 2011-2012 period compared to the 2013-2014 period, regardless of the Cap-and-Trade Program. As a result, to the extent emissions increased on both facility and sector levels over the entire 2011 to 2014 period, such emissions increases were likely due to production returning to pre-recession levels, not the Cap-and-Trade Program. Additionally, electricity sector emissions may have increased in 2013-2014, compared to 2011-2012, because of increased dispatch of natural gas-fired power plants due to (1) decreased hydroelectricity production as a result of California's historic drought, which started after 2011 and (2) the closure of the San Onofre Nuclear Generating Station (SONGS) in 2012. In addition, ARB staff notes that other commenters in this rulemaking have referenced these economic factors to help explain emissions changes in various sectors and, in fact, have presented documentation that "suggests that, if anything, GHG emissions declines have been slightly greater in [disadvantaged communities], though that the difference is not statistically significant."⁵⁰²

Second, the Preliminary Assessment is based on limited data. As recognized by the Office of Environmental Health and Hazard Assessment (OEHHA) in its February 2017 Initial Report on Tracking and Evaluation of Benefits and Impacts of Greenhouse Gas Limits in Disadvantaged Communities⁵⁰³ (referred to herein

⁵⁰² Maximilian Auffhammer, Severin Borenstein, James Bushnell, Meredith Fowlie, and Kyle Meng, Comments on the California Cap on Greenhouse Gas Emissions and Market Based Compliance Measures (August 2017), available at <https://www.arb.ca.gov/lists/com-attach/214-capandtrade16-BmdWlqNgUmlEbQVo.pdf> (citing to Kyle Meng, "Is cap-and-trade causing more greenhouse gas emissions in disadvantaged communities" (April 2017), available at https://www.dropbox.com/s/ka0a884oxkotxhj/Meng_CT_EJ.pdf?dl=1).

⁵⁰³ Available at <https://oehha.ca.gov/environmental-justice/report/ab32-benefits>.

as the “OEHHA Initial Report”) discussed further below, the emissions data available at this time do not allow for a conclusive analysis. The Cap-and-Trade Program is a relatively new program, with the first auction of emissions instruments occurring in 2012. In 2013-2014, the program covered large industrial sources and electricity generation. In 2015, the program expanded to cover emissions from combustion of gasoline and diesel, as well as natural gas use in commercial and residential applications. The OEHHA Initial Report also notes there are complexities in trying to correlate GHGs with criteria and toxics emissions across industry and within sectors, although preliminary data review shows there may be some poor to moderate correlations in specific instances. Further, OEHHA observed that “[t]he key challenge in analyzing the benefits and impacts of climate-change programs on disadvantaged communities is acquiring adequate data. As discussed in this report, data on emissions of GHGs, criteria air pollutants and toxic air pollutants are collected by multiple entities under different programs and statutory mandates. Differences in reporting requirements across regulatory programs can complicate data analysis. In addition, toxic emissions data for many facilities are only updated every four years, further limiting conclusions that can be reached.”⁵⁰⁴ Some specific challenges include matching facility identification numbers, coordinating data submittal requirements and methods, harmonizing reporting deadlines and frequency, and inconsistent quality assurance/quality control methods.⁵⁰⁵ In summary, sufficient data is not available yet to fully analyze the correlation between GHG and criteria emissions from these types of facilities. As discussed throughout this response, CARB is continuing to work on filling these data gaps to more accurately analyze this potential issue as new data becomes available. See below for more information on current efforts to gather the necessary data.

In summary, ARB staff continues to believe that localized air impacts from the Proposed Amendments are unlikely. Nevertheless, ARB has worked, and continues to work, to develop processes and mechanisms for protecting communities against localized emissions increases, regardless of their cause, as described in the sections below.

Role of local air quality regulation

In addressing the commenters’ concerns, it is also critical to understand how air pollution and climate regulation are implemented in California. The Cap-and-Trade Program is an economy-wide mechanism for limiting climate change causing pollutants. It is neither the intent nor the authority of the Cap-and-Trade

⁵⁰⁴ OEHHA, Initial Report: Tracking and Evaluation of Benefits and Impacts of Greenhouse Gas Limits in Disadvantaged Communities (February 2017) at 49.

⁵⁰⁵ ARB Staff Presentation: Informational Update on California’s Emission Inventories for Criteria Pollutants, Toxic Air Contaminants, and Greenhouse Gas Air Pollution, January 27, 2017. Available at <https://www.arb.ca.gov/board/books/2017/012717/17-1-3pres.pdf>.

Program to regulate criteria pollutant and toxic emissions from specific stationary sources, although program effects on these emissions were considered during the design of the Regulation.⁵⁰⁶ In general, ARB's statutory authority is limited to regulating mobile sources; ARB has direct authority to develop stationary source rules for GHG emissions, but it is not a permitting agency. ARB does not have the authority to permit local stationary sources nor directly regulate their emissions of toxic air contaminants and criteria air pollutants. The primary authority to regulate toxic air contaminants and criteria air pollutants at stationary source emissions, including the criteria pollutant and toxics emissions of concern to the commenters, is vested in the local air districts and U.S. EPA. (See Health & Safety Code § 39002.) The air districts and U.S. EPA have the power to require stationary sources to obtain air quality permits, and to establish the specific emissions limitations applicable to each facility.

ARB does consider matters of toxic risk through separate programs, and has endeavored to reduce toxic risk from industrial facilities throughout the State. As to criteria pollutants, ARB works with districts on air quality planning, and has approved district plans that will lead to attainment of state and federal air quality standards. As described elsewhere in this response, new legislation has also provided mechanisms for improving reporting, monitoring, and planning to address criteria pollutant and toxics emissions in high priority communities across the state.

In this context, Cap-and-Trade covered facilities of apparent interest to commenters have their construction, modification, and operation permitted by the air districts consistent with state and federal criteria and toxic pollution standards. These permit limits, which must also be consistent with attainment planning, are designed to ensure that sources cannot emit above levels protective of public health.

It is, thus, important to be aware that any emissions increases of concern to the commenters would need to be authorized under the permits issued by the local air districts. Otherwise, the facilities would be in violation of their permit requirements. ARB cannot permit higher emissions at any facility, and cannot cause emissions to exceed permit limits; nor does ARB revise these permits as a general matter to decrease emissions of toxics and criteria pollutants. As noted above, the air districts have primary permitting authority over these facilities. These levels are set after permit review, in accordance with district regulation

⁵⁰⁶ AB 32 requires ARB to satisfy several requirements in adopting regulations under AB 32, including ensuring that activities undertaken to comply with the regulations do not disproportionately impact low-income communities; ensuring that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions; and considering overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health. (See Health & Safety Code § 38562(b).)

and statute. Major stationary sources, of the sort covered by the Cap-and-Trade Regulation, generally must control permitted levels of criteria pollutant emissions consistent with at least the Best Available Control Technology (BACT), as defined in permitting regulations. This BACT analysis, and related analyses, are designed to ensure continued public health protection, and Cap-and-Trade cannot legally cause sources to exceed these limits. CEQA review also may pertain, and the air districts may require certain high priority facilities to prepare health risk assessments with respect to hazardous substances. If a health risk assessment indicates a significant risk associated with the facility's emissions, the facility must conduct an airborne toxic risk reduction audit and develop a plan to implement airborne toxic risk reduction measures that will result in the reduction of emissions from the facility to a level below the significant risk level within five years. Finally, recently enacted AB 617 (Chapter 136, Statutes of 2017) also requires districts, via a public process, to adopt an expedited schedule for implementing best available retrofit control technology (BARCT) for sources subject to the Cap-and-Trade Program by January 1, 2019, with implementation required by the earliest feasible date, but no later than December 31, 2023. This schedule will give the highest priority to those emission units that have not had the emissions-related conditions in their permits modified for the greatest period of time.

Efforts to evaluate and understand emissions impacts of Cap-and-Trade

As noted above, the Cap-and-Trade Program is a highly effective way to achieve economy-wide GHG reductions. The Cap-and-Trade Program is not a focused tool to reduce criteria pollutant and toxics emissions at specific facilities, nor was ARB authorized to require facility-specific criteria pollutant and toxic emissions reductions by AB 32. Criteria pollutant emissions, and many toxics emissions, are regulated at the local (air district) level. Nevertheless, ARB and other state agencies have undertaken substantial efforts to analyze the potential for adverse localized air quality impacts, which have informed ARB's proposed amendments. These efforts include:

- OEHHA analysis regarding potential localized impacts. In December 2015, the Governor issued a directive that OEHHA prepare a report analyzing the benefits and impacts of the GHG emissions limits adopted by ARB within disadvantaged communities, and directed OEHHA to continue updating that report every three years. In February 2017, OEHHA issued its Initial Report in response to this directive. This report concluded there are not enough emissions data available yet to allow for a comprehensive and conclusive analysis. (OEHHA Initial Report at 48.) However, OEHHA's preliminary findings confirm that a disproportionate number of large industrial facilities are located in or very close to disadvantaged communities, and it identified paths forward to acquire a range of data needed to identify and track any emissions increases that

could be attributable to the Cap-and-Trade Program. While the OEHHA Initial Report focused on the Cap-and-Trade Program, future reports will focus on the impacts of other climate programs on disadvantaged communities. (OEHHA Initial Report at 48-49.)

- ARB efforts to analyze criteria pollutants and toxic air contaminants with respect to greenhouse gas reduction measures. In 2011, as part of the original Cap-and-Trade Program rulemaking, ARB adopted an Adaptive Management Plan to help assess and address unlikely but potential localized air quality impacts resulting from the Cap-and-Trade Program. ARB has convened a Technical Workgroup consisting of industry, environmental justice, and academic representatives to evaluate the appropriate methodology to assess the impact of the Cap-and-Trade Program. CARB staff have also analyzed compliance period data from covered facilities and found similar data concerns to OEHHA. With the advent of Assembly Bill 197 (described more fully below), ARB will continue to assess greenhouse gas reduction measures, including the Cap-and-Trade Program, and any potential impact on criteria pollutants or toxic air contaminant emissions.

- In 2016, the California legislature passed Assembly Bill (AB) 197 (2016). This bill, passed in conjunction with Senate Bill (SB) 32, requires an array of changes, including (1) a requirement that ARB make available, and update at least annually, on its Internet Web site the emissions of greenhouse gases, criteria pollutants, and toxic air contaminants throughout the state broken down to a local and subcounty level for stationary sources and to at least a county level for mobile sources, and conduct monitoring in cooperation with other agencies to fulfill this requirement (Health & Safety Code § 39607) and a directive that ARB, when adopting rules and regulations to achieve greenhouse gas emissions reductions beyond the statewide greenhouse gas emissions limit, must follow the requirements of Health & Safety Code § 38562(b), consider the social costs of GHG emissions, and prioritize regulations that result in direct emission reductions at large stationary sources of GHG emissions, from mobile sources, and from other sources. (Health & Safety Code § 38562.5.)

In addition to the actions discussed above, other mechanisms are in place to address criteria pollutant and toxics emissions. These other actions will address both mobile and industrial sources, and will require coordination across multiple agencies:

- Achieve better integration of emissions and program data for GHGs, criteria pollutants, and toxics. ARB is working to enhance its CARB Pollution Mapping Tool to include toxics data, and to display multi-pollutant data for all sources at the county and sub-county level. ARB is also working to create an integrated inventory database system, and is

investigating ways to harmonize the timing of data submittals and make data methodologies for criteria and toxic pollutants more consistent.⁵⁰⁷

- Continued analysis by OEHHA. Pursuant to the Governor's directive, OEHHA will continue to analyze the benefits and impacts of the GHG emissions limits adopted by ARB within disadvantaged communities with respect to programs adopted pursuant to AB 32. This analysis will include potential benefits and impacts in disadvantaged communities for other AB 32 programs outside of the Cap-and-Trade Program.
- ARB recently adopted the State SIP Strategy, which lists a suite of measures ARB has committed to develop in the coming years. ARB's Mobile Source Strategy and Sustainable Freight Strategy give further information and context regarding ARB's proposed upcoming statewide measures to transform the mobile source and freight sectors.

Finally, newly-enacted AB 617 directs and authorizes ARB to take several actions to improve data reporting and monitoring, and institute pollution reduction plans for specific communities across the state. With regard to reporting, AB 617 requires ARB to develop a uniform statewide annual reporting system of criteria pollutants and toxic air contaminants for certain categories of stationary sources. As for monitoring, it requires ARB to prepare a monitoring plan for criteria and toxic pollutants by October 1, 2018. Via a public process, this plan would identify the highest priority locations—based on an assessment of the locations of sensitive receptors and disadvantaged communities—around the state to deploy community air monitoring systems. By July 1, 2019, any district containing a high priority location would need to deploy a community air monitoring system for that location or locations. The districts also have authority to require nearby facilities to deploy a fenceline monitoring system under certain conditions. These efforts will help ARB better understand the complex emissions interrelations between the Cap-and-Trade Program and air district criteria and toxics programs.

Finally, with regard to planning, AB 617 also requires ARB to prepare, in consultation with numerous stakeholders (including environmental justice organizations), a statewide strategy to reduce emissions of toxic air contaminants and criteria air pollutants in communities affected by a high cumulative exposure burden by October 1, 2018. Based on the strategy, ARB selects locations around the state for preparation of community emissions reduction programs. In turn, the air districts must adopt the community emissions reduction programs, which must include emissions reduction targets, specific reduction measures, a schedule for implementation, and an enforcement plan.

⁵⁰⁷ See ARB Staff Presentation: Informational Update on California's Emission Inventories for Criteria Pollutants, Toxic Air Contaminants, and Greenhouse Gas Air Pollution, January 27, 2017. Available at <https://www.arb.ca.gov/board/books/2017/012717/17-1-3pres.pdf>.

Efforts to reduce criteria pollutant and toxics emissions

As noted previously, commenters' concern regarding criteria and toxic emissions have more to do with traditional air pollution regulation than ARB's climate programs. As discussed above, local air districts, rather than ARB, have direct authority to regulate criteria pollutant and toxic emissions from stationary sources. Nevertheless, for many decades, the State has implemented many policies and programs to address and reduce criteria and toxic air pollutants. As a result of these efforts, significant progress has been made in reducing diesel particulate matter (PM) and many other hazardous air pollutants. For example, and based on the most current CEPAM inventory (2016 SIP inventory tool V. 1.05), statewide NO_x emissions have been reduced by 26 percent between 2012 and 2017, and diesel PM has been reduced by 50 percent over the same period.

ARB partners with air districts to address stationary emissions sources and adopts and implements State-level regulations to address sources of criteria and toxic air pollution, including mobile sources. The key air quality strategies being implemented by ARB include:

- **State Implementation Plans.** As referenced in the ISOR, the 2016 State Strategy for the State Implementation Plan sets forth a comprehensive array of proposed control measures designed to achieve the emission reductions from mobile sources, fuels, stationary sources, and consumer products necessary to meet ozone and fine PM attainment deadlines established by the Clean Air Act.
- **Diesel Risk Reduction Plan.** As referenced in the 2010 ISOR to the Cap-and-Trade Regulation and the functional equivalent document incorporated by reference in the EA, California's Diesel Risk Reduction Plan recommends many control measures to reduce the risks associated with diesel PM and achieve a goal of 85 percent PM reduction by 2020. Diesel PM accounts for the majority of California's ambient air cancer risk.
- **Sustainable Freight Action Plan.** As referenced in the EA, Executive Order B-32-15 required the development of an integrated Sustainable Freight Action Plan, which seeks to improve freight efficiency, transition to zero emission technologies, and increase competitiveness of California's freight system. This Action Plan was released in July 2016.
- **AB 32 Scoping Plan.** As referenced in the ISOR and in the EA, the original (2008), first update (2014), and ongoing 2017 Scoping Plan Update contain the main proposed strategies California will use to reduce the GHGs that cause climate change and achieve the State's climate goals. Following new legislative direction in AB 197 (discussed above), the 2017 Scoping Plan Update currently under development estimates the toxic and criteria emissions reductions co-benefits expected of proposed scoping plan measures.
- **AB 1807.** As referenced in the EA, AB 1807 requires ARB to use certain criteria in prioritizing the identification and control of air toxics.

- **AB 2588 Air Toxics “Hot Spots” Program.** As referenced in the EA, AB 2588 imposes air quality requirements on the state. The goals of the program are to collect emission data, identify facilities having localized impacts, ascertain health risks, notify nearby residents of significant risks, and to reduce those significant risks to acceptable levels. To support efforts to advance the State’s toxics program, OEHHA finalized a new health risk assessment methodology on March 6, 2015. In light of this, ARB is collaborating with air districts in the review of the existing toxics program under AB 2588 to strengthen the program.
- **SB 605 Short-Lived Climate Pollutant Plan.** In March 2017, ARB adopted a comprehensive short-lived climate pollutant strategy, which involves coordination with other state agencies and local air quality management and air pollution control districts to reduce emissions of short-lived climate pollutants. This strategy offers many localized air quality benefits, including reductions in volatile organic compound (VOC) emissions from oil and gas operations and livestock operations, as well as particulate matter reductions from incentives to replace woodstoves.

Responses to commenters’ other concerns regarding potential impacts to disadvantaged communities

The commenters state that there are foregone benefits in reducing criteria and toxics air pollutants by deploying the Cap-and-Trade Program. As noted above, the Cap-and-Trade Program is designed to primarily address GHGs, not criteria and toxics air pollutants. However, to the extent actions are taken to improve onsite efficiency and reduce the combustion of fossil fuels, the Cap-and-Trade Program will likely drive GHG as well as criteria and toxic emission reductions co-benefits. The Preliminary Assessment discussed above and cited by the commenters states, “As regulated industries adapt to future reductions in the emissions cap, California is likely to see more reductions in localized GHG and co-pollutant emissions.” Indeed, the post-2020 framework for annual emissions caps requires deeper annual emissions reductions than what the Cap-and-Trade Program requires leading up to and including 2020.

At the same time, there are only three years of data available for the Cap-and-Trade Program. Again, the authors for the Preliminary Assessment state, “Further research is needed before firm policy conclusions can be drawn from this preliminary analysis.” It is premature to draw conclusions that there are, or will be, no co-benefits associated with the Cap-and-Trade Program at this time, as more data is needed to inform this type of analysis. To ensure transparency in how emissions are changing among covered entities, ARB makes available annually reported and verified GHG emissions data, issuance data for offsets that includes location and offset type, and how entities comply with the program with allowances and the use of offsets. This data will continue to be made

publicly available as the program continues, fostering more informed analysis regarding emissions changes at both facility and regional levels.

A commenter also claims GHG emissions in certain sectors have increased from a “baseline period.” It is unclear what “baseline” the commenter references. The Cap-and-Trade Program tracks progress relative to the statewide target rather than against a baseline period. In general, GHG emissions declined sharply during the Great Recession and slowly increased as the economy grew over the years immediately following the recession. It is important to note that the GHG emissions per capita and per dollar of Gross Domestic Product have declined over this same period of time—meaning the State’s economy is decarbonizing. Therefore, any GHG emissions increases at either the facility or sector-wide level have resulted from the economic recovery rather than from the Cap-and-Trade Program. Moreover, as indicated in the annually reported and verified GHG emissions data, GHG emissions have been declining statewide since the adoption of the Cap-and-Trade Program.⁵⁰⁸

The commenters claim that emissions reductions under the program are mostly from out-of-state offsets. The ARB GHG Inventory, which is the critical tool used to track reductions that meet the statewide GHG target, includes in-state smokestack, tailpipe, and emissions associated with imported power to serve California load. Use of out-of-state offsets in the Cap-and-Trade Program is not used to track the State’s progress towards achieving its statewide GHG target. When comparing the actual GHG emissions that are covered under the program, without any adjustments for offsets, covered entity emissions are under the caps in the program. And, as the Cap-and-Trade Program covers 85 percent of the GHG emissions in the State and given that the caps decline annually, there will be direct emissions reductions from those sources. These covered sources include large stationary facilities (manufacturing, refineries, power plants, and cement plants), mobile sources, and emissions associated with imported electricity to serve California load. See also response to 45-day comments K-1.2. Additionally, recently enacted AB 398 is pertinent to the concerns raised by commenters. AB 398 would require ARB to develop regulations reducing the quantitative usage limit for offsets, and would require one half of offsets within that limit to provide direct environmental benefits in the state, from the period of January 1, 2021 to December 31, 2030. AB 398 would also establish a Compliance Offsets Protocol Task Force to provide guidance to ARB in approving new offset protocols for the purpose of increasing offset projects with direct environmental benefits in the state while prioritizing disadvantaged communities, Native American or tribal lands, and rural and agricultural regions.

⁵⁰⁸ See California Air Resources Board Web page, Mandatory GHG Reporting – Reported Emissions, <https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm>.

The commenters also assert that offsets are “questionable” and cannot accomplish the objective of being permanent and real. Under AB 32, all offsets utilized as part of the Cap-and-Trade Program must be real, additional, permanent, verifiable, quantifiable, and enforceable. ARB has developed rigorous offset quantification methods that incorporate the AB 32 criteria and ensure any offset issued and used in the Program meets these criteria. ARB’s method of implementing the statute with respect to offsets was upheld by the First District Court of Appeals in *Our Children’s Earth Foundation v. ARB* (2015) 234 Cal. App. 4th 870.

With respect to the portion of the comments expressing concerns with the level of accessibility of Cap-and-Trade and GHG emissions data, ARB staff notes that annual facility-level GHG data, entity-level compliance status, and instrument usage (e.g., number of each vintage of allowances and the number of offsets and specific projects) is published each year. Some data collected by ARB pursuant to MRR and the Cap-and-Trade Regulation constitutes legally protected trade secrets (i.e., confidential business information), the release of which would not be legally permitted. ARB staff’s presentation at the September 22, 2016 Board hearing included a description of the important transparency that exists for this Program. See also response to 45-day comments K-1.3.

K-1.6. Comment:

As mentioned in the Initial Statement of Reasons (“ISOR”), the Air Resources Board has yet to finalize and/or implement the Adaptive Management Plan that has been under development since 2011, and which may be able to identify potential public health issues such as those identified in Cushing *et al.*, ISOR at 302. Furthermore, the long-awaited Adaptive Management Plan, as it has so far been represented, is narrowly constrained to look only at *increases* in emissions due to the implementation of California’s Cap-and-Trade program and is deliberately designed *not* to identify scenarios in which California’s Cap-and-Trade program results in the persistence of emissions or slower reductions in some communities and locations compared to others. These are serious problems that call for rejecting the Proposed Amendments to extend California’s Cap-and-Trade program beyond 2020, and a [sic] (CBD)

Response: The commenter argues that the lack of a finalized Adaptive Management Plan, and specifically one which purports to go further than ARB’s efforts, is reason enough to reject the proposed amendments. The more stringent GHG cap post-2020 means that GHG emissions will be reduced to an even greater extent for the 2021-2030 period than for the 2012-2020 period. These GHG emissions reductions will likely result in criteria and toxic air pollutant emissions reductions as well. Additionally, California’s air pollution control programs for criteria and toxic pollutants will continue to significantly reduce emissions and health risk into the future. Based on the available data, current law and policies that control localized air pollution, and expected compliance

responses to the Cap-and-Trade Regulation, ARB staff continues to believe that any increases in localized air pollution, including toxic air contaminants and criteria air pollutants, attributable to the Program are highly unlikely. Regardless, ARB's existing process in implementing its regulations is to review and adjust programs as warranted. As part of this process, ARB has convened a technical workgroup consisting of industry, environmental justice advocates, and academics to evaluate the appropriate methodology to assess the impact of the Cap-and-Trade Program. ARB staff have analyzed criterial pollutant data from covered facilities and found similar data concerns to OEHHA. Please also refer to response to 45-day comment K-1.5 for more detail. For the reasons indicated in the ISOR and the responses contained in this FSOR, ARB staff declines to make the change requested by the commenter; namely, to not move forward with these amendments.

K-1.7. Comment:

ARB staff must fully consider all scenarios in the 2030 Target Scoping Plan. The 2030 Target Scoping Plan has four scenarios, only one of which focuses on Cap and Trade. All of these scenarios need to be fully analyzed and considered by ARB.

For these reasons, we respectfully request that ARB reject the staff's recommendation to continue the cap-and-trade program post-2020. (CEJA)

Response: This comment appears to have been made in the ongoing 2017 Scoping Plan Update process. To the extent it offers a specific comment on these amendments, ARB staff notes that the Scoping Plan Update presents a Proposed Scoping Plan Scenario and four alternatives to achieve the GHG emissions reductions required by 2030. The Scoping Plan Update itself considers and analyzes these scenarios and recommends the Proposed Scenario, which includes extending the Cap-and-Trade Program to ensure the State's 2030 emissions reduction target is achieved. Additionally, pursuant to Government Code section 11346.2, ARB considered and evaluated reasonable alternatives to the Proposed Amendments in the ISOR and provided reasons for rejecting those alternatives. ARB has satisfied its obligation to analyze alternative scenarios to extending the Cap-and-Trade Program. As such, ARB staff declines the commenters' request to reject the proposed amendments.

K-1.8. Multiple Comments:

Nevertheless, we write here to raise concerns with respect to ARB's legal authority to extend the cap-and-trade program after its current expiration at the end of 2020. In a separate comment letter we also address substantive policy and market design considerations in ARB's proposal.

We believe that the risk of proceeding with the proposed rule is significant. The lack of clear legal authority to continue cap-and-trade after 2020 will bring a high profile legal

challenge from industry opponents. And in contrast to the current challenge to allowance auctions in the cap-and-trade program, we believe that the risks of a defeat for ARB are much greater. Any such litigation, if successful, would do serious damage to California's leadership on climate policy.

We also believe—based upon discussions with market participants and our observation of recent market activity in secondary spot, futures, and options markets—that the passage of SB 32 has not convinced market participants that ARB has legal authority to implement cap-and-trade after 2020. Market sentiment is an important objective because this proceeding is designed in part to increase interest, and hence demand, at ARB administered allowance auctions from now until 2020.⁵⁰⁹ Proceeding with this rulemaking is unlikely to restore market confidence; losing a lawsuit concerning ARB's authority to proceed with cap-and-trade in the post 2020 period could do much to damage it.

We are also concerned that the timing of this rulemaking appears to have been driven by a need to finalize rules in order to schedule and hold auctions of post-2020 future vintage allowances according to currently established timelines and procedures. While the stable and predictable administration of the market is a valid concern, we urge the board to weigh a minor procedural deviation against the risk of a potentially successful challenge of authority to implement the post-2020 program at all.

Meanwhile, the Legislature and Governor's office have publicly indicated their intention to revisit the question of post-2020 climate policy and carbon pricing in the upcoming 2017 legislative session. Given these commitments, we urge the Board to weigh the serious risks of proceeding with its proposed regulation against the relatively modest costs of waiting for the Legislature to act next year.

In our judgment, the risks are so significant that the Board should withdraw or delay finalizing the proposed regulation until such time as the Legislature provides clear and specific authority to extend the cap-and-trade or utilize another carbon pricing mechanism in the post-2020 period. If the Board opts instead to proceed with the present rulemaking, it should state clearly and forthrightly why it has legal authority to extend the cap-and-trade program beyond 2020 given Cal. Health and Safety Code Section 38652(c) and Proposition 26. To be clear, we want very much to be convinced by the arguments ARB presents on these issues. But we also believe that the interests of the Board and of the State of California are not well served by failure to address them in the ISOR. We respectfully detail our concerns in greater detail below.

⁵⁰⁹ Id. at 16-17 (discussing ARB's proposal to transfer unsold allowances into the Allowance Price Containment Reserve, where the allowances would be made available at \$60 per tCO₂e above the price floor in the post-2020 program). We discuss this issue in detail in Section 3 of our policy comment letter in this docket.

1. CARB should explain its statutory authority under AB 32, as amended, to extend the cap-and-trade program beyond 2020.

Under currently applicable regulations, the cap-and-trade program is authorized only through the end of 2020.⁵¹⁰ We note that the market's enabling statute, AB 32, authorizes ARB to develop market-based measures (including cap-and-trade) in order to reduce statewide emissions to their 1990 levels by 2020. However, Section 38562(c)—the provision of AB 32 under which ARB developed and maintains California's cap-and trade market—is time-limited:

In furtherance of achieving the statewide greenhouse gas emissions limit, by January 1, 2011, the state board may adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020, inclusive, that the state board determines will achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions, in the aggregate, from those sources or categories of sources.⁵¹¹ [Emphasis added.]

The relationship between ARB's authority to maintain a post-2020 cap-and-trade program and this statutory provision is particularly important for ARB to clarify because the standard judicial interpretation of a time limited grant of authority is to foreclose the use of that authority after the stated period of time. Thus, a reviewing court would likely presume that the Legislature meant to grant ARB authority to employ a cap-and-trade program through the end of 2020, but not after 2020.

Such an interpretation is all the more likely because other provisions in AB 32 grant authority to ARB in perpetuity. For example, AB 32 provides the authority to maintain statewide emissions at no more than the 2020 statewide target level after 2020.⁵¹² When a time-limited grant of authority is found alongside a perpetual grant of authority, a reviewing court is even more likely to conclude that the time-limited grant of authority forecloses use of that authority beyond the stated period of time because other provisions in the same statute illustrate that the Legislature intended to distinguish between applicable time horizons. As a result, the broader context of AB 32 makes it even more likely that a reviewing court would interpret Section 38562(c) as foreclosing the authority to continue cap-and-trade after 2020.

If ARB believes Section 38562(c) is ambiguous and should not be interpreted to foreclose the use of cap-and-trade after 2020, the Board has an obligation to explain its reasoning in the proposal. Yet nowhere in its proposed regulation does ARB clearly state that it believes it has the necessary statutory authority to continue cap-and-trade

⁵¹⁰ Cal. Code Regs. tit. 17, §§ 95840-41.

⁵¹¹ Cal. Health & Safety Code § 38562(c).

⁵¹² Id. at 38551(a) ("The statewide greenhouse gas emissions limit shall remain in effect unless otherwise amended or repealed.")

beyond the program's current expiration at the end of 2020; indeed, the proposal does not mention the time-limited authority issue or refer to Section 38562(c) as even a potential barrier to the legal authority it claims.

Instead, the proposal makes two references to authority to “maintain and continue” emission reductions beyond 2020⁵¹³ and to comply with the Governor’s executive order targets for 2030 and 2050, consistent with existing (but unspecified) statutory authority.⁵¹⁴ We presume this “maintain and continue” phrase refers to Section 38551 of AB 32:

(a) The [2020] statewide greenhouse gas emissions limit shall remain in effect unless otherwise amended or repealed.

(b) It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020. [Emphasis added.]

(c) The state board shall make recommendations to the Governor and the Legislature on how to continue reductions of greenhouse gas emissions beyond 2020.⁵¹⁵

As an initial matter, we note that the “maintain and continue” phrasing occurs in an aspirational clause—in subsection (b), the Legislature is declaring its intent, not requiring or explicitly authorizing ARB to achieve deeper targets. Similarly, subsection (c) declares that ARB “shall make recommendations” on how to achieve deeper post-2020 greenhouse gas reductions. Thus, in our view, the plain text of subsections (b) and (c) does not provide a firm basis for ARB to develop post-2020 policies. At a minimum, ARB needs to explain how it interprets these provisions.

In addition, subsection (a) clearly requires that the legally binding 2020 statewide greenhouse gas emissions limit⁵¹⁶ will continue to apply after 2020; thus, the aspirational language of subsection (b) and the advisory nature of subsection (c) indicate that the Legislature intended to differentiate between the requirements of each subsection.

Even if Section 38551(b)’s “maintain and continue” language is strictly binding, and not merely aspirational, it has at best unclear relevance to addressing the apparent time-limited grant of authority to employ cap-and-trade after 2020. It would be entirely logical for a court to interpret AB 32 such that (1) authority to use cap-and-trade would expire in 2020 (per Section 38562(c)), even as (2) the 2020 statewide target continues to apply in 2021 and thereafter (per Section 38551(a)) and (3) ARB has the authority to maintain and continue deeper post-2020 statewide emission reductions (per a robust

⁵¹³ ISOR at ES-1; id. at 1.

⁵¹⁴ Id. at 3.

⁵¹⁵ Cal. Health & Safety Code § 38551.

⁵¹⁶ Id. at § 38550 (requiring that “the state board shall ... determine what the statewide greenhouse gas emissions level was in 1990, and approve ... a statewide greenhouse gas emissions limit that is equivalent to that level, to be achieved by 2020.”).

interpretation of Section 38551(b)). Thus, not even a generous interpretation of Section 38551(b) resolves the time-limited grant of authority in Section 38562(c).

Section 38551 is even less relevant in light of positive developments in the state climate policy that have transpired since ARB issued this regulatory proposal. At the very end of the 2016 session, the Legislature passed SB 32, which the Governor then signed into law.⁵¹⁷ SB 32 is a remarkable accomplishment for climate policy because it codifies the Governor's ambitious objective for 2030—reducing statewide greenhouse gas emissions 40% below their 1990 levels.⁵¹⁸

We applaud this outcome but note that SB 32's success frustrates any legal argument that Section 38551 can be used to justify post-2020 authority to employ cap-and-trade. Any argument that Section 38551 authorizes post 2020 statewide emission reductions is now irrelevant in practical terms because SB 32 provides the necessary authority to reach the 2030 statewide emissions target. In turn, the 2030 target implies a consistent trajectory from the relatively less stringent 2020 target towards the more stringent 2030 target.

Furthermore, the legislature's decision in SB 32 not to amend Section 38562(c)'s time limited grant of authority, despite apparent attempts by the Governor to include such language in the bill, might be viewed as significant by a court reviewing the ISOR.

Finally, we note that the more general language at Section 38562(b) requiring ARB to consider the cost-effectiveness of the regulations it adopts to limit greenhouse gases, to consider the overall societal benefits of the program, and to minimize administrative burdens, do not, without a well developed legal theory, allow for the extension of cap-and-trade either. These general provisions would not usually override a more specific, time-limited grant of authority, such as that in Section 38562(c). If ARB believes that they do, it should explain its reasoning.

As a result of the specific time-limited grant of authority to employ cap-and-trade in Section 38562(c) and the general irrelevance of authority to "maintain and continue" emission reductions in light of SB 32, ARB needs to clearly and forthrightly explain its view of the statutory authority to employ cap-and-trade after 2020.

2. CARB should explain why extension of the cap-and-trade under SB 32 does not trigger the provisions of Proposition 26.

SB 32 is a laudable milestone in climate policy. Nevertheless, it does not create clear authority for ARB to continue auctions of government-owned allowances in a cap-and-trade program after 2020 because of the provisions of Proposition 26, which are codified in the California Constitution. Because we believe that auctions of government-owned allowances are a critical component of the current cap-and-trade market

⁵¹⁷ SB 32 (Pavley), Global Warming Solutions Act of 2006: emissions limit, https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32

⁵¹⁸ Cal. Health & Safety Code § 38556 (as added by SB 32).

design—and that without them and the Greenhouse Gas Reduction Fund, there might not be sufficient political support for this approach to achieving SB 32’s goals—we respectfully request that ARB address the applicability of Proposition 26 to its regulation.

Pursuant to Proposition 26, “any change in statute” that raises any taxpayer’s taxes must pass both houses of the legislature by a 2/3 supermajority vote.⁵¹⁹ In turn, Proposition 26 defines “tax” as “any levy, charge, or exaction of any kind imposed by the State.”⁵²⁰ Under this expansive definition, the cap-and-trade program’s auction of government owned allowances almost certainly constitutes a tax for the purposes of Proposition 26 because covered parties that need to obtain these allowances would characterize them as a “levy, charge, or exaction ... imposed by the State.”

It would seem that SB 32 cannot be used to justify extending ARB’s authority to employ allowance auctions after 2020 because SB 32 passed by a simple legislative majority. The reasoning is simple. If SB 32 creates new authority that was not otherwise present in AB 32, it is a change in statute. Any change in statute that causes any taxpayer to pay a higher tax requires a 2/3 supermajority vote.⁵²¹ Because extending the cap-and-trade program while retaining the auction of government-owned allowances appears to constitute a tax for the purposes of Proposition 26,⁵²² SB 32 would have required a 2/3 supermajority vote in order to extend the cap-and-trade program.

If this argument is wrong, ARB needs to explain why. The Proposition 26 issue is well known in policy and legal circles, and therefore the absence of a comprehensive discussion in the current rulemaking lowers, rather than increases, market confidence in the program.

Because SB 32 passed by a simple majority vote it most likely cannot be used to justify an extension of ARB’s authority to employ cap-and-trade after 2020. Any such authority must be found in the pre-Proposition 26 statutory authority contained in AB 32, or in subsequent statutory changes that are consistent with Proposition 26. We again respectfully request that ARB either articulate a legal justification that addresses these issues or consider withdrawing or suspending the current proposal until future action on the part of the Legislature and Governor clarifies the situation.

⁵¹⁹ California Constitution, Art. XIII A § 3(a)

⁵²⁰ *Id.* at § 3(b).

⁵²¹ *Id.* at § 3(a).

⁵²² We note that this is a separate question from whether the current cap-and-trade program is a “tax” under Proposition 13, e.g. as raised in the ongoing *Morning Star Packing Company / California Chamber of Commerce* litigation. California case law recognizes permissive categories of policies that are not considered taxes for the purposes of Proposition 13, which never defined the key term “tax.” These kinds of judicial exemptions are not available for statutory changes made after 2010, after which point Proposition 26 and its expansive definition of “tax” apply.

We believe there is time to work these issues out. In contrast, finalizing a regulation before their resolution would be extremely unhelpful to achievement of the cap-and-trade's ultimate objectives.

3. CARB has not identified a firm basis in state law for pursuing a state measures approach to Clean Power Plan compliance.

Finally, we note that ARB has proposed using a post-2020 extension of the cap-and-trade program as a means of complying with the U.S. Environmental Protection Agency's Clean Power Plan via a "state measures" approach.⁵²³

Under the federal Clean Power Plan,⁵²⁴ states may choose to develop compliance plans based on so-called state measures that require comparable or greater emission reductions at affected Electricity Generating Units than the mass-based target calculated by EPA.⁵²⁵ Among other requirements, states pursuing this compliance option must identify the specific laws and/or regulations (i.e., the state measures) that achieve the emission reductions EPA requires.⁵²⁶ In turn, each state measure must be "quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity."⁵²⁷

Absent a clear explanation of ARB's authority to extend its cap-and-trade program beyond 2020, we do not see how ARB can satisfy EPA's requirements for a state measures plan.

California is already doing a great deal to reduce greenhouse gas emissions from the power sector—including its bold 50% renewable portfolio standard, to be achieved by 2030⁵²⁸—so we are optimistic that the substantive efforts required for Clean Power Plan compliance are well underway. Nevertheless, presenting EPA with a state measures plan that relies on regulations that face significant litigation risks raises the prospect of damaging both California's and EPA's credibility at a time when the Clean Power Plan is very much under attack. Particularly given the lack of any currently applicable requirement that ARB submit a state measures plan to EPA until completion of the pending litigation, there are good reasons to continue planning but to delay formalizing a plan at this time—both for EPA's sake and for California's. Again, we would be happy to be proven wrong here, but the absence of any argument in the ISOR

⁵²³ ISOR at 22-29; accord California Air Resources Board, California's Proposed Compliance Plan for the Clean Power Plan Under Clean Air Act Section 111(d) (Aug. 5, 2016) at 1-2, available at <https://www.arb.ca.gov/cc/powerplants/powerplants.htm>.

⁵²⁴ U.S. Environmental Protection Agency, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015).

⁵²⁵ Id. at 64,668 (describing the state measures option).

⁵²⁶ Id. at 64,945 (to be codified at 40 C.F.R. § 60.5745(a)(6)(i)).

⁵²⁷ Id. at 64,948 (to be codified at 40 C.F.R. § 60.5780(a)).

⁵²⁸ Cal. Public Utilities Code § 399.11(a).

concerning either the statutory or constitutional provisions that might limit ARB's authority to act leaves us concerned.

We urge ARB to proceed with caution and note that several alternatives are available. ARB could, for example, wait to develop a formal compliance strategy until it has clear legislative authority to extend cap-and-trade;⁵²⁹ identify other state measures (such as SB 350) that would be sufficient to meet its Clean Power Plan target; or adopt one of the standard rate- or mass-based targets offered by EPA. Simply put, there is no need to rush—and certainly not on anything less than solid legal footing.

4. Unless ARB can articulate a clear and compelling legal basis for extending cap-and-trade beyond 2020, it should withdraw or suspend the proposed regulation and urge the Legislature to act.

We strongly support California's climate policy leadership and have great respect for the efforts that the Board, ARB Staff, the Legislature, and two successive Governors have brought to bear on this important issue over the past fifteen years. We also believe that market-based climate policies, such as cap-and-trade, will be critical to achieving the deeper emission reductions required for long-term climate mitigation, including SB 32's target for 2030 as well as the target for 2050 contained in executive orders from Governors Brown and Schwarzenegger.

Nevertheless, we are concerned that ARB's proposal does not provide a clear and compelling legal basis for extending the cap-and-trade program beyond 2020. That the proposal does not address apparent limitations in the cap-and-trade program's original authorizing provision nor the limitations created by recent changes to the California Constitution is especially troubling. We respectfully request that ARB either address these issues in a transparent and rigorous manner, or withdraw or suspend the proposed rule with a clear request that the Legislature and Governor provide the necessary authority to act. (CULLENWARD)

Comment:

ARB is on questionable legal ground by generating auction revenue from an effective tax on carbon absent the necessary legislative vote. We ask the Board to be cognizant of the outstanding legislative and legal issues that could affect the outcome of the current program. (CCPC)

⁵²⁹ The final Clean Power Plan contains an initial deadline for state plan submissions of September 6, 2016. EPA, 80 Fed. Reg. at 64,946 (to be codified at 40 C.F.R. § 60.5760(a)). In addition, states can petition for up to a two-year extension for state plan submissions. *Id.* at 64,947 (to be codified at 40 C.F.R. § 60.5760(b)). In February 2016, however, the Supreme Court stayed implementation of the Clean Power Plan pending the final outcome of litigation, effectively suspending the compliance timeline. *West Virginia v. EPA*, 136 S. Ct. 1000 (2016). We believe it is extremely likely that EPA will extend state plan submission deadlines if it is successful in court. As a result, ARB need feel no pressure to prepare the first state plan.

Comment:

I know you don't want to talk about this point. But it's the fact that this Board does not have the legal authority to proceed with a cap and trade extension after 2020. During the AB 32 process, a section was inserted into the bill, section 38562 subsection (c), of the Health and Safety Code that limited the Board's authority during a specific time period to implement cap and trade. And that time period ends in 2020. That provision hasn't been amended. The Governor has tried twice, once in 2015 and again in 2016 to get that provision changed. Senate Bill 32 and Assembly Bill 197 did not change that either. This Board does not have the authority to do this rule-making. That's the plain and simple fact. And I know you don't want to talk about it, but it's the truth. (CENTRACEPOENV)

Comment:Post-2020 Authority Questions Remain

The proposed amendments ignore a limitation in current statute by failing to address the fact that the original California Global Warming Solutions Act of 2006 (AB 32) only authorized ARB to operate a market-based mechanism through 2020 and not beyond. The implication of the explicit authorization in AB 32 is that ARB does not otherwise have such authority. Based on ARB's work on the Scoping Plan to date, this leaves very costly options for the Board pursue absent subsequent legislative action that would result in significant problems for California's economy. Therefore, CMTA believes that ARB should pause development of post-2020 cap and trade amendments until future legislation can secure the authority to ARB.

CMTA Comments on California Cap on Greenhouse Gas Emission and Market-based Compliance Mechanisms Regulation (CMTA)

Comment:

The plan for clean energy says that the State's says the states may only approve programs that have been authorized for them, but ARB does not have the authority to extend it for beyond 2020, especially after the law that opposed it during these two years. (MARQUEZ)

Comment:The State Board has no Authority to Extend Cap and Trade after 2020.

The State Board lacks authority to act on these proposed regulations. Staff propose amendments to various provisions of the Cap and Trade regulations to extend the program beyond the year 2020. See, e.g. ISOR at 149 (describing changes to section 95841 to establish allowance budgets for the years 2021 to 2050); ISOR at 299 (describing Appendix C to set dates for auctions and reporting for the years 2021 to 2050). A fundamental principle of administrative law dictates that agencies only have those powers delegated by the Legislature. The State Board's authority to implement

the Cap and Trade program expires on December 31, 2020 and the Board has no authority to adopt regulations to extend the program beyond that date. Health & Safety Code §§ 38562(c), 38570.

ARB staff have claimed that AB 32 authorizes these regulations because of language in Part 3 of AB 32 related to the statewide greenhouse gas limit (the level of emissions in 1990). “It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020.” Health & Safety Code § 38551(b). Grasping on to the words “continue reductions,” the staff believe they can extend Cap and Trade to 2030 and then all the way to 2050. This provision, however, must be understood in the context of the statutory scheme as a whole. The very next subsection of section 38551 directs the State Board to make recommendations to the Governor and the Legislature on how to continue reductions, and does not give the State Board the authority to take those actions *sua sponte*. “The state board shall make recommendations to the Governor and the Legislature on *how* to continue reductions of greenhouse gas emissions beyond 2020.” Health & Safety Code § 38551(c) (emphasis added).

Nor has the Legislature acted to extend the State Board’s authority. During the 2015 legislative session, the version of Assembly Bill 1288 (Atkins) containing an extension of the State Board’s authority to implement Cap and Trade beyond December 31, 2020 did not become law. During the 2016 legislative session, Senate Bill 32 became law and requires the State Board to achieve a 40 percent reduction in greenhouse gas emissions below 1990 levels by 2030. Stats. 2016, ch. 249, § 2, p. 88 (codified as Health & Safety Code § 38566). No provision of Senate Bill 32 amended section 38562(c) or otherwise authorized the State Board to implement Cap and Trade after the year 2020. Accordingly, the State Board lacks the authority to adopt the Proposed Amendments and should not proceed absent direction from the Legislature. (JOINTENVJUSTICE)

Response: The commenters express concerns regarding ARB’s legal authority to extend the current Cap-and-Trade Program beyond 2020. The comments do not make specific requests for changes, unless it would be to cease moving forward with this rulemaking. Contrary to these commenters’ views, ARB has legal and constitutional authority to adopt the Proposed Amendments.

The role of ARB is that it is the state agency charged with regulating sources of GHG emissions in order to reduce GHG emissions. Health & Safety Code § 38510. ARB’s role is not extinguished in 2020. Indeed, the Legislature intended, in enacting AB 32, that ARB continue GHG emissions reductions beyond 2020. *Id.* § 38551(b). ARB is also required to adopt regulations to achieve the maximum technologically feasible and cost-effective GHG emissions reductions. *Id.* § 38560. In addition to the foregoing, ARB believes that the pre-AB 398

version of Health & Safety Code section 38562(c) provided sufficient authority for ARB to initiate this rulemaking and promulgate the Proposed Amendments.

Moreover, recently enacted AB 398 amended Health & Safety Code section 38562(c) to expressly support ARB's authority to continue the Cap-and-Trade Program post-2020. With this express statutory support in AB 398, and building upon the existing provisions of AB 32, ARB has clear legal authority to implement a Cap-and-Trade Program post-2020 and promulgate the Proposed Amendments.

Additionally, AB 398 was passed with a two-thirds supermajority vote of the Legislature. Without taking any specific view on whether extending the Cap-and-Trade Program post-2020 would have raised Proposition 26 considerations, there can be no doubt that ARB has constitutional authority to promulgate the Proposed Amendments in light of the two-thirds supermajority vote enacting AB 398.

Finally, one commenter suggests that ARB, in pursuing a Clean Power Plan compliance plan based on state measures, must identify the specific laws and/ or regulations that achieve the State's required emissions reductions. 40 C.F.R. § 60.5745(a)(6)(i) requires ARB to identify "the applicable State laws or regulations related to such measures" (emphasis added). ARB satisfies this requirement by identifying the Cap-and-Trade Regulation in its Clean Power Plan compliance plan. Based on the above, ARB staff declines to incorporate the commenters' views that the amendments should not move forward.

K-1.9. Multiple Comments:

The State Board Must Prioritize Direct Emissions Reductions.

Assembly Bill 197 recently became law and expressly directs the State Board to prioritize direct emissions reductions at large stationary sources. The ISOR rejects direct emissions reductions in favor of Cap and Trade without any effort to identify or prioritize those regulatory strategies. ISOR at 306-307. The State Board has no authority to disregard direct emissions reduction strategies for the purposes of meeting the additional reductions required by Senate Bill 32. Rather, the Board must prioritize "emissions reduction rules and regulations that result in direct emission reductions at large stationary sources of greenhouse gas emissions[.]" Stats. 2016, ch. 250, § 5, subdivision (a), p. 92 (codified as Health & Safety Code § 38562.5(a)). The State Board may not proceed with the Proposed Amendments, which plainly do not comport with AB 197. (JOINTENVJUSTICE)

Comment:

Now, the legislature is instructing you to regulate greenhouse gas emissions with -- even more assiduously than you have been doing since 2008, and they have not

instruct you to continue a Cap-and-Trade Program. In fact, they've instructed you to pay more attention to direct emissions. (COMMBETTENV)

Response: Commenters assert that a recently enacted law bars the use of a Cap-and-Trade Program. Contrary to these comments, and as indicated in the Second Notice of Public Availability of Modified Text for this rulemaking, Assembly Bill 197 (AB 197, Garcia, Chapter 250, Statutes of 2016) provides that, when adopting rules and regulations pursuant to Division 25.5 of the Health and Safety Code to achieve emissions reductions beyond the 2020 statewide greenhouse gas limit, ARB shall follow the requirements in Health and Safety Code section 38562(b), consider the social costs of the emissions of greenhouse gases, and prioritize emissions reduction rules and regulations that result in direct emission reductions from various sources.

ARB designed the Cap-and-Trade Regulation taking into account section 38562(b).⁵³⁰ The Proposed Amendments retain and extend the major elements of the Regulation, including those features bearing on section 38562(b) considerations. In addition, ARB has considered the social costs of GHG emissions. The social costs of GHG emission reductions from extending the Regulation beyond 2020 can be estimated using the U.S. Government's Interagency Working Group on Social Cost of Greenhouse Gases Social Cost of Carbon (SC-CO₂), which represents the long-term damage done by a ton of CO₂ emissions in a given year and the value of damages avoided for a ton of CO₂ reductions. Avoided social damage of the Regulation in 2030 ranges from \$800 million to \$8.4 billion (2015 dollars).⁵³¹ This range is achieved by multiplying the estimated emission reductions from the Regulation in 2030 (i.e., 45-100 MMTCO₂e) by the 2030 year SC-CO₂ across U.S. EPA discount rates and inflated to 2015 dollars.^{532, 533}

Finally, in developing the regulatory amendments that would take effect post-2020, the proposed declining cap acts to constrain and reduce emissions across the economy to ensure the 40 percent below 1990 level target is achieved, especially if other measures fail to achieve their anticipated GHG reductions. As

⁵³⁰ See Proposed Regulation to Implement the California Cap-and-Trade Program, Staff Report: Initial Statement of Reasons, at II-50-II-53 (2010), *available at* <https://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf>.

⁵³¹ Estimates of the avoided damages resulting from California's climate policies are also discussed in the proposed 2030 Target Scoping Plan, which is referenced in the ISOR and is currently under development. These estimates rely on the SC-CO₂ and they vary across different discount rates, which measure the value of money over time.

⁵³² The U.S. Government SC-CO₂ values are in 2007 dollars. The 2030 SC-CO₂ values of \$16, \$50, and \$73 translate to approximately \$18, \$57, and \$83 in 2015 dollars, respectively, based on the Bureau of Labor Statistics CPI Inflation Calculator.

⁵³³ Chapter VI of the ISOR references the 2030 Target Scoping Plan, which discusses in Chapters 2 and 3 that the Regulation will result in additional GHG emission reductions—and associated avoided social costs—during the 2021-2029 period as well.

designed, the Regulation will ensure GHG emission reductions occur within California that may also reduce criteria pollutants and toxic air contaminants. Sources covered by the Regulation include natural gas and fuel suppliers, large stationary sources, and electricity importers. The gradually declining cap on GHG emissions, along with the quantitative usage limitation for offset credits, means that the proposed amendments would result in direct emission reductions at various covered entities, including large stationary sources and other GHG emission sources. As noted in the ISOR, through 2030, the Cap-and-Trade Program is expected to deliver between 100-200 MMTCO₂e of the cumulative total emission reductions needed between 2021 and 2030 to achieve the 2030 target.⁵³⁴ As such, ARB staff declines to incorporate the commenters' views that the amendments should not move forward.

K-1.10. Comment:

CalChamber strives to remain a productive stakeholder throughout the AB 32 implementation process as well as in the future with post-2020 climate policies, in order to advance the greenhouse gas (GHG) emission reduction goals in the most cost-effective manner while protecting California businesses and allowing for economic growth across all sectors of the economy. We have long maintained that if designed properly, a market-based mechanism has the ability to garner significant GHG reductions in a cost-effective manner.

A cap-and-trade program will be a more cost-effective approach than command and control and less likely to discriminate unfairly against particular industrial sectors. California's greenhouse gas reduction laws post 2020 will be unworkable without a well-designed market mechanism. The command and control measures that would be used to achieve a 2030 GHG emission reduction target of 40% below 1990 levels will be harsh and severely impact the quality of life of Californians. This will require cutting per capita GHG emissions nearly in half over ten years, after already achieving the easiest and most cost effective reductions.

Governor Brown has noted that an extension of cap-and-trade post 2020 is unfinished business. In order for there to be an extension, there needs to be legislative authority. A market mechanism can be adopted with a simple majority vote of the California Legislature, however, if the CARB is looking for a revenue stream beyond the cost of administering the program, this will require a supermajority in order to approve the tax.

⁵³⁴ As discussed above, Chapter VI of the ISOR refers to ARB's development of the 2030 Target Scoping Plan, in which PATHWAYS modeling has confirmed (with further specificity) the GHG emissions reduction estimates contained in the ISOR. Specifically, the Cap-and-Trade Program is expected to achieve 191 MMTCO₂e GHG emission reductions of the cumulative 680 MMTCO₂e GHG emission reductions needed between 2021 and 2030 to achieve the 2030 target.
<https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm>

Our comments below include concerns for some design flaws and recommendations to modify elements to ensure an operable, cost-effective program. (CALCHAMBER)

Response: ARB staff appreciates the commenter's general support for cap-and-trade. With respect to the portion of the comment expressing concerns over legislative authority, see response to 45-day comment K-1.8. This comment also references more specific concerns by the same commenter; those specific comments, and staff responses, are included elsewhere in this FSOR.

K-1.11. Multiple Comments:

LACK OF AUTHORITY FOR POST-2030 ALLOWANCE BUDGETS

Despite the recent passage of SB 32 (Pavley), and beyond the lack of authority for a cap-and-trade program 2020, there is certainly no authorization to establish a GHG emission reduction limit for 2050. We recommend that ARB remove post-2030 caps from this rulemaking. (CALCHAMBERCOMMERCE)

Comment:

ARB Lacks Statutory Authority to Set Post-2030 Allowance Budgets

SB 32 (Pavley) does not authorize the Governor or the ARB to establish a greenhouse gas emissions limit that would be applicable after 2030 – and in passing this legislation, lawmakers made clear that they shall have oversight of climate change policies going forward. We recommend that ARB remove post-2030 caps from this rulemaking. (CCPC)

Response: ARB is the state agency charged with regulating sources of GHG emissions in order to reduce GHG emissions. Health & Safety Code § 38510. ARB's role is not extinguished in 2020 or 2030. Indeed, the Legislature intended, in enacting AB 32, that ARB continue GHG emissions reductions beyond 2020, and later legislation and executive orders confirm that fact. *Id.* § 38551(b); see also Executive Order B-30-15. ARB is also required to adopt regulations to achieve the maximum technologically feasible and cost-effective GHG emissions reductions. Health & Safety Code § 38560. Therefore, ARB has authority to establish a framework for calculating annual allowance budgets for calendars years 2032 to 2050. See also response to 45-day comment K-1.8.

L. ALTERNATIVES TO THE CAP-AND-TRADE PROGRAM

L-1. Direct Reductions

AB 197 and Prioritizing Direct Reductions

L-1.1. Multiple Comments:

The State Board should not continue the Cap and Trade Program post-2020 and should instead institute a program of direct emissions reductions that will benefit the health and

welfare of California communities. Assembly Bill 32 limited the State Board's authority to implement Cap and Trade by codifying a sunset date for the program. Furthermore, the Legislature in Senate Bill 32 directed the State Board to ensure that disadvantaged communities benefit – not suffer – from climate policy. The State Board “shall achieve the state’s more stringent greenhouse gas emission reductions *in a manner that benefits* the state’s most disadvantaged communities and is transparent and accountable to the public and the Legislature.” Stats. 2016, ch. 249, § 1, subdivision (d), p. 88 (emphasis added). In Assembly Bill 197, the Legislature directed the State Board to *prioritize* direct emissions reductions. (JOINTENVJUSTICE)

Comment:

California Must Prioritize Direct Reductions

The California Legislature recently adopted, and Governor Brown has since signed, Senate Bill 32, legislation requiring California to reduce emissions 40 percent below 1990 levels by 2030. Stats.2016, ch. 249 (Sen. Bill 32), § 2 (Health & Saf. Code § 38566, eff. Jan. 1, 2017). However, that law is conspicuously silent on the role of the cap-and-trade regulation in achieving these increasingly steep reductions after 2020. Specifically, SB 32 did *not* identify cap-and-trade as a vehicle for attaining those goals. Moreover, Assembly Bill 197—companion legislation to Senate Bill 32, and also recently signed into law by Governor Brown—specifically requires the Air Resources Board to prioritize “direct emission reductions” in achieving reductions beyond the 2020 limit. Stats.2016, ch. 250 (Asm. Bill 197), § 5 (Health & Saf. Code § 38562.5, eff. Jan. 1, 2017).

The Proposed Amendments must be considered—and revised—in light of the specific direction and authority provided in SB 32 and AB 197. Specifically, the Proposed Amendments must be revised to prioritize direct emission reduction rather than increased reliance on out-of-state carbon offsets. (CBD)

Comment:

Assembly Bill 197 expressly directs the State Board to prioritize direct emissions reductions at large stationary sources, and these regulations do not comport with that authority. AB 197 was recently signed into law by Governor Brown. Under it, the Board must prioritize “emissions reduction rules and regulations that result in direct emission reductions at large stationary sources of greenhouse gas emissions.” The staff recommendation to extend the cap and trade regulations rejects direct emissions reductions in favor of Cap and Trade without any effort to identify or prioritize those regulatory strategies. (CEJA)

Comment:

Moreover, AB 197 specifically directed this Board to prioritize direct emissions reductions. Nothing in this rule-making does that. Of course, that law just was signed, and this proposed rule came out before the law was signed. However, staff didn't

mention this thing at all during its presentation. They haven't discussed that point at all. You have to prioritize direct reductions, even assuming cap and trade gets extended. There's something fundamentally wrong with the way that the Board is moving forward. (CENTRACEPOVENV)

Comment:

Our communities are in extreme health at this moment to better help their environment and their health. In my county, this month alone, our children had spent about 40 percent of their time inside of their classrooms because of the poor air quality. We're not receiving any benefits of cap and trade. And if you think we are, let us know, because we're not seeing them. There's people benefiting from this, and most of the times it's the industry and their pockets, but not the health and not the children that are in the emergency room almost on a daily basis because of their asthma attacks. (CENTRACEPOVENV3)

Comment:

Cap and trade ignores the reality that locality -- that location does matter. The trade of contamination leaves the great contaminators, great polluters who are found in the communities of environmental justice without any responsibility. They don't take any responsibility. It allows them to buy credits at a very cheap rate or save credits that they obtained freely, so they continue to pollute instead of cleaning up their dirt -- their mess. The petroleum refineries, the energy plants, the petroleum producers and other polluters concentrated in communities of color and low income have bought the right compensations, okay, such as the reforestation of the forests outside of the State, instead of cleaning California. (RUIZ)

Comment:

We respectfully urge the ARB to prepare implementing direct source control measures, post-2020. We see the recent passage of SB 32 and AB 197 and their stated priority for direct source emissions reductions as the best case scenario for California.

Because cap and trade places additional burdens on front-line communities, and is less effective at reducing emissions than tried and true direct source regulations. Also, the legislature has not authorized this Board to extend cap and trade post-2020.

Cap and trade undermines the most important tenet of the Clean Air Act, which is that companies do not have the inherent right to pollute our airways. By allowing polluters to purchase the right to continue polluting our airways, we harm our communities, public health, and our climate.

The growing urgency of climate change means that we cannot afford another decade experimenting with unpredictable market-based approaches to our climate problems. We respectfully ask the ARB to turn away from cap and trade with all of its volatility,

potential for fraud, lack of transparency, and implement direct emissions reductions at the source for a transparent, accountable, and equitable approach. (FOODWATER)

Response: Commenters assert that recently passed Senate Bill 32 and Assembly Bill 197 should be read to not allow the amendments in this rulemaking that extend the Cap-and-Trade Program beyond 2020, and that AB 32 does not authorize an extension beyond 2020. With respect to the comments regarding post-2020 authority and AB 32, please see response to 45-day comment K-1.8.

As noted by commenters, Senate Bill 32 establishes the 2030 greenhouse gas reduction target of 40 percent below 1990 levels by 2030, and Assembly Bill 197 directed ARB to prioritize emission reduction rules and regulations that result in direct emission reductions at large stationary sources, from mobile sources, and from other sources. Other commenters have also referenced testimony and a letter by Eduardo Garcia, the author of AB 197, indicating that “the intention [of AB 197] is by no means to tamper with the Cap-and-Trade Program.” See first 15-day comment K-1.3.

As indicated in the ISOR and the Second Notice of Public Availability of Modified Text for this rulemaking, the 2017 Climate Change Scoping Plan Update includes ARB’s strategy for achieving California’s 2030 greenhouse gas target. The proposed 2017 Scoping Plan Update includes policies in the Proposed Scoping Plan Scenario that prioritize rules and regulations that result in direct emission reductions at some of the State’s largest stationary sources and mobile sources. Examples of these policies include:

- Advanced Clean Cars regulations will result in direct emission reductions in the light-duty vehicle sector.
- Enhanced LCFS will result in direct emission reductions in light-duty and heavy-duty transportation.
- SB 350, the Renewables Portfolio Standard, and energy efficiency will result in direct emission reductions from fossil fuel-fired power generation.
- Refinery regulations will result in direct emission reductions from refineries.
- The Cap-and-Trade regulation constrains and reduces emissions from sources that constitute approximately 80 percent of California GHG emissions, resulting in direct emission reductions from covered entities.
- SB 1383 and the Short-lived Climate Pollutant Reduction Strategy require emission reductions in the agricultural, commercial, residential, industrial, and energy sectors.

In addition, the proposed 2017 Scoping Plan Update considers alternative scenarios for achieving the Senate Bill 32 goal of reducing greenhouse gas emission by 40 percent below 1990 levels by 2030. Some of the alternatives were not responsive to AB 197 because they did not prioritize direct greenhouse

gas reductions at large stationary sources or did not satisfy other ARB criteria (e.g., the likelihood of the scenario achieving the 2030 GHG emissions reduction goal) and, as such, were not ultimately recommended. As the proposed 2017 Scoping Plan Update indicates, the issue of the certainty of GHG emission reductions is paramount, and alternatives vary greatly as to the certainty of meeting the 2030 target. The Proposed Scoping Plan Scenario—including extending the Cap-and-Trade Program—was found to be the scenario that would best ensure the achievement of required GHG emission reductions.

Furthermore, as required by the APA, ARB evaluated alternatives to the Proposed Amendments in the ISOR: a “no project” alternative (i.e., no Cap-and-Trade Program and no replacement thereto), a facility-specific reductions alternative, and a carbon fee alternative. In evaluating these alternative approaches to the Proposed Amendments, ARB staff found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. Namely, ARB considered an alternative where it would cease to operate the Cap-and-Trade Program and would instead implement facility-specific requirements designed to achieve the same amount of estimated emissions reductions (i.e., 40 percent reduction by 2030). This alternative was rejected because it increases costs, reduces flexibility, and could generate more emissions leakage compared to the proposed Cap-and-Trade Program. Additionally, the carbon fee alternative was rejected because it would not guarantee that California would meet its GHG reduction goals.

See also response to 45-day comment K-1.9. For all of these reasons, ARB staff declines to incorporate commenters’ request to not move forward with the amendments in this rulemaking.

Combining Alternative Proposals

L-1.2. Comment:

So I see both the heavy fossil fuel polluters like oil refiners and the burgeoning solution we have which is clean electricity, and renewable electricity. We have oppose cap and trade, but staff did identify good alternatives that it found feasible in the concept paper, including a high transportation option, electrifying transportation, and also another one that focused on industrial pollution.

We propose that you combine these using direct cuts in economy wide pollution reduction in fossil fuel phase-out, which your own modelers found is feasible using existing technology without lifestyle changes and found to be economical. This would use aggressive energy efficiency, electrification of transportation and de-carbonization of the grid.

Regarding the first question the Board made to staff about what percent cap and trade cover, staff implied, as a preliminary matter, that cap and trade would only be a smart of

these State measures, but you should know that for industrial measures, in the last scoping cap and trade was the whole shebang. We didn't get anything else for industrial pollution cuts, except cap and trade. Most of the other measures were transportation. So it's not very comforting for us to know that cap and trade would be just a small piece. For industrial measures, that's all we got before.

Despite decades of exposure to refineries, I still get shocked when I'm rime in the community, for example, Wilmington where there's 5 oil refineries. People have oil drilling literally in their backyard, diesel trucking, ports, smells flaring. It's truly intolerable with high asthma rates, and that's just one community.

On the ground, the air districts do a lot. We applaud and work with the air district. But they're set up to limit emissions, not to do energy transformation. And CARB has the mandate for energy transformation, and that's what we really need to do.

In conclusion, I don't think we're going to clean up the smog without the energy transformation.

And we can't clean up the greenhouse gas cuts without ditching cap and trade. (CBE)

Response: The commenter appears to be advocating for adopting one or more of the alternatives contained in the ISOR. For a description of why ARB staff rejected the alternatives as not achieving the objectives of the rulemaking, see the ISOR as well as response to 45-day comment L-1.1. Moreover, staff notes that the Cap-and-Trade Program places a limit on greenhouse gas emissions and, by virtue of the declining cap on emissions and the quantitative usage limitation on the use of offsets, decreases greenhouse gas emissions statewide. With respect to portions of the comment seeking broader transformative changes, the proposed 2017 Scoping Plan Update, referenced in the ISOR, identifies additional measures that will reduce greenhouse gas emissions specifically in the industrial sector. These include a 20 percent reduction by 2030 in GHG emissions in the refinery sector from 2014 levels. With respect to this specific rulemaking, while ARB has broad authority to regulate GHG emissions, it does not have a generalized mandate for energy transformation, as the commenter suggests. ARB must only analyze reasonable alternatives to the Proposed Amendments, which it has done in the ISOR.

Prioritizing a Just Transition

L-1.3. Multiple Comments:

Cap and trade ignores the reality that location matters... We want a State plan that cleans up State air and local air. We want to actively work towards slowing down climate change, and cap and trade doesn't do this. We want a just transition. A just transition that builds a green economy, will create and maintain local jobs via community-owned renewable energy. And this shift will ensure that revenue stays within the community and supports the community. Transformation such as just transition is

empowering, equitable, creates resilient jobs, improves local economy, and does not put residents health in jeopardy. Can and trade doesn't do this. We urge the Board to take its residents well-being into consideration and support a just transition to clean energy. Yes, cap, and no trade. (COMMBETTENV2)

Comment:

So I'm happy to be up here, where I can breathe comfortably. I wanted to just highlight a couple of the Cushing report's findings, particularly around co-pollutants. The first compliance period reporting data show that cement in-State electricity generation and oil and gas production and supplies, and hydrogen plant sectors have increased greenhouse gas emissions over their baseline period within California. And while GHG emissions are not of a particular health concern, what is of concern is that there's a correlation, as the report finds, between particulate matter and greenhouse gas emissions in the largest facilities. And that is a health concern for localized communities, particularly the low-income communities, and communities of color that are at the fence line of those facilities. And also, unfortunately not surprising, but the correlation between where those facilities are sited and the top 20 percent of CalEnviroScreen communities is also something for the Board to look at, because our goal is to decrease the number of impacted communities, not increase them with localized pollution. And so I think the correlation between the CalEnviroScreen communities and the facilities that are under the Cap-and-Trade Program is also really important. I think there are many tools available to California to look at what a holistic just transition would be for these communities. CalEnviroScreen is one, but there's a whole host of things that the State is looking at. SB 32 and AB 197 provides a framework. And I think Diane's question to the Board is very well taken is how are these being prioritized, how are they being integrated, and how are we creating a plan that moves everyone in California forward? Particularly the communities that have historically been hit first and worst by the fossil fuel economy, how do we make sure they're at the front of the line as we transition to a new community -- a new California, new fuel, new energy, new ways of producing food that benefit everybody. (CENTRACEPOVENV5)

Response: A cap without trading is similar to a Cap-and-Tax proposal contained in the proposed 2017 Climate Change Scoping Plan Update. To the extent this comment is referencing the Scoping Plan Update Process (which is separate from this rulemaking amendment process), ARB staff notes that the proposed 2017 Scoping Plan Update evaluated numerous scenarios that would achieve the 2030 greenhouse gas reduction target. One scenario included the Environmental Justice Advisory Committee (EJAC) recommendation of a Cap-and-Tax. Economic modeling shows that Cap-and-Tax is the least cost-effective alternative to achieved the State's 2030 target. The Cap-and-Tax alternative would introduce two costs—(1) onsite investments for reductions at a higher cost or reductions in production, and (2) a carbon tax for actual emissions paid to the

State—that must be absorbed by the covered entity or passed on to consumers. Some sources may not be able to achieve a required percent reduction in GHGs each year, forcing them to cut production to meet their annual caps, potentially affecting jobs and the price of their products. This would negatively impact the California economy and not necessarily reduce global GHG emissions.

ARB also evaluated a carbon fee alternative and a direct facility-specific emissions reduction alternative to the Proposed Amendments in the ISOR, but found that these alternatives would increase costs and may not achieve required GHG emission reductions. ARB hereby incorporates by reference its response to 45-day comment L-1.1 regarding the alternatives it considered in the ISOR.

Regarding one commenter's reference to the Cushing report, though the Cushing report looks at the correlation between greenhouse gas emissions and air quality from facilities covered by the Cap-and-Trade Program, the report also states: "Further research is needed before firm policy conclusions can be drawn from this preliminary analysis." Consistency among greenhouse gas, criteria pollutant, and toxics emissions data is important to aggregating, normalizing, and evaluating the information, as is having a time series of data longer than a couple of years. Assembly Bill 197 directs ARB to make available data of greenhouse gas, criteria pollutant, and toxic air contaminant data by 2018, and staff is taking necessary steps to do so. Please see also response to 45-day comment K-1.5.

Lastly, with respect to the comments regarding Assembly Bill 197, please see responses to 45-day comments K-1.9 and L-1.1.

Mitigating New GHG Emission Sources

L-1.4. Comment:

All new greenhouse gas sources must be mitigated. (EJAC)

Response: The Cap-and-Trade Program is one of a suite of measures to mitigate greenhouse gas emissions, including emissions from new sources if those new sources exceed the emissions thresholds, to meet the State's greenhouse gas reduction targets. Other programs are discussed in the 2017 Climate Change Scoping Plan Update, some of which are discussed in response to 45-day comment L-1.1.

Sector-Based Offsets and Hybrid Approach

L-1.5. Comment:

While National Wildlife Federation supports the inclusion of REDD offsets in California's cap-and-trade scheme, we also understand the concerns expressed by environmental justice groups in California. If and when California links with international tropical forest offset programs, we believe that the market based mechanism must be approached with a social justice policy framework. This is essential in the arena of climate change,

since global warming disproportionately affects the poor, as has been well documented in the scientific literature. Many experts agree that poverty is a primary stressor which can increase vulnerability to climate change because poor communities have the highest levels of exposure to climate hazards yet have the lowest capacity to cope and adapt to these changes. In fact, the World Bank estimates that the poorest populations will bear 75-80% of the costs and damages caused by future climate changes.

Many polluting industries, especially large emitters of GHG gases, are located in poor and disadvantaged communities. Therefore, we recommend that an expansion of California's cap-and-trade system to include forests be accompanied by clarification, and increased enforcement where needed, of site specific measures within California which have tangible health benefits for at-risk communities. This would include, for example, application of mercury rules to restrict emissions from individual power plants.

Moreover, the National Wildlife Federation urges that the overall cap-and-trade program distribute substantial portions of the revenues resulting from offsets to vulnerable populations within California, so they can address environmental and social priorities pertinent to their communities. (NWF)

Response: ARB staff appreciates the commenters support of sector-based offsets in the Program, although that has not been proposed as part of this rulemaking. Greenhouse gases (GHGs) are a global pollutant that do not pose direct health risks like criteria and toxic air pollutants. ARB agrees that reducing exposure to criteria and toxic air pollutants is necessary to protect residents in disadvantaged communities. These communities have historically been located close to large stationary and mobile sources of emissions, a reality that predates the implementation of the Cap-and-Trade Program. The State has implemented several policies and programs to directly address criteria and toxics air pollutants. Significant progress has been made in reducing diesel particulate matter (PM) and many other hazardous air pollutants. For example, and based on the most current CEPAM inventory (2016 SIP inventory tool V. 1.05), statewide NOx emissions have been reduced by 26 percent between 2012 and 2017, and diesel PM has been reduced by 50 percent over the same period.

ARB partners with air districts to address stationary emissions sources and adopts and implements State-level regulations to address sources of criteria and toxic air pollution, including mobile sources. The key air quality strategies being implemented by ARB include the following:

- **State Implementation Plans.** As referenced in the ISOR, the 2016 State Strategy for the State Implementation Plan and proposed control measures designed to achieve the emission reductions from mobile sources, fuels, stationary sources, and consumer products necessary to meet ozone and fine PM attainment deadlines established by the Clean Air Act.

- **Diesel Risk Reduction Plan.** As referenced in the 2010 ISOR to the Cap-and-Trade Regulation and the functional equivalent document incorporated by reference in the EA, California's Diesel Risk Reduction Plan recommends many control measures to reduce the risks associated with diesel PM and achieve a goal of 85 percent PM reduction by 2020. Diesel PM accounts for of the majority of cancer risk for background ambient air.
- **Sustainable Freight Action Plan.** As referenced in the EA, Executive Order B-32-15 required the development of an integrated Sustainable Freight Action Plan, which seeks to improve freight efficiency, transition to zero emission technologies, and increase competitiveness of California's freight system.
- **AB 32 Scoping Plan.** As referenced in the ISOR and in the EA, the original (2008), first update (2014), and ongoing update to the Scoping Plan (2016-17) contain the main strategies California will use to reduce the GHGs that cause climate change and achieve the State's climate goals.
- **AB 1807.** As referenced in the EA, AB 1807 requires ARB to use certain criteria in prioritizing the identification and control of air toxics.
- **AB 2588 Air Toxics "Hot Spots" Program.** As referenced in the EA, AB 2588 imposes air quality requirements on the state. The goals of the program are to collect emission data, identify facilities having localized impacts, ascertain health risks, notify nearby residents of significant risks, and to reduce those significant risks to acceptable levels.

To support efforts to advance the State's toxics program, OEHHA finalized a new health risk assessment methodology on March 6, 2015. In light of this, ARB is collaborating with air districts in the review of the existing toxics program under AB 2588 to strengthen the program.

The commenter urges that the Cap-and-Trade Program be combined with site-specific measures, including application of mercury rules. On this point, ARB notes that this comment is outside of the scope of the current rulemaking. Notwithstanding this, ARB has proposed a 20% reduction in emissions from refineries in the Proposed Scoping Plan Scenario in the proposed 2017 Scoping Plan Update. With respect to mercury rules, ARB staff notes that the U.S. EPA's Mercury and Air Toxics Standards (MATS) only applies to coal-fired power plants, not other large stationary sources.

The commenter also provides recommendations on use of Cap-and-Trade Program funds for addressing environmental and social priorities for vulnerable populations. These recommendations are outside the scope of this rulemaking, since auction proceeds are subject to the appropriation authority of the Legislature and the Governor through the budgeting process. Pursuant to State law, Cap-and-Trade auction proceeds are deposited into the Greenhouse Gas Reduction Fund (GGRF), appropriated through the State budget by the

Legislature and the Governor, and used to facilitate the achievement of GHG emission reductions. A minimum of 25 percent of GGRF monies must be invested in projects that are located within and benefiting individuals living in disadvantaged communities; an additional 5 percent must be invested in projects that are located within and benefiting low-income communities or benefiting low-income households statewide; and an additional 5 percent must be invested in projects located within and benefiting low-income communities, or benefiting low-income households, that are within a half mile of a disadvantaged community.

Hybrid of GHG and Local Pollutant Reductions

L-1.6. Multiple Comments:

...yes, we do have to consider health costs as we think about what's cost effective. And so as we've heard today and as we've known for some time, there are too many communities in California that face serious air quality problems. And those impacts are disproportionately born, and we actually have to do something about that. And what we as EDF would likely like to see is an inclusive set of solutions that includes the benefits of cap and trade, but also allows us to address those reductions in local air pollutants that definitely need to happen. (EDF2)

Comment:

We were very happy to see, in those concepts around the scoping plan, that we had begun to look at a more hybrid approach that really asked the questions that we've been asking, what's happening in low-income communities? And now you have what we in public health call early warnings. So you have your own adaptive management data that seems to indicate some increases in some areas. Is that definitive scientific proof that this is happening? No, but it bears out the limited experiences of people who live next to these traded facilities. And the second earlier warning is the report that has just been produced out of USC. And those of you who understand public health know the importance of acting on early warnings. And those of us from the environmental justice community wanted you to have these early warning datas, so that we can begin to change the program where it needed to be -- where it needs to be change. We think that the trading program is not -- has not given us the kinds of deep rapid reductions that we need to address climate change, or that we need to address the driver of health disparities that is air pollution. We warned against separating climate emissions from air quality...

We want a just transition to a new economy. This economy has not worked for most people of color and low-income communities. It has not meant more wealth. And with all due respect to all the discussion about jobs, those jobs are not in the communities and they're not building wealth in our communities, so -- and the other thing I want to say is that the environmental justice community stood up for AB 32. There are people in this room who walked precincts, who knocked doors, who talked to the press, and we defended AB 32. We ask the Board now to stand with environmental justice

communities and fix this program. Give us a program that does direct emissions reductions, funds the just transition to a green economy, so that we afford to breathe and have a job. (EJAC3)

Comment:

I'm here today to ask that the ARB consider taking a different approach to reducing greenhouse gases. Cap and trade is not working as intended. In communities like Pacoima, we have to see any sustainable benefits from the market-based approach. The health and quality of life of people in Pacoima and many communities like Pacoima cannot depend on trade and auction outcomes. Organizations like ours and many here today want to work with the ARB to create a comprehensive hybrid strategy that gets us to our goals, while providing really, sustainable, health, job, housing, and greening outcomes. (PACBEAUTIFUL)

Response: Commenters express a desire to see both greenhouse gas and criteria and toxic air contaminant reductions. Several commenters express concerns with the functioning of the Cap-and-Trade Program. Other comments appear more directly directed at the ongoing 2017 Scoping Plan Update process. With respect to comments concerning the functioning of the Cap-and-Trade Program, see response 45-day comment K-1.3. ARB staff agree with the commenters that reducing exposure to criteria and toxic air pollutants is necessary to protect residents in disadvantaged communities. See response to 45-day comment L-1.5 and 45-day comment K-1.5 for more detail.

L-2. GHG Emissions Pricing Alternatives

Support for Cap and Dividend

L-2.1. Multiple Comments:

The State's current plan is to devote hundreds of millions of dollars from Cap & Trade funds towards high-speed rail and transit-oriented development, as well as other projects. These may be fine projects in and of themselves, but by what metrics are they the best uses of Cap-and-Trade funds? One reason for skepticism is that due to the economics of Cap and Trade, using permit revenues for projects that reduce emissions may only shift emissions between sectors under the cap. Emission reduction projects in certain sectors may reduce the price of the permit in that sector, but this only serves to create space under the cap that will be filled by emissions from other sectors. The overall level of emissions is determined by the cap, not by the price of the permit. Certainly collective action is required to meet long-term climate goals, but returning a majority of permit value back to households, and making those dividends taxable would boost tax revenues, allowing the State to still put forth projects. I request ARB respond to this issue in its communications regarding the post-2020 Scoping Plan and other documents. I also request ARB staff inform the Governor, the Legislature, and the public about the Cap & Dividend model as an alternative (and simpler) solution to

implementing a carbon price to meet the goals of AB32 and SB32. Given the current program's legal uncertainties, passing another bill with a two thirds majority may be required anyway, and the dividend approach should be an option.

Climate dividends are similar to anti-poverty movements focusing on the concept of "basic income," and international development efforts promoting "unconditional cash transfers." It would be congruent with the State's efforts at establishing a State Earned Income Tax Credit (EITC)⁵³⁵. (SANDLER)

Comment:

We also demand that our nation mobilize to reduce GHG emissions supporting Citizens' Climate Lobby that is creating the political will for congress to act.

We are studying metrics and rewards for carbon sequestration in local Climate Action Plans. We love the iMatterYouth.org kids giving out climate report cards.

Help stop GHG emissions by joining Citizens' Climate Lobby at citizensclimatelobby.org and contact me to learn how to reward stewards of living soil...

[The commenter attached the following statement from the Citizens' Climate Lobby:]

Carbon Fee and Dividend

A fair, simple climate solution

- Place a fee on fossil fuels at the source (mine, well or port)
- Return 100% of the revenue to U.S. households
- Apply, a border adjustment to discourage businesses from relocating to where they can emit more CO₂ and to encourage other nations to adopt an equivalent price on carbon

Stabilize the Climate and Boost the Economy

- Cut greenhouse gas emissions by 50% in 20 years
- Create 2.8 million jobs, boost our GDP and save 200,000 lives

(RINCON-VITTOVA)

Response: The commenters support a cap and dividend program, over a cap-and-trade program. See response to comment L-1.1 for detail on ARB's alternatives analysis and rationale for rejecting alternatives in this rulemaking. With respect to the comments regarding the use of auction proceeds, ARB staff

⁵³⁵ <http://calbudgetcenter.org/blog/proposed-state-eitc-would-significantly-boost-the-incomes-of-californias-lowest-earning-workers/>
http://www.mercurynews.com/california/ci_28114306/california-budget-brown-set-release-revised-spending-proposal

notes that the objective of the Cap-and-Trade Program is to work in complement with California's other climate programs, and to ensure that California reduces greenhouse gas emissions to 1990 levels by 2020 pursuant to Assembly Bill 32 and to assist in achieving further reductions, such as a 40 percent reduction below 1990 levels by 2030 as codified in Senate Bill 32. Pursuant to State law, Cap-and-Trade auction proceeds are deposited into the Greenhouse Gas Reduction Fund (GGRF) and used to facilitate the achievement of GHG emission reductions. A minimum of 25 percent of GGRF monies must be invested in projects that are located within and benefiting individuals living in disadvantaged communities; an additional 5 percent must be invested in projects that are located within and benefiting low-income communities or benefiting low-income households statewide; and an additional 5 percent must be invested in projects located within and benefiting low-income communities, or benefiting low-income households, that are within a half mile of a disadvantaged community. The expenditure of the funds is not the main objective of the Cap-and-Trade Program, and is subject to appropriation authority of the Legislature and the Governor, but ARB believes that expenditures from the GGRF further state climate policy and comply with applicable law regarding the use of auction proceeds. With respect to the comment suggesting the implementation of border carbon adjustments, ARB staff notes that this is outside the scope of what has been proposed in this rulemaking.

Support for Carbon Fee

L-2.2. Multiple Comments:

A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. (EJAC)

Comment:

The scoping plan process is going forward, yet this Board is moving forward with cap and trade as if that is exactly what it wants to do. And finally, for many now, the revenue generated by this program is the reason to continue its existence. There is a far better way to price carbon than cap-and-trade auction revenue. Direct carbon pricing is what we support. (CENTRACEPOENV)

Comment:

I oppose cap and trade, because it's an ecological and economic shell game. Viewing with a broad perspective, we must have a federal price on carbon. That trigger will -- that will trigger comparable national carbon pricing around the world. A carbon tax works better, because trading systems are easy to scam, which we see that that's what has happened. In India, for instance, will be forced to have an effective carbon pricing mechanism in order to sell us their stuff. We want to be a model for countries like India.

A simple transparent policy instead of one that costs a great deal, takes years to set up, and does not bring down emissions as hoped, and allows toxic hot spots near poor people from a pay-to-pollute policy. The California legislature passed a resolution urging Congress to enact a revenue neutral carbon tax. I urge the ARB to consider a similar carbon tax. California is accumulating revenue for investments in technology and environmental justice, because politically we don't have to have a system that is revenue neutral. However, the economic impacts of a revenue neutral system warrants study. Our carbon fee and dividend is an economic stimulus that provides comprehensive economic production for more than half of the population. So as you develop a program that protects environmental justice communities, I'm confident that a federal carbon fee and dividend will be operating to protect the poorest of the poor. (WHITEHURST)

Response: A cap-and-trade program and a carbon tax are both carbon pricing mechanisms, but there are important differences. A cap-and-trade program sets a declining emissions cap so that the maximum allowable GHG emission level is known and covered entities will have to reduce GHG emissions. With a carbon tax, there is no mechanism to limit the actual amount of GHG emissions either at a single source or in the aggregate, and a carbon tax requires entities to pay for all of their GHG emissions directly to the State. In other words, a cap-and-trade program provides environmental certainty while a carbon tax provides some carbon price certainty. There is no emissions limit with a carbon tax, and commenters have presented no evidence indicating that it would be more effective in reducing co-pollutant emissions in disadvantaged communities than the Cap-and-Trade Program.

Furthermore, as required by the APA, ARB evaluated alternatives to the Proposed Amendments in the ISOR: a “no project” alternative (i.e., no Cap-and-Trade Program and no replacement thereto), a facility-specific reductions alternative, and a carbon fee alternative. In evaluating these alternative approaches to the Proposed Amendments, ARB staff found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. Namely, the carbon fee alternative was rejected because it would not guarantee that California would meet its GHG reduction goals.

L-3. Multiple, Mixed or Additional Strategies

Alternatives to Cap-and-Trade

L-3.1. Comment:

The Scoping Plan Economic Analysis must consider carbon tax, command and control regulation, and Cap-and-Dividend or Fee-and-Dividend. Cap-and-Trade must be eliminated. (EJAC)

Response: ARB notes that this comment is outside the scope of the Proposed Amendments as it is made specifically with respect to the Scoping Plan Economic Analysis. Regardless, the 2017 Climate Change Scoping Plan Update evaluated various alternatives to extending the Cap-and-Trade Program: a carbon tax, prescriptive regulations without a market mechanism, and cap-and-tax. Based on ARB's evaluation, the scenario that included extending the Cap-and-Trade Program (i.e., the Proposed Scoping Plan Scenario) best satisfied the following criteria:

- Ensure the State reduces GHGs to meet the 2030 target
- Provide air quality co-benefits
- Prioritize rules and regulations for direct emission reductions
- Provide potential to protect against emissions leakage
- Support the development of integrated and cost-effective regional, national, and international GHG reduction programs
- Invest in disadvantaged and low-income communities
- Minimize impacts of climate change on public health
- Provide compliance flexibility
- Support the Clean Power Plan and other federal climate programs

Additionally, ARB notes that it evaluated alternatives to the Proposed Amendments in the ISOR: a "no project" alternative (i.e., no Cap-and-Trade Program and no replacement thereto), a facility-specific reductions alternative, and a carbon fee alternative. In evaluating these alternative approaches to the Proposed Amendments, ARB staff found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. For these reasons, ARB staff declines to incorporate the commenters' request to eliminate the Cap-and-Trade Program.

Requested Additional Features

L-3.2. Comment:

A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. In addition:

- a. Increase enforcement of existing environmental and climate laws, increasing penalties for violations in DACs.
- b. Establish a state run "Carbon Investment Fund" allowing the private financial sector to invest in Carbon Futures. Pay dividends through enforcement fines, permit fees and carbon tax receipts...

- d. Place individual caps on emission sources, rather than using a market-wide cap. Set up a per-facility emissions trigger that will tighten controls when a certain level is reached.
- e. Establish a moratorium on refinery permits.
- f. Set goal of 50% emissions reduction in Oil and Gas sectors by 2030. Aggressively reduce emissions from these sectors, including fugitive and methane emissions from extraction and production.
- g. Put emissions caps on the largest polluters...
- j. Do not allow regulated entities to apply for California Climate Investments funding... (EJAC)

Response: As discussed in Response to Comment L-3.1, alternatives to the Cap-and-Trade Program were evaluated in the 2017 Climate Change Scoping Plan Update and the ISOR for the Proposed Amendments; but, none of these alternatives ensured adequate GHG emissions reductions or otherwise achieved the goals of AB 32.

Regarding the comments on increased enforcement of existing environmental and climate laws and the creation of a Carbon Investment Fund, these comments are beyond the scope of the Proposed Amendments. However, failure to comply with the Cap-and-Trade Regulation may result in enforcement action.

A facility-level or sub-sector cap is not contemplated in the Cap-and-Trade Program. The Cap-and-Tax scenario in the proposed 2017 Scoping Plan Update provides insight into economic sector cap declines, and the economic modeling shows this is the least cost-effective alternative to achieve the State's target. In the ISOR, ARB also considered an alternative where it would cease to operate the Cap-and-Trade Program and would instead implement facility-specific requirements designed to achieve the same amount of estimated emissions reductions (i.e., 40 percent reduction by 2030). This alternative was rejected because it increases costs, reduces flexibility, and could generate more emissions leakage compared to the proposed Cap-and-Trade Program.

Establishing a moratorium on refinery permits is beyond the scope of the Proposed Amendments. ARB regulates greenhouse gas emissions from stationary sources, while local air districts regulate criteria pollutant and toxics emissions through stationary source permitting. ARB recognizes the need to prioritize direct emissions reductions, and as such, in the proposed 2017 Scoping Plan Update has identified a measure to reduce GHG emission in the refinery sector by 20 percent below 2014 levels by 2030.

Finally, the comment regarding prohibiting covered entities from applying for California Climate Investments funding is outside the scope of the Proposed Amendments.

Tier Pricing for Facilities in Environmental Justice Communities

L-3.3. Comment:

Tier pricing for allowances for facilities in EJ communities, making it more expensive to pollute in those communities. (EJAC)

Response: Establishing a tier of prices for allowances, whereby covered entities in disadvantaged communities would be subject to higher allowance prices, is not contemplated in the Proposed Amendments, and is outside the scope of this rulemaking. Notwithstanding, ARB staff notes that as a practical matter, it is unclear how this would function, given that there is an economy-wide market for allowances. To the extent that covered entities in disadvantaged communities could only purchase and sell a separate subset of allowances, this would effectively impose a separate and narrower cap on such entities, and ARB has otherwise rejected sector-specific caps as cost-prohibitive. Additionally, ARB notes that GHGs are a global pollutant that do not pose direct health risks like criteria and toxic air pollutants. The Cap-and-Trade Program is primarily designed to reduce GHGs.

ARB agrees that reducing exposure to criteria and toxic air pollutants is necessary to protect residents in disadvantaged communities. For further response, see response to 45-day comment L-1.1 and 45-day comment K-1.5.

Changing the Structure of the California Climate Credit

L-3.4. Multiple Comments:

Move the Climate Credit Off-bill: The California Public Utilities Commission has mandated utilities return the revenues from their “consigned allowances” back to the ratepayers through a California Climate Credit that appears twice a year on electricity bills. Post-2020 the State could expand that to an off-bill per-capita dividend that would be simple, transparent, and be inclusive of disadvantaged communities not just coastal cities. Please see my comment on the 2013 Investment Plan for additional information on suggestions for how to include a Household Dividend and a Transportation Dividend as steps toward a more general Climate Dividend.⁵³⁶

Many people do not understand climate dividends. It is about transforming the economic system, not about funding specific projects. I urge ARB staff to read Peter Barnes’ books, including *Who Owns the Sky?*, *Capitalism 3.0*, and *With Liberty and Dividends for All*. (SANDLER)

⁵³⁶ <http://www.arb.ca.gov/lists/com-attach/209-ghgreductfund13-VDdQQQNvU20AY1c5.pdf>

Comment:

The California Climate Credit that appears twice a year on electricity bills can be turned into an off-bill per-capita dividend that would be simple, transparent, and inclusive of disadvantaged communities. The State can gain supporters for the program's extension, by moving the funding for environmental programs into the regular budget process and returning Cap & Trade revenues back to people as climate dividends. That would be a much more advantageous use of the funds. (LOSSY)

Comment:

The California Climate Credit that appears twice a year on electricity bills can be turned into an off-bill per-capita dividend that would be simple, transparent, and inclusive of disadvantaged communities. The State can gain supporters for the program's extension, by moving the funding for environmental programs into the regular budget process and returning Cap & Trade revenues back to people as climate dividends. (MEINZEN)

Response: These comments focus on the manner in which auction revenues are dispersed. The California Climate Credit stems from the sale at auction of consigned allowances from investor owned utilities within the State. The design, implementation, and enforcement of the California Climate Credit is under the purview of the California Public Utilities Commission, and is outside the scope of the Proposed Amendments. Auction proceeds from the sale of State-owned allowances sold at auction are a co-benefit of Cap-and-Trade Program. Pursuant to State law, Cap-and-Trade auction proceeds from the sale of these allowances are deposited into the Greenhouse Gas Reduction Fund (GGRF), appropriated through the State budget by the Legislature and the Governor, and used to facilitate the achievement of GHG emission reductions. The expenditure of the funds is not the main objective of the Cap-and-Trade Program, but ARB believes that expenditures from the GGRF further state climate policy and comply with applicable law regarding the use of auction proceeds. See also response to 45-day comment L-2.1.

*Clean Energy Investments***L-3.5. Multiple Comments:**

If we truly want to reduce greenhouse gases, we need to invest in clean renewable energy, on our most impacted communities on the State of California.
(CENTRACEPOENV3)

Comment:

There are better options than cap and trade to reduce greenhouse gases that hurt our health. We know that these other methods work, because clean energy is growing, but we need more support. Instead of blocking the growth of clean energy, when you permit

fossil fuel energy plants, we need to support the growth of clean energy, because it's good for our communities. (MARQUEZ)

Comment:

I come from the County of Kern, one of the most contaminated in the United States. That's why I'm concerned about the industries that are in the cap and trade are found in low-income communities. And those communities are usually people of color. Personally, I suffer from asthma. I don't have medical insurance. At times, I have to make payment plans, and I am surprised that when the auctions are made for carbon dioxide tons, it costs \$12, an exhaler/an inhaler will be \$60 -- cost me \$60. I would like there to be programs that would reduce contamination, such as solar panels and electric cars. (PEREZ)

Response: The comments appear to advocate for investments in renewable energy separate (or in one comment, in place of) the Cap-and-Trade Program. ARB staff notes that the auction proceeds that are raised from the Cap-and-Trade Program fund programs that further reduce GHGs, including through some renewable energy projects. Additionally, there are numerous other State programs that mandate clean energy or provide incentives for cleaner technology deployment, including, but not limited to, the Renewables Portfolio Standard, the Low Carbon Fuel Standard, and the Clean Vehicle Rebate Project. Because there are multiple initiatives seeking to spur (and require) an increase in renewable energy, and the Cap-and-Trade Program acts in complement to these initiatives, ARB staff continues to believe the Cap-and-Trade Program is a necessary measure to ensure the State achieves its greenhouse gas reduction targets.

Home Insulation

L-3.6. Comment:

The other one I want to raise essentially is just the continuing importance of energy efficiency in helping meet the State's climate, energy, and environmental goals. And certainly, if you look at the scoping report, energy efficiency is going to be called upon to achieve at least the amount of greenhouse gas emission reductions as the renewable portfolio standard.

And certainly, that means that insulation is going to have to play a very large role in helping the State achieve its greenhouse gas emission reduction goals overall. And that's especially true in disadvantaged communities, where you have tens of thousands, if not hundreds of thousands, of poor performing under-insulated homes that -- where a retrofit could be a climate resilience and adaptation measure.

And then finally, I want to draw your attention to a study that we helped -- a 2003 Harvard study, we helped update recently called Carbon Reductions and Health Co-benefits from U.S. residential energy efficiency measures. I'll make sure that staff gets a

copy of that. It basically shows that the very large public health benefits from insulating under-insulated homes. (JOHNSMANV)

Response: This comment, which does not appear to suggest any changes to the proposed amendments, pertains to building energy efficiency and, therefore, is outside the scope of the Proposed Amendments. Regardless, ARB agrees that weatherization is one of the solutions to increase building energy efficiency, and thus reduce greenhouse gas emissions. The recently published “Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities” pursuant to SB 350 offers recommendations for increasing access to renewable energy generation for low-income customers, energy efficiency and weatherization investments for low-income customers, and contracting opportunities for local small business in disadvantaged communities. The 2017 Climate Change Scoping Plan Update recommends implementing the recommendations in the study, and in addition, calls for expansion of the State’s Low-Income Weatherization Program (LIWP) to continue to improve energy efficiency and weatherize existing residential buildings, particularly for low-income individuals and households. Finally, the auction proceeds that are raised from the Cap-and-Trade Program fund programs that further reduce GHGs, including the LIWP.

M. PUBLIC PROCESS

M-1.1. Multiple Comments:

Notwithstanding LADWP's support, it is very difficult to assess the full ramifications of the proposed amendments to the California Cap-and-Trade Regulation and whether they are workable, efficient, and provide adequate protections for LADWP's ratepayers, including low income customers because the Regulation is not fully developed, but rather contains over three dozen placeholder clauses and notations of future policy decisions. Many of these placeholder clauses and notations are critical elements of the new regulatory regime that will potentially have major implications for LADWP and other affected entities under the Cap-and-Trade Regulation. To address this issue, we recommend that ARB not rush the regulatory process for amending the Cap-and-Trade Regulation and that, at the very least, the public is allowed sufficient time to comment on the entire rulemaking each time that ARB releases future 15-day amendment packages to the August 2 proposal. (LADWP)

Comment:

Process Concerns. In recent years, ARB staff has shifted away from the historic practice of presenting a fully developed rule for Board consideration, to a sequential process where many important policy, technical and implementation decisions are made after its initial presentation. When this happens, it chops the process up in a piecemeal fashion, with one or more —15-day amendment packages squeezed in between Board

meetings. These packages not only reduce the review and comment period by two-thirds, but they also limit the scope of comments to only those portions of the regulation that ARB staff have identified as being open for review. This Regulation has many complicated components which are interdependent on each other (e.g., cost containment, allowance allocation and cap setting); therefore, commenting on one moving piece while the others may already be set in stone is not an effective way to finalize an economy-shifting regulation. This change in process does a disservice to ARB's many diverse stakeholders and the people of California. In addition, when the Regulation is finally put together for Board consideration at its second hearing, the timing is such that the Board will normally only act on the CEQA responses, and cannot address any outstanding and potentially significant policy or technical issues.

As proposed, this regulation package has over three dozen placeholder clauses, as well as notations of future policy decisions that are dependent on decisions made today (e.g., Electric Distribution Utilities (EDU) Allocation). Therefore, we know that at least one 15-day amendment package is needed before the Regulation is in complete form, and staff has indicated they are planning at least two separate 15-day packages. SCPPA requests that the scope of the first 15-day amendment package include the entire Regulation that was noticed on August 2 to provide the public sufficient opportunity to comment on the entirety of the regulation. Additionally, any narrowing of the scope of subsequent 15-day amendment packages should be carefully reviewed. (SCPPA)

Response: The Administrative Procedure Act (APA) requires, among other things, that ARB give the public notice of its proposed regulatory action, issue the proposed regulatory text along with a statement of the reasons for it, and give interested parties an opportunity to comment for at least 45 days. If a proposed regulation is changed and such change is sufficiently related to the originally proposed text, ARB must make available the full text of the resulting amendment to the public for at least 15 days and respond to comments received regarding the change. In this case, the public has had an opportunity to comment on the initial Proposed Amendments and the two sets of revisions to the Proposed Amendments. Any bracketed text indicating that a provision is subject to review and potential revision in the initial Proposed Amendments that was, in fact, amended was followed by an at least 15-day comment period for such proposed amendment. In fact, the First Notice of Public Availability of Modified Text afforded 30 days of public review and comment. As such, ARB has fully complied with the APA in this rulemaking. Moreover, and notwithstanding one commenter's statement to the contrary, this is the same process ARB has followed for each of the past amendment rulemakings on the Cap-and-Trade Regulation, as well as other regulations.

M-1.2. Comment:

First, while we support proposals that would add flexibility to the regulation, we are on balance disappointed that the proposals increase uncertainty by using placeholders for core program elements. We're concerned that ARB's approach to adopt some amendments in the current 45-day package, and then address placeholders later on in a 15-day package, really creates a great deal of uncertainty and limits the ability of stakeholders to evaluate the packages as a whole.

The placeholder elements are critical and are a critical part of the program implementation. And so we don't think that it's appropriate for a 15-day package, and we would ask that placeholder design elements be evaluated in future workshops and a full 45-day notice and comment periods. (WSPA2)

Response: See response to 45-day comment M-1.1.

M-1.3. Comment:

NCPA urges the Board to ensure that CARB staff has sufficient time and resources to continue to work with stakeholders to develop the appropriate methodology for allocating allowances to the EDUs based on the existing core principles and inclusive of the cost burden associated with the climate change policies and programs discussed above. Furthermore, it is imperative that the stakeholders be given sufficient time to address this issue, including reviewing and assessing any proposed regulatory language. While the Administrative Procedure Act requires that any such revisions be subject to a minimum 15-day comment period,⁵³⁷ given the complexity of this issue, it may be appropriate to allow for more than the minimum time required by law. Just as the allocation of allowances to the EDUs prior to the first compliance period was an important element of the Program's initial success, so too shall be setting the appropriate allocation for EDUs for the period 2021 to 2031. (NCPA)

Response: ARB worked extensively with stakeholders to develop revisions to the methodology for allocating allowances to EDUs for the 2021-2031 period. The EDU allocation methodology has been revised in the Proposed Second 15-Day Modifications in response to stakeholder input. ARB has complied with the APA in making such revisions to the EDU allocation methodology. See also response to 45-day comment M-1.1.

M-1.4. Comment:**3.1 Concerns About the Scope of the Rulemaking Process**

CARB also confirmed that the current regulatory package does not include proposed revisions to other variables in the allowance allocation equation. As CARB is aware, the allocation of allowances to industries is a function of an equation that includes the

⁵³⁷ California Government Code, section 11340 et seq

assistance factor, applicable industry benchmarks, and the cap adjustment factor. Changes to any of these variables will affect the overall allocation of allowances to industries. In the absence of transparency regarding changes to all three of the allowance allocation variables, stakeholders will be unable to determine the overall level of assistance provided to each industry and, therefore, provide meaningful comments about the extent to which the allowance allocation framework is likely to minimize the risk of leakage.

Although CARB confirmed that it will not propose changes to industry benchmarks for the third compliance period (other than those already specified),⁵³⁸ it also indicated that all benchmarks would need to be changed in order to allocate allowances for purchased electricity and that such changes would be part of separate regulatory package.⁵³⁹ In addition, CARB stated that it may be proposing cap adjustment factors for the post-2020 period as part of a 15-day comment period.⁵⁴⁰

Given that the new allowance allocation framework will not be implemented until after 2020, CSCME urges CARB to undertake a separate regulatory rulemaking covering the entire allowance allocation framework, including any proposals relating to all three variables in the allowance allocation equation. (CSCME)

Response: ARB removed all post-2020 industrial allocation from the Proposed Amendments. As indicated in the Second Notice of Public Availability of Modified Text, ARB intends to continue assessment of appropriate calculations of emissions leakage risk for the post-2020 period, and to propose post-2020 assistance factors in a future rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

M-1.5. Comment:

3.1 Concerns About the Timing of the Rulemaking Process

Given the importance of the allowance allocation framework to the economic viability of industries, the integrity of the cap-and-trade program, and the durability of the state's overall approach to reducing GHG emissions, CARB should ensure that all parties have sufficient time and information available to provide meaningful input into the rulemaking process.

Accordingly, CSCME strongly supports CARB's decision not to implement any revised assistance factors ("AFs") for the third compliance period. This delay in implementation provides an opportunity for CARB to continue discussions regarding the allocation

⁵³⁸ ISOR at 32.

⁵³⁹ ISOR at 33.

⁵⁴⁰ ISOR at 30.

framework so that stakeholders have more time to review the leakage studies, reproduce relevant calculations, assess the studies' limitations, and consider the advantages and disadvantages of alternative approaches to measuring leakage risk. This additional time is particularly important given that CARB has not released critical information necessary for stakeholders to assess the proposed regulatory framework, including but not limited to the international market transfer rates estimated in the international leakage study and emissions intensity data.⁵⁴¹

Despite the fact that revised AFs will not be implemented during the third compliance period, CARB appears to suggest in the ISOR that the revised AFs may be proposed as part of a 15-day rulemaking in advance of consideration of the proposed regulatory amendments at the Board meeting in Spring 2017. Given the complexity of the proposed methodology, the significant impact of any change on California industries, and the failure to release key data, a 15-day rulemaking is an inadequate amount of time for stakeholders to understand how the methodology will translate into the actual AFs that will apply to industries and provide CARB with substantive comments. CARB's decision not to implement revised AFs during the third compliance period eliminates the need for a compressed 15-day process and creates an opportunity to adopt a more deliberate process that would provide stakeholders with more time to review and provide meaningful comments on the revised AFs. CSCME encourages CARB to take full advantage of this opportunity.

[The commenter attached Attachment 1, the June 2016 comment letter to ARB referred to in the preceding footnote. This attachment and other attachments are described further in 45-day comment B-6.10. The commenter also attached Attachment 2, a Public Records Act request from King & Spalding LLP to ARB, requesting all ARB correspondence regarding the Fowlie et al. and Gray et al. leakage studies commissioned by ARB.] (CSCME)

Response: With respect to the commenters' concerns with the rulemaking process, see response to 45-day comment M-1.1. Regarding comments on revised assistance factors, see response to 45-day comment M-1.4. Regarding the assertion that ARB has failed to respond to CSCME's September 14, 2016 Public Records Act request, ARB has, in fact, since responded to this request.

M-1.6. Multiple Comments:

JUG members suggest that additional opportunities for public input and discussions with all relevant agencies on this issue [EIM dispatch and emissions] should be held after the

⁵⁴¹ In its June 10, 2016 Comments on the Public Workshop on Emissions Leakage Potential Studies and in discussions with CARB, CSCME expressed significant concerns and requested additional data relating to the international market transfer rate and other data necessary to fully understand the leakage studies and the implications for the cement industry. See **Attachment 1**. On September 14, 2016, CSCME filed a request for information from CARB under the California Public Records Act. See **Attachment 2**. Thus far, CARB has not provided any data or information in response to these requests.

first Board hearing of these amendments and before the release of 15-day language. (JOINTUTILITIES)

Comment:

The ISO encourages ARB to schedule an additional workshop to discuss alternative approaches and obtain input from stakeholders...

The ISO supports ARB's effort to examine an appropriate means to account for emissions associated with EIM transfers. However, the ISO believes the proposed amendments to ARB's cap and trade and mandatory greenhouse gas reporting requirements present certain problems and require additional consideration. For these reasons, the ISO encourages ARB to continue its discussions with the ISO and stakeholders regarding this matter. (CAISO)

Comment:

In Portland General Electric's (PGE) view, ARB's other proposals impacting EIM in the Regulation are premature and need to be carefully realigned to sync with CAISO's timeline for implementing changes to their EIM GHG accounting framework. CAISO is just now beginning to work with stakeholders, including regulators and representatives from multiple states in the western interconnect, as well as CAISO's Market Surveillance Committee, on issues related to GHG accounting in both the current EIM and in the context of a multistate Regional ISO. CAISO and its stakeholders are aware that many of the same GHG accounting issues that have arisen in the EIM will also need to be resolved for a Regional ISO and have accepted that the process to develop a sustainable program that fits with both markets will take time. (PORTLANDGENELEC)

Comment:

LADWP believes that this issue has not been fully considered by CAISO, and stakeholder engagement has been limited given the short timeframe and relatively brief statement of reasons related to ARB staff's proposal. Unlike many other issues, there is no deadline for addressing emissions associated with secondary dispatch. Given the high cost of disruption of the regional electric-market integration process, ARB staff should not rush through this rulemaking and should provide sufficient opportunity for ARB, CAISO and stakeholders to understand and more fully analyze the problem and proposed solutions. (LADWP)

Comment:

Electricity Sector

We encourage ARB to continue working closely with CAISO to ensure the Energy Imbalance Market's cost optimization model fully accounts for the emissions associated with electricity generated to serve California load (NRDC)

Comment:

MID opposes including changes related to EIM secondary dispatch emissions into the Proposed Regulation Order. MID recommends that ARB take additional time to consider the problem of secondary dispatch in the EIM market, potential solutions (or whether a solution is warranted at all, and any market ramifications that action on this issue may illicit. The western energy markets are nearing a transformational change should the California Independent System Operator (CAISO) balancing authority area expand to include load in five other states. While the quantity of secondary dispatch emissions (a figure that has not yet been published) may be small, when applied to the regional scale day-ahead markets its impact may be monumental. Caution is urged to ensure that California ratepayers do not pick up the tab for other states' greenhouse gas emissions. MID recommends that ARB staff strike the amendments tying California entities to secondary dispatch compliance obligations at this time and that ARB continue to work closely with the CAISO and stakeholders to further evaluate EIM secondary dispatch. (MODESTOID)

Comment:

Program changes to address GHG emission tracking associated with the California Independent System Operator (CAISO) Energy Imbalance Market (EIM) should not be implemented until sufficient data is available to verify the magnitude of the potential issue and assess the corresponding impacts of proposed changes to the Program...

The Proposed Amendments contemplate several changes to the Cap-and-Trade Program that are intended to address concerns with inaccurate accounting of emissions associated with transactions in the CAISO EIM. Staff has identified concerns that the EIM optimization model may not account for all GHG emissions “experienced by the atmosphere as a consequence of electricity consumed in California.” The Staff Report describes the proposed changes as follows:

“To address these inconsistencies and ensure the Cap-and-Trade Regulation reflects the requirements of AB 32, ARB staff proposes to retain the current point of compliance of the CAISO participating resource scheduling coordinator, but to supplement that compliance obligation with a compliance obligation on entities that purchase from EIM (“EIM purchasers”) to serve load in California. The total supplemental compliance obligation for all EIM purchasers would be calculated based on the annual metric tons of CO₂e from electricity that is experienced by the atmosphere to serve California load through CAISO’s EIM, but not otherwise accounted for by emissions reported by the EIM participating resource scheduling coordinators. Each EIM purchaser’s compliance obligation will be calculated as the ratio of their EIM purchases (MWh-basis) to total EIM load to serve California (also measured in MWh). This accounting would ensure that the

full emissions associated with serving California are accounted for, and attributed entirely to entities that are engaged in serving California load.” (Staff Report p. 52)⁵⁴²

Since this issue was first raised by CARB staff during the February 24, 2016 Workshop, there have been several meetings with CARB and CAISO staff, as well as a workshop specific to this issue on June 24, 2016. During these meetings and workshops, CARB staff and CAISO staff presented information explaining the potential leakage concerns CARB raised. While CARB is currently working on analysis to quantify the emissions from EIM transactions that may not be accounted for, the analysis is not yet available for stakeholder review. At the same time, the CAISO has also provided additional information and analysis that looks at the totality of the EIM GHG emission impacts. The information provided to date on this issue is not entirely reconcilable, and the various proposals that CARB and CAISO presented during past workshops to address the issue may not actually do so. While CARB’s final quantification is still forthcoming, the CAISO preliminary results demonstrate that “EIM dispatch reduced GHG emissions by 291,998 M Tons for period January-June 2016.”⁵⁴³ Certainly, the totality of the impacts must be measured and the differences between the data assessment being conducted by CARB and the CAISO must be reconciled in order for stakeholders to have a meaningful opportunity to assess the magnitude of the issue and whether the proposed Program changes are either necessary or sufficient.

NCPA believes that it is important for CARB to ensure that GHG emissions associated with EIM transactions are accurately tracked and accounted for. However, given the current level of uncertainty regarding the appropriate measure for tracking these emissions, the lack of a definitive quantification of the emissions at issue, and the importance of ensuring that any actions taken relevant to the EIM are properly considered in the context of the potential regional CAISO, it is premature to make any regulatory amendments relevant to EIM transactions at this time. Furthermore, in light of the significance that any proposed amendments would have, this issue should be deferred to a new Rulemaking, rather than addressed solely through 15-Day changes...

Similarly, while CARB’s primary focus is on accounting for GHG emissions associated with electricity that serves California load, that accountability is not compromised by Cap-and-Trade program provisions designed to acknowledge the importance of California’s market structure, including programs that are designed to ensure the most efficient electricity dispatches under the EIM. In both of these instances, NCPA believes that CARB and its sister agencies must collaborate to ensure that there is accurate accounting for GHG emissions generated in the state and imported into

⁵⁴² The Proposed Amendments go on to define the “Energy Imbalance Market Purchaser” as one who holds the compliance obligation, pursuant to section 95852(b)(1)(b), for emissions not fully accounted for by CAISO’s EIM cost optimization model. (Section 95802(a))

⁵⁴³ Energy Imbalance Market GHG Counter-Factual Comparison (Preliminary Results: January-June 2016), dated August 25, 2016, p. 5. http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparisonPreliminaryResults_Jan-Jun_2016_.pdf

California as mandated by H&S Section 38530(b)(2), without impeding the reliable operation of California's electricity markets. (NCPA)

Comment:

BPA is federal power marketing administration that markets wholesale power from the Federal Columbia River Power System (FCRPS), which consists of 31 federal hydroelectric projects, one nuclear plant, and some other small nonfederal power plants. BPA also owns and operates about three-fourths of the Pacific Northwest's high-voltage transmission system and has interregional transmission lines connecting to California. BPA is statutorily-required to serve over 130 preference customers, some of whom reside within the California Independent System Operator (CAISO) Energy Imbalance Market (EIM) footprint. BPA is registered with the ARB as an Asset Controlling Supplier, and BPA sells FCRPS surplus power in the Northwest wholesale market and to the CAISO. Given all these aspects of BPA's business, changes to the EIM and the possible expansion of the CAISO will have broad impacts on BPA rate payers.

BPA appreciates that ARB is proposing to address the issue of emissions leakage resulting from the CAISO EIM cost optimization algorithm. BPA supports the accurate reporting of greenhouse gases and recognizes that the EIM algorithm likely needs to be reviewed and improved to better differentiate base schedules from incremental EIM dispatch signals and compliance obligations. Given the complexities of the leakage issue, BPA recommends that the ARB and CAISO jointly develop a long-term solution that will resolve the flaws already identified by the CAISO and ARB in the EIM algorithm, with the goal being to accurately assign GHG compliance to EIM participants and equitably treat the GHG compliance obligation between the EIM and CAISO market participants. A single coordinated process to further explore the issue with a unified statement of the problem can better assure that the ISO is properly solving ARB's concerns in a manner that the ISO is able to timely implement. (BPA)

Comment:

It would be in the best interest of all stakeholders involved to more fully understand the extent of this perceived problem, since remedying this concern will have significant implications. At this time, it does not appear that there is adequate understanding of either the problem or the solution. We believe that more robust inter-agency evaluation (based upon a more comprehensive set of data) and *meaningful* stakeholder engagement are necessary to fully understand the issue and the magnitude of the impact, as well as the realm of possible solutions and the resulting impacts. Of all the topics discussed prior to the formal rulemaking notice, this EIM issue received the least amount of lead time prior to its inclusion.

SCPPA therefore urges ARB to defer proposed changes to the reporting requirements until such time as the problem (if any exists) is fully understood, CAISO has completed its stakeholder engagement process on the matter, and the state agencies have

reached an agreement with stakeholder concurrence. Otherwise, we fear the hurried ARB regulations now may only serve to capture short-term Cap-and-Trade Program gains (which could possibly deter imports into California that are necessary to meet the state's RPS requirements), while undermining long-term emissions reductions initiatives across the West. This is one issue that does not have an immediate looming deadline, so it would be beneficial to take a few steps back to re-evaluate.

We believe it is also critical that each affected state agency have an equal voice in matters that directly impact their primary mission. It is imperative to recognize that California is part of the broader western electricity grid, and that any actions taken in our state may impact the larger regional market. Without a fix, any potential EIM benefits will be eviscerated by ARB carbon cost compliance obligation accounting; the consequence of which may be to *deter* new participant interest in, or even *undermine* existing participation within a flourishing market that has been widely touted by state energy officials, while burdening California ratepayers with the entirety of any accounting system for a broader market that they may not even benefit from. Further magnifying the need for inter-agency coordination is the fact that we (as a state) have yet to thoroughly explore how these GHG emission accounting efforts may translate to a broader, regionally integrated market as the Governor has sought to advance in the CAISO grid regionalization effort. The GHG accounting issue has proven to be an extremely contentious one amongst neighboring states in regionalization discussions. (SCCPA)

Comment:

Rather than the proposed regulatory amendments, WPTF believes that further work is needed by both CARB and the ISO, along with stakeholders, to develop modifications to how the EIM algorithm treats carbon costs in the dispatch and allocation of generation to serve CAISO load. (WPTF)

Comment:

As part of its proposed amendments, the California Air Resources Board ("ARB") is proposing to modify how it accounts for greenhouse gas emissions that are imported into California via the energy imbalance market ("EIM"). With respect to these proposals, PacifiCorp's central interest is in preserving the value and integrity of the EIM while also respecting California's environmental objectives. As they are currently proposed, the amendments to the Cap-and-Trade Program and MRR have the potential to negatively impact the EIM, including emissions reductions currently being achieved. Moreover, the current proposal is unlikely to solve issues raised by ARB regarding the existing methodology for identifying emissions associated with electricity imported to California via the EIM. To more effectively achieve California's overall environmental and energy policy objectives, PacifiCorp recommends that these complex issues be resolved as part of a joint inter-agency effort between ARB and the California Independent System Operator ("CAISO"). ARB's accounting for emissions associated

with electricity imports is unavoidably intertwined with the CAISO methodology for identifying those electricity imports. The CAISO methodology for identifying emissions and the associated regulation and accounting by ARB should be developed and/or modified at the same time. ARB's current proposal is made in the absence of a clear proposal from the CAISO as to any potential changes to the existing methodology. In light of potential negative impacts to the EIM and a future multistate Regional Independent System Operator ("RSO"), accounting for emissions associated EIM imports must be much more carefully considered before the adoption of any proposed amendments.

While ARB's amendments are pending, the CAISO recently announced a new stakeholder initiative called Regional Integration California Greenhouse Gas Compliance. This initiative will determine how greenhouse gas costs for supply resources outside of California will be treated in the CAISO's integrated forward market covering an expanded multi-state balancing authority area. In the issue paper for the RSO initiative, the CAISO acknowledges the connection between greenhouse gas treatment in the EIM and the RSO, noting that it is currently working with ARB and stakeholders to address concerns that the EIM greenhouse gas market design is not capturing the impact on the atmosphere that occurs in connection with EIM transfers into the CAISO to serve CAISO load. The paper states, "Resolution of those concerns may inform how to address similar concerns in connection with a day-ahead [greenhouse gas] market design." As noted above, these complex issues should be addressed jointly by CAISO and ARB to ensure the harmonization of energy and environmental policies and to avoid both economic inefficiencies and emissions leakage. (PACIFICORP)

Comment:

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. (PG&E)

Comment:

CARB's GHG Proposal is Premature

The EIM Entities believe that CARB's GHG Proposal is premature, as the ISO has not issued, and CARB has not considered, a revised proposed methodology for allocating

EIM GHG compliance costs to EIM entities. Any changes to CARB's regulations should be done simultaneously with any proposed changes to EIM operations. In addition, CARB's GHG Proposal is not clear with respect to how the changes will be implemented. (EIMENTITIES)

Comment:

ARB should postpone the CAISO EIM GHG accounting proposal in this regulation order until stakeholders have more time to analyze potential market impacts and offsetting effects. A recent focus on 'secondary emission effects' that result from the California Independent System Operator (CAISO) EIM optimization has led the ARB to propose a solution that is one-sided. On August 26, CAISO released a study demonstrating that the EIM dispatch actually displaced emitting generation for a net benefit to the atmosphere in the first half of 2016. In light of this information, Southern California Edison and JUG members do not support the current method proposed in the regulation for addressing the secondary emissions issue, as it would not take into account the emission reductions attributable to renewable exports. SCE agrees with JUG members in suggesting that additional opportunities for public input and discussions with all relevant agencies on this issue should be held after the first Board hearing of these amendments and before the release of 15-day language. ARB's proposal could set a precedent for future market expansion that could erode the environmental and cost benefits of that very expansion. (SOCALEDISON)

Response: Commenters express concern with the timing of the proposed amendments, as well as requesting additional time for discussions. With respect to concerns of the rulemaking process, please see response to 45-day comment M-1.1. Moreover, and based on input from CAISO and stakeholders during this rulemaking, ARB developed an EIM bridge solution in the Proposed Amendments (see first and second 15-day amendments package). The calculation under ARB's bridge solution, which identifies emissions resulting from California load not being accounted for in the current EIM deeming methodology, reasonably and conservatively captures GHG emissions from EIM market operations. The Proposed Amendments establish the calculation and retirement of allowances equivalent to EIM Outstanding Emissions from the pool of unsold allowances. When summed with the retirement of allowances for emissions reported by the EIM Participating Resource Scheduling Coordinators, this retirement is sufficient to account for California's EIM imports. Stakeholders have had an opportunity to comment on the proposed revisions to the Cap-and-Trade Regulation that effectuate this change. ARB may revise this methodology in a future rulemaking, depending on revisions to the EIM algorithm and as needed.

M-1.7. Comment:

SCPPA requests that the CPP provisions in their entirety be available for comment and possible modification under any 15 day amendment package. (SCPPA)

Response: ARB included its proposed Clean Power Plan provisions in the initial 45-day Proposed Amendments, thereby providing 45 days for stakeholder comment. These provisions were not subsequently revised in any 15-day amendment package. The CPP amendments, in any event, are designed so that they will only be implemented for regulated entities if the U.S. EPA approves them as part of a CPP compliance plan.

M-1.8. Comment:

Amendments to Implement the Backstop Measure for the State Plan for Compliance with the Environmental Protection Agency Clean Power Plan Should be Given Further Consideration Before Adoption.

Demonstrating California's compliance with the mandates of the Clean Power Plan, should it be approved and implemented, must be done in the manner that provides the greatest flexibility to affected electric generating units (EGUs) subject to the CPP mandates, while avoiding Federal jurisdiction over California's existing climate change policies and programs to the greatest extent possible. A "state measures" approach that utilizes the Cap-and-Trade Program is the logical and reasonable mechanism by which to do so.

NCPA supports this approach, despite the need to alter certain core provisions of California's existing Program. For example, while NCPA believes that the current three-year compliance periods best meet the needs of the State's compliance entities, transitioning the entire program to two-year compliance periods beginning in 2028 to comport with the CPP requirements is far more preferable than adopting separate compliance periods for affected EGUs only or even for the entire electricity sector. NCPA also supports the proposal to invoke this change only if the CPP State Plan is approved by January 1, 2019. However, NCPA believes that the specific provisions regarding implementation of the backstop measures require further assessment prior to adoption.

NCPA asks that the Board direct staff to provide more time for stakeholders to assess the implications of the backstop measure by flagging this issue as one that may be further modified in 15-day changes. Allowing stakeholders additional time to work through the proposal does not compromise the state's objective of moving forward with CPP implementation as soon as possible. Additional time, however, does provide California stakeholders with the opportunity to take more time to assess the backstop measure, including conducting further analysis on the impacts that triggering the backstop will have on affected EGUs that are also compliance entities under the Program. The backstop measure must be subject to further deliberations and

clarification before being finalized; no matter how remote the possibility is that the backstop will be triggered, because the possibility exists, it is imperative that sufficient analysis has been done. (NCPA)

Response: ARB included its proposed Clean Power Plan provisions in the initial 45-day Proposed Amendments, thereby providing 45 days for stakeholder comment. These provisions, including the backstop measure, were not subsequently revised in any 15-day amendment package. The backstop must bring affected EGU smokestack emissions into compliance with the federal standard if the combination of the “state measure” (the economy-wide market) and related emission standard (the requirement that EGUs participate in that market) does not perform as expected when compared to a glide path established by the state that is consistent with the federal targets. ARB believes that it has sufficiently analyzed the impact of the backstop measure. The CPP amendments, in any event, are designed so that they will only be implemented for regulated entities if the U.S. EPA approves them as part of a CPP compliance plan.

M-1.9. Comment:

Finally, given the complexity of these issues and the need to find a solution that is equitable for all LSEs, WPTF strongly encourages CARB to hold a dedicated workshop on the appropriate mechanism to compensate LSEs for costs incurred by the elimination of the RPS adjustment. If CARB cannot develop a solution to compensate for elimination of the RPS adjustment that is equitable across all LSEs, then ARB should not pursue it. (WPTF)

Response: In response to stakeholder comments, in the first 15-day amendment package, ARB decided to retain the RPS adjustment post-2020. All stakeholders had an opportunity to comment on this proposal.

M-1.10. Comment:

EDU Allocations: Allowance allocation is a key component to ensuring the costs of the Cap-and-Trade program are contained. It is fundamental to the structure and cost of the regulation, and establishes the market rules by which all parties must participate. It is of critical importance for Electrical Distribution Utilities (EDUs) that the proposed package contains the following language:

“Staff may propose post-2020 allocation as part of this rulemaking process. Any change proposed will be circulated for a 15-day public comment period.”

California EDUS have not been provided the opportunity to review and comment on an actual EDU allowance allocation for post-2020 prior to the Board’s initial public hearing, but the language implies that such a proposal may not be made during this regulatory process. SCPPA recognizes that this issue is complicated given the diversity and number of EDUs in the state, the number of other entities seeking allowance value, and

that SCPPA is actively participating with ARB and other EDUs in a process moving forward. However, SCPPA is extremely uncomfortable with such a central piece of the policy puzzle not being sorted out before the Board provides input and direction to staff. The ripple effects of EDU allocation will be felt by consumers throughout the state and, depending on the final proposal, could impact how other aspects of the proposed regulation operate. (SCPPA)

Response: ARB proposed a specific allowance allocation for each EDU for the 2021-2030 period in the 2nd 15-day amendment package. All stakeholders had an opportunity to comment on this proposal. See also response to 45-day comment M-1.1.

M-1.11. Multiple Comments:

1. CARB should provide much more than the minimum 15-day notice period for any changes in assistance factors. In particular, Air Liquide objects to CARB's proposal to announce the assistance factor applicable to industrial gas manufacturing sectors in a later regulatory amendment with a 15-day comment period...

In CARB's August 2, 2016 draft Regulation, CARB does not provide new assistance factors for any industrial sectors but state that it "may provide industry specific [assistance factors] in a 15-day comment period but instead intends to provide more notice and opportunity for public comment. But to the extent that CARB may intend to provide only a 15-day notice period, Air Liquide does not believe that such a comment period is adequate for affected industries to analyze or comment on a change in assistance factors. A change in assistance factors may have a dramatic impact on the economics of an entire industry sector, and should not be undertaken without an adequate period for analysis and fully informed public comment. By law, an agency may amend proposed regulations after the 45-day comment period has passed only where the change is "(1) nonsubstantial or solely grammatical in nature, or (2) sufficiently related to the original text that the public was adequately placed on notice that the change would result from the originally proposed regulatory action." Calif. Gov't Code § 11346.8(c). The 15-day process should be used to respond to comments made during the public comment period or during public hearings, not to define major elements of the regulation. A new or revised assistance factor would certainly not be "nonsubstantial," nor is it "sufficiently related" to the placeholder text provided in the current draft to provide notice to stakeholders as to what assistance factor CARB would ultimately promulgate. Air Liquide and other stakeholders will require more than 15 days to adequately review a proposed assistance factor.

CARB has indicated that any revised assistance factors proposed as part of a 15-day comment period will be implemented in the fourth compliance period (post-2020), rather than the third compliance period (post-2018), as the agency had initially intended. (Initial Statement of Reasons, Appendix E, at 2.) Given the extended timeframe, there is no

compelling reason for CARB to rush to revise assistance factors without an extended public comment period...

In the draft Regulation, CARB proposes changes to the product-based benchmarks only for certain industrial sectors, and not for the hydrogen production sector, but notes that it will be developing revised benchmarks for all sectors in future rulemakings. When CARB does propose changes to the benchmarks applicable to the industrial gas manufacturing sector, it is critical that CARB provide Air Liquide and other industrial gas manufacturing stakeholders an extended review and comment period. To reach a decision on the current benchmark, CARB worked with Air Liquide and other stakeholders for many months before the final benchmark was promulgated. For any future change in the benchmark applicable to the industrial gas manufacturing sector, regulated parties will need more than 15 or 45 days to analyze the data on which a proposed change is based and provide meaningful comments and suggested revisions to CARB. (AIRLIQUIDE)

Comment:

Comment Period for Post 2020 Industry Assistance Factors: Staff is proposing a 15 day comment period for changes to the draft regulation. This will not be sufficient time for regulated entities to evaluate data for their sectors. The Board should allow at least 45 days for comments on proposed changes, particularly for post-2020 assistance factors. (SOLARTURBINES)

Comment:

Industry Assistance Detail Lacking

AB 32 required the ARB seek to limit leakage of emissions out of California in its implementation of GHG reduction regulations, including the market-based mechanism. As a part of the program, ARB initially allocated 100 percent (truly 90 percent when you figure in the 10 percent “haircut” ARB took for auction allowances) to ensure that the regulations did not incentivize the loss of emissions to other jurisdictions. ARB later extended the initial allowance allocation into the second compliance period to maintain leakage protection.

CMTA appreciates that ARB backed off an earlier plan to amend the allowance allocation in the Third Compliance Period (2018-2020) as this would have placed California manufacturers in a very awkward and challenging spot. However, it is troubling that ARB staff would propose such a massive to the Cap and Trade regulation without detail on the proposed change for the post-2020 plan with the exception to say in Table 8-3 that:

“[Staff may propose assistance factors as part of this rulemaking process. Any change proposed will be circulated for a 15-day public comment period.]”

CMTA believes that given the significant economic impact represented by the allowance allocation process demands a greater amount of time to provide the type of substantive analysis given millions of dollars and thousands of jobs at stake. Indicating that ARB staff may propose changes in a 15-day comment period could violate the spirit of the different comment period timeframes and call into question the legitimacy of the proposed change. The purpose of the 15-day comment period is to address minor changes and updates based on feedback received in 45-day comment period. The potential change to allowance allocation neither is minor, nor is in response to feedback that has yet to come into ARB on the proposed change. (CMTA)

Comment:

We'd also argue that the -- doing any further adjustments for a post-2020 industry assistance -- or assistance factor should be done in a 45-day comment period, and that to do so in a 15-day amendment that's intended to address minor changes, technical changes, respond to comments would be, I think, inappropriate in this setting, given the economic impact and the millions and millions of dollars at risk. (CMTA2)

Comment:

Industrial assistance is critical to maintaining the environmental integrity of the cap-and-trade program. In addition, protecting the jobs and economy is essential. While additional time is appreciated to discuss alternative methodologies for trade exposure, 15-day comment periods will not allow sufficient time for affected stakeholders to assess the impacts of the new assistance factors. (CALCHAMBERCOMMERCE)

Response: ARB included in the 45-Day Notice and the ISOR for this rulemaking a description of how this rulemaking would consider specific industry assistance factors, and that additional information was being discussed with stakeholders to be included in 15-day amendments. As such, ARB staff believes that it is authorized to propose specific industry assistance factors in a 15-day amendment package after noting its intent to do so in an initial 45-day amendment package. Regardless, in response to extensive stakeholder comments, ARB proposed to remove all post-2020 industry assistance factors in the second 15-day amendment package. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program. With respect to commenters' concerns with the comment periods in an APA rulemaking, please see response to 45-day comment M-1.1.

M-1.12. Comment:

There are a number of food processing industries that staff has yet to propose a new benchmark for, such as dairy manufacturing.

Recommendation: If ARB is going to change the dairy benchmarks, the industry needs advanced, and deeply involved, stakeholder input. In the ISOR, staff asserts that they have worked with the industry on changes that may be made to the dairy product manufacturing benchmark. We hope this is the case and would like to be informed of the entities staff is working with on a go-forward basis. (AGCOUNCIL)

Response: In response to extensive stakeholder comments, ARB proposed to remove all post-2020 industry assistance factors in the second 15-day amendment package. ARB intends to continue assessment of appropriate calculations of emissions leakage risk for the post-2020 period and to propose post-2020 assistance factors in a future rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

M-1.13. Multiple Comments:

Releasing data on trading and allowances is absolutely critical. And I would argue it is absolutely critical to addressing more accurately the questions that Senator Florez and Supervisor Serna were relating about the efficacy of the allowance -- the allowances in particular. While, yes, there are facility reporting on low emissions, we do not know how those facilities right now are meeting their emission requirements. They can be and the research is starting to show that they are offsetting the vast majority of those emission reductions. (CEJA2)

Comment:

By design, California's Cap-and-Trade Regulation denies public access to the details of greenhouse gas emission trades. This is an unprecedented and indefensible feature of California's climate program. For other pollutant trading programs, emission credits used by specific facilities are a matter of public record. (STROMBERG)

Response: These commenters seek greater access to information reported or disclosed under the Cap-and-Trade Regulation. ARB staff has not proposed changes to any public disclosure provisions of the regulation as part of this rulemaking, and as such, these comments are outside the scope of the Proposed Amendments. However, for a discussion of the large amount of data that is made publicly available for the greenhouse gas reported data and market compliance information, please see response to 45-day comment K-1.5. In addition, ARB staff discussed the level of public information that is made available as part of the program during the September Board hearing, and included a description of a

summary document describing the types of information that is already made publicly available as part of the Board item summary.⁵⁴⁴

M-1.14. Multiple Comments:

2. When announcing proposed changes to proposed assistance factors, CARB should provide the data and rationale supporting any such change so that affected industries may examine them and provide comments based on a full analysis of the relevant data...

It is also of key importance that CARB provide all of the data on which CARB bases any changes in assistance factors. CARB has provided substantial information in Appendix E to the draft Regulation, but to the extent that CARB relies on additional information in determining a proposed assistance factor, that information should be published for public comment. Stakeholders cannot meaningfully comment on a hypothetical change in an assistance factor without CARB's disclosure of that assistance factor and the information on which it is based. (AIRLIQUIDE)

Comment:

4.1 CARB's Proposed Approach Lacks Transparency & Accountability

CARB's proposed approach relies almost exclusively on the results of the leakage studies, which were conducted using confidential data from the U.S. Census Bureau that cannot be accessed, inspected, or verified by anyone other than the authors. Although this may be an acceptable practice for intellectual and academic pursuits, it is an inherently flawed basis for crafting public policies that can have profound consequences on manufacturing facilities, their employees, and the communities that they support.

The fundamental flaws of this approach are apparent in at least two respects.

- Given the confidential nature of the data, the regulated community has no ability to verify the accuracy of the underlying data, the analytical methods used, or the results. Consequently, CARB's proposed approach to addressing leakage rests in a "regulatory black box" that, by design, lacks transparency and effectively denies the regulated community any possibility of due process.
- Given that CARB has indicated that even its own staff does not have access to all of the data, the regulatory authority itself has no ability to verify the accuracy of the data, methods, or results. In short, CARB has abdicated its regulatory responsibilities and effectively outsourced them to unaccountable third parties.

⁵⁴⁴ See Transcript, ARB Board Hearing, September 22, 2016, at page 201, <https://www.arb.ca.gov/board/mt/2016/mt092216.pdf> (describing a "list of publicly available program information" that is available at https://www.arb.ca.gov/cc/capandtrade/public_info.pdf).

Although CSCME has many other concerns, as outlined below, we believe that the lack of transparency and accountability are fatal flaws that make CARB's proposed approach unsuitable for formulating policy and that place it on inherently unstable regulatory, legal, and policy grounds...

4.6 CARB's Proposed Approach is Unlikely to be Legally or Practically Durable

CARB's process for developing its revised methodology has been neither transparent nor independently verifiable, which is likely to undermine stakeholder confidence in the rulemaking process and erode the durability of CARB's proposed approach across policy and political cycles. Specifically, CARB has proposed to replace its existing metrics (greenhouse gas intensity and trade exposure), which are based on publicly available and verifiable data, with two new metrics ("domestic drop" and international market transfer), which are constructed using data that cannot be publicly accessed and a process that has not yet been replicated or verified. Indeed, by CARB's own admission, the studies that produced these metrics break new ground in existing research, which is all the more reason that regulated industries and independent third parties must be given the time and data necessary to replicate their results and stress test key conclusions according to a range of assumptions and model specifications. Without providing adequate time and applying the appropriate level of analytical rigor and skepticism to verify untested research methods and methodologies, neither CARB nor regulated entities can have confidence in the durability of the revised leakage metrics or the associated assistance levels.

Moreover, in addition to regulating California industries according to a policy framework and metrics that they are unable to fully understand, evaluate, or vet, CARB's revised approach would also lock industries into a leakage classification system that cannot be updated without commissioning new studies. Such an approach to providing leakage assistance is inherently unstable and bound to generate skepticism among regulated industries, because it precludes the timely integration of new data and information as they become available and because it is subject to the particular assumptions and unique modeling choices of the individual authors and researchers producing the studies. (CSCME)

Response: In response to extensive stakeholder comments, ARB proposed to remove all post-2020 industry assistance factors in the second 15-day amendment package. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

M-1.15. Comment:

The methodology ARB adopts to determine the number of allowances that will be allocated to each EDU will significantly impact ratepayers. LADWP supports ARB's

proposal to base its methodology primarily on expectations of each EDU's cost burden (cost-based allocation methodology)....

It should be noted, however, that substantial uncertainty remains with regard to the proposed allocation approach. ARB has not spelled out, in detail, its proposed methodology and has left blank important components of this piece of the post-2020 program, including the utility-specific allocations for 2021-2026 and the details of the methodology for 2026 and beyond. LADWP will provide additional comments once ARB has further developed its proposal and urges ARB to provide affected utilities sufficient time to analyze and submit comments on those proposed new elements (including their interrelationship with the entire Cap-and-Trade Regulation) once that proposal has been released for public comment...

ARB Should Allocate Allowances Through 2030 and Post-2020 Allocations Should be Based on One Consistent Methodology That Takes the Ratepayer Cost Burden Into Account

ARB has proposed that each EDU's post-2020 allocation will be a set number of allowances for each year of 2021-2026, and that "staff may propose a methodology as part of this rulemaking process" for "Allocation in 2027 and Beyond."⁵⁴⁵ ARB has not proposed the specific allocation numbers for 2021-2026,⁵⁴⁶ nor has it provided any details on the methodology it would use to allocate allowances in the subsequent years (i.e., 2027 and beyond).

LADWP appreciates that ARB intends to specify the number of allowances that will be allocated in 2021-2026 as part of the rulemaking process for post-2020 allocation. It is our understanding that ARB would not provide similar individual EGU allowance allocations for the 2027 to 2030 period, but would provide a formula or cap adjustment for EDUs to apply to calculate their allowance allocations. LADWP looks forward to providing comments once these specific numbers-and more detail on the underlying methodology-have been proposed. LADWP urges ARB staff to provide specific information on its methodology to calculate the EDU-specific allocation numbers, such as through a publicly available spreadsheet. (LADWP)

Response: ARB proposed a specific allowance allocation for each EDU for the 2021-2030 period in the 2nd 15-day amendment package. All stakeholders had an opportunity to comment on this proposal. See also response to 45-day comment M-1.1 regarding the rulemaking process.

M-1.16. Multiple Comments:

Lack of Post-2020 Design Detail Impedes Stakeholder Input

⁵⁴⁵ 2016 ISOR, Appendix A at 208 (proposed § 95892(a)(2),(3)).

⁵⁴⁶ 2016 1SOR, Appendix A at 216-18 (proposed Table 9-4).

CCPC objects to the lack of critical regulatory detail regarding several 2030 design elements in the proposed regulation. There is no way to analyze the economic impacts of the proposed 2020-2030 cap due to the lack of information on trade exposure status, holding limits or other cost containment policies (besides APCR). (CCPC)

Comment:

LACK OF POST-2020 DESIGN DETAILS

There is a lack of critical detail surrounding several of the 2030 design elements in the proposed regulation. Given the lack of detail, this limits the input of stakeholders and also the scope of what the CARB can propose in subsequent 15-day packages. (CALCHAMBERCOMMERCE)

Comment:

CCEEB is concerned that it is difficult to analyze the economic impacts of the proposed amendments and the 2030 cap due to the lack of information on trade exposure status, holding limits or other cost containment policies (besides Allowance Price Containment Reserve (APCR)). Reports such as the Resources for the Future and University of California, Berkeley Employment and Output Leakage under California's Cap-and-Trade Program and Measuring Leakage Risk papers that are utilized to make decisions that have significant impacts on industry and the economy lack access to raw data and assumptions needed to ensure the conclusions they have reached are confirmable and plausible.

Stakeholder engagement has been difficult, almost impossible without the information on what the program will look like post-2020. The inability of stakeholders to analyze the potential impacts between 2020 and 2030 short changes our ability to provide meaningful feedback on the proposed cap. Simply stated, GHG emissions will be capped at roughly what the entire transportation sectors emissions are today. We encourage ARB to consider whether it is truly appropriate to set the cap based on the prior assumptions that 77% of the emissions will be under the cap in 2020. The assumption of 77% of the State's emissions when applied to the 2030 context may results in an unnecessarily stringent cap of 200.5 mln t/yr. Since the mix of covered entities and the amount of emissions will change over time and the new 2030 goal is very stringent, the rationale for the cap number should be more robust than simply that ARB applied the same percentage as in 2010's rulemaking. It is not clear why it is necessary to make the cap for Cap-and- Trade more stringent than the overall State goal of 256.6 mint/yr. (CCEEB)

Response: Stakeholders have had an opportunity to comment on the initial Proposed Amendments and the two sets of revisions to the Proposed Amendments. Any bracketed text indicating that a provision is subject to review and potential revision in the initial Proposed Amendments that was, in fact, amended was followed by a 15-day comment period for such proposed

amendment. ARB has fully complied with the APA in this rulemaking and stakeholders have had an adequate opportunity to comment on every proposed change that bears on the design of the Cap-and-Trade Program. ARB believes that it has clarified the most significant design features for the Program post-2020 and that its 2030 cap is adequately justified. See also response to 45-day comment M-1.1.

M-1.17. Comment:

Achieving our ambitious 2030 targets will require ARB to work with other agencies, jurisdictions, and program processes. Coordinate meetings between the interagency working groups (IWG) and EJAC, to encourage information sharing and mutual cooperation between the groups. (EJAC)

Response: This comment was submitted to the Cap-and-Trade Regulation rulemaking, but indicates it was part of the commenters' submittal to the ongoing 2017 Scoping Plan Update process. The comment does not request any specific changes to the Proposed Amendments and no further response is needed.

M-1.18. Comment:

Improve coordination among state, federal, and local agencies with regard to their planning and implementation activities. Support cities and local implementation of Energy and Climate Action Plans...

c. Better coordinate climate pollution and local criteria pollutants programs. (EJAC)

Response: This comment is outside the scope of the Proposed Amendments.

M-1.19. Multiple Comments:

Reducing Emissions Throughout California's State Agencies

California's other regulations and purchasing programs should reflect the state's priority in reducing emissions. This commitment to addressing climate change is not occurring across all state agencies and local public entities as it should.

For example, just last year, a local school district chose to buy tens of thousands of dollars of cheaper food imports sourced from over 6,000 miles away. Meanwhile, several food processing facilities within a two-hour drive of the school district process the very same product. While the financial cost of the product may have been slightly less expensive, the environmental cost was not.

California farmers and the food processing industry are subject to numerous directives to purchase lower-emission tractors, forklifts and more fuel-efficient trucks, all of which come at a financial cost. All of these environmental benefits – as a result of investments by farmers and food producers – are more than negated when public agencies import products with a large GHG footprint. The state must not undermine its significant efforts to reduce GHGs by spending taxpayer dollars to import products from

nations not complying with equivalent emissions standards, not to mention food safety and other environmental standards. We urge ARB to engage with other state agencies to ensure that their practices are also reducing emissions, similar to private industry. (AGCOUNCIL)

Comment:

Key theme: Inter-agency coordination is necessary to ensure that policies seeking to reduce greenhouse gases from the electric sector are complementary and recognize existing precedent. With so many policies and programs guiding the electric sector towards a decarbonized future, it is necessary to ensure that agencies and the programs they administer work together. The differing focus at state agencies can result in myopic policy making that impacts utility efforts to achieve state goals at other agencies...

Additional cross-agency initiatives include the Integrated Resource Plans, the 50% RPS requirements, and utility requirements to develop transportation electrification proposals and bring them before the CPUC and POU Governing Boards. With utilities playing such a prominent role in the state's long term climate change strategy, it is imperative that state agencies work to create a synergistic regulatory environment. (JOINTUTILITIES)

Comment:

SMUD also supports the comments filed by the Joint Utility Group, covering the following key themes:...

- Inter-agency coordination is necessary to ensure that policies seeking to reduce greenhouse gases from the electric sector are complementary.

(SMUD)

M-1.20. Comment:

Oh, an overarching issue that we would like to address is the notion of interagency coordination. Not necessarily sitting down in every single workshop or meeting between various agencies, but the extent to which actions and implementation of the Cap-and-Trade Program, for example, impact entities that have to comply with the RPS, program mandates, or the way they impact electricity markets in general with regard to issues such as changes to address the EIM. (NCPA2)

Response: These comments do not seek any specific modifications to the Proposed Amendments, and are outside the scope of the Proposed Amendments. Regardless, ARB notes that it coordinates with other state agencies, to the extent required by law, as identified in the proposed 2017 Scoping Plan Update and subsequent updates, and as further needed to achieve GHG emissions reductions towards achieving the State's climate goals.

M-1.21. Comment:

Furthermore, incorporation of the CPP into the Cap-and-Trade program also necessitates a review of the manner in which imported electricity is counted to ensure that California entities are not paying twice for the same compliance obligation. NCPA believes that the Cap-and-Trade regulation can be amended to address this issue without compromising the integrity of the California program and in a manner consistent with the requirements of AB 32. As long as imported electricity is accounted for, there is no conflict with AB 32. The manner in which imports are accounted for will also be impacted by the EIM and potentially expanded CAISO, and NCPA appreciates that CARB is already working with the CAISO on this matter. NCPA encourages CARB to expand these discussions to include all of the State's balancing authorities (BAs) and not just the CAISO, as these other BAs will also be affected by the changed market dynamics and related impacts. (NCPA)

Response: ARB will coordinate with other balancing authorities as necessary. Note that the CPP amendments, in any event, are designed so that they will only be implemented for regulated entities if the U.S. EPA approves them as part of a CPP compliance plan.

M-1.22. Comment:

Ensure that AB 32 economic reviewers come from various areas around the state to represent insights on economic challenges and opportunities from those regions. The Environmental Justice Advisory Committee must choose at least half of the members. Ensure that the EJAC receives ready and timely notice of and access to any economic reviews, in time to give advice to and guide the process. (EJAC)

Response: This comment refers to a broader economic review request of the proposed 2017 Scoping Plan Update, and is outside the scope of the Proposed Amendments.

M-1.23. Multiple Comments:Appendix F

The regulations and implementation of the provisions of California's greenhouse gas policies will have significant impact on businesses within the state, particularly those in the industrial sector that are directly affected by a mandate to report GHG emissions levels or participate in the cap-and-trade program. As such it is important that the early and sustained input from a representative group of industrial entities be a part of ARB's process to develop regulations in this area. ARB must take the step to establish an "Industrial Advisory Council" (IAC) to meet on a regular basis to evaluate and provide feedback to ARB staff during the regulatory development process in this formal capacity.

The California Global Warming Solutions Act of 2006 (AB 32) directed ARB to form the Economic and Technical Advisory Committee to “to advise the state board on activities that will facilitate investment in and implementation of technological research and development opportunities.” In a similar fashion, the IAC would advise ARB regarding activities that will support industrial activity toward achieving California’s overall GHG reduction goals. Taking this step would improve the regulatory development process. (CCPC)

Comment:

We think will really help improve everybody to work on a more collaborative basis is that we would encourage ARB and staff to establish an industrial advisory council very similar to the environmental advisory council to meet on a regular basis to evaluate and provide feedback to ARB staff during the regulatory development process in a formal capacity. That way us, you know, regulated communities would be able to come in and speak to staff members and provide more collaborative feedback, I think, on the rule-making. (CCPC2)

Response: The comments appear to recommend the creation of new advisory groups to afford industrial stakeholders another forum for discussing with ARB with respect to multiple regulations. Since these comments do not appear to specifically request changes to the Proposed Amendments, they are outside the scope of the Proposed Amendments. Regardless, ARB notes that stakeholders frequently seek meetings with ARB staff, and that ARB considers and responds to all stakeholder comments on any rulemaking. Therefore, the input of industrial entities is always considered, regardless of the formulation of an advisory committee.

M-1.24. Comment:

Otherwise, new technologies going into the post-2020 are going to be absolutely key in terms of making this a successful program. And we're going to need the types of investments that are going to be able to support us in that. And as I've said before, I think you should seriously think about bringing back ETAAC, the Economic and Technology Advancement Advisory Committee. That -- with the Board's heft and weight behind that, you can direct that committee to be really focused on developing new technologies that will help us to be able to reduce our emissions directly.

And I think that also complies with 197, because if we had new development in technology, we would be able to have those types of direct emission reductions associated with the facilities. So please, you know, really consider about ETAAC. (FOODPROCESSORS2)

Response: See response to 45-day comment M-1.23.

M-1.25. Comment:

Consider supplementing the Standardized Regulatory Impact Assessment with energy-economic modeling to more accurately assess the likely impacts of the proposed regulation...

Consider supplementing the Standardized Regulatory Impact Assessment with energy-economic modeling to accurately assess the impacts of the proposed regulation.

In its Revised Standardized Regulatory Impact Assessment (SRIA), ARB presents the results of economic modeling aimed at assessing the impacts of the program on California economic activity, employment, and other indices.⁵⁴⁷ This economic modeling estimates the costs of the program⁵⁴⁸ and compares it to other regulatory alternatives.⁵⁴⁹

Unfortunately, because the models employed to assess the program do not explicitly model the energy system in detail or even include greenhouse gas emissions⁵⁵⁰—two self-evidently important variables for a greenhouse gas cap-and-trade policy—ARB is forced to estimate the cost of the proposed program by relying on 2014 emissions data, multiplied by the Auction Reserve Price and the APCR trigger price.⁵⁵¹

We are concerned that this approach may not be representative of the likely performance of the proposed program. This is especially true given the much greater ambition of the program from 2020 to 2030 as compared to the pre-2020 program. However, without an integrated energy economic model to simulate the effects of the proposed regulation, there is no reliable means of estimating allowance prices necessary to achieve the targets. ARB's approach also renders comparison of alternative policies—direct regulation or a carbon fee—much less meaningful.

We note that California is home to research universities with a number of prominent economists who have simulated exactly these issues in the past for ARB—quite accurately predicting in advance that the odds pointed to over-allocation in the pre-2020 period.⁵⁵² We urge ARB to either rely on this existing expertise or find alternative experts, tasking their selected advisers with more accurately constraining the expected allowance price trajectory needed to achieve the SB 32's 2030 target and characterizing key uncertainties affecting allowance prices.

The best economic and energy systems analysis is critical to making good decisions about the path forward for California's climate policy. Marketbased climate policies, such as cap-and-trade, will be critical to achieving the deeper emission reductions

⁵⁴⁷ ISOR, Appendix C.

⁵⁴⁸ ISOR at ES-7; ISOR, Appendix C at 16-27.

⁵⁴⁹ ISOR at 325-328; ISOR, Appendix C at 27-31.

⁵⁵⁰ ISOR, Appendix C at 20 ("REMI is not an energy or emissions model, so it is not possible to estimate the emissions reductions that could be associated with a particular allowance price.").

⁵⁵¹ *Id.* at 18-19.

⁵⁵² See Borenstein et al. (2014), *supra* note 14 at 3; see also Borenstein et al. (2016), *supra* note 14 at 4.

required after 2020, and therefore it is all the more important that market design details are based on the highest quality technical analysis. Because the analysis presented in the SRIA and used to inform the ISOR does not actually simulate the emissions response of the covered sectors to a carbon price, ARB's efforts falls short of best practices and may have unintentionally produced misleading conclusions. We therefore urge ARB to conduct supplementary modeling efforts that estimate the dynamic response of the California economy to the imposition of the annual allowance budgets proposed in the ISOR.

Thank you again for the opportunity to comment on the proposed rule. We would be happy to discuss our comments further with ARB Board Members or Staff if there is any interest in doing so. (WARA)

Response: The comment does not request any change to the Proposed Amendments, and since the Standardized Regulatory Impact Assessment for the Proposed Amendments complies with the APA and with Department of Finance requirements, no further response is needed. The SRIA is required to estimate the costs of the proposed amendments; it is not designed to pick a carbon price as suggested by the commenter. The commenter is conflating the SRIA process with other modeling meant to understand the performance of carbon pricing to achieve a specific GHG emissions target.

M-1.26. Comment:

Further consideration is still needed to determine how new 2030 and beyond emissions reduction targets are technologically feasible, adequately demonstrated at a commercial level, and can be implemented in a cost-effective manner for California utility ratepayers. In addition, the emission reduction targets and policies must be implemented in a way that does not cause conflict with other local, state, and national environmental regulations (including federal energy reliability standards). SCPPA urges ARB to assess the full economic impact across options available for achieving the 2030 emissions reduction target on the California economy, California businesses, and individual ratepayers. As the suite of California's environmental and energy policies are intended to work together to reduce emissions, ARB should consider broader categories of cost impacts experienced by market participants as they are interlinked to the cost of compliance with the Cap-and-Trade program. ARB should also work with state agency partners to include a quantitative analysis of progress to date in terms of meeting emissions reduction targets. (SCPPA)

Response: ARB has assessed the economic impact of the Proposed Amendments in its Standardized Regulatory Impact Assessment, pursuant to APA and Department of Finance requirements. Moreover, the comment speaks to the general feasibility and costs of achieving the 2030 statewide GHG target. That evaluation is outside the scope of this rulemaking and more appropriately evaluated as part of the proposed 2017 Scoping Plan Update.

M-1.27. Comment:

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. (PG&E)

Response: ARB anticipates that the State Compliance Plan will ensure CPP compliance. ARB does not intend to conduct additional analysis before plan submittal to EPA.

M-1.28. Comment:

Also, while ARB's post-2030 annual cap-setting methodology seems reasonable at this time, the JUG believes that a review process should be put into place in the Scoping Plan Update to monitor program costs and feasibility going forward considering the large degree of uncertainty that exists when considering California's multi-decade effort to reduce greenhouse gases. A cap-setting methodology post-2030 has the benefits of allowing California to use the Cap and Trade program as the primary means of compliance with the Federal Clean Power Plan, and provides the opportunity to borrow from future years for the APCR. However, the regulation should include a process to monitor market performance and revisit market design choices in a program extension this far out into the future. (JOINTUTILITIES)

Response: ARB continually assesses the functionality of the Program and may make revisions to the post-2031 cap-setting methodology if needed. ARB has already made several adjustments to the Program through several sets of amendments since the initial adoption of the Cap-and-Trade Regulation. This process of monitoring and adjusting through a public process will continue to be part of ARB's process in implementing the Program. To the extent the comment seeks to include a review process in the proposed 2017 Scoping Plan Update, that comment is outside the scope of this rulemaking.

M-1.29. Comment:

ARB and other state agencies (including the California Public Utilities Commission, California Energy Commission, Office of Environmental Health Hazard Assessment, Department of Toxic Substances Control, and CalRecycle) must undertake a process to examine the growing evidence that biomass and biogenic carbon have real and significant climate impacts, examine the long-distance transport contribution to overall greenhouse gas impacts of burning biomass material, and examine assumptions of health and environmental impacts from burning various materials considered to be biomass, including the impacts of biomass ash. Ash from burning biomass, urban wood waste, and other materials has been found to be dumped on California agricultural land in recent years, and this ash has been found to be contaminated with dioxin and other health-threatening chemicals. Before pursuing increased burning of biomass in California, ARB, the Natural Resources Agency, and related agencies must investigate where ash from the existing burning of biomass is ultimately being dumped, the environmental justice impacts and impact on agriculture, and the cost of biomass ash handling in California. This is of growing importance as new EPA regulations allow for the increased burning of waste and biomass at industrial facilities (i.e. industrial boilers, cement kilns), and as material deemed to be biomass are exempt from compliance obligations under California's Cap and Trade program. (EJAC)

Response: ARB staff did not propose amendments to the biomass exemption. As such, this comment is outside the scope of the Proposed Amendments.

M-1.30. Comment:

Ensure that the Adaptive Management tool is adequate for real-time monitoring and intervention. There must be at least two EJAC members on the Adaptive Management work group. To demonstrate how the tool can help communities, complete an Adaptive Industry Management analysis for Kern County. (EJAC)

Response: The comment appears to refer to a process and a tool that are outside of the scope of the Proposed Amendments. As such, no further response is needed here.

M-1.31. Comment:

It's simply not sufficient to relegate the impacts of cap -- the disproportionate impacts of cap and trade to the adaptive management plan that is not set up to lead to direct program changes as a result of any disproportionate impacts that are highlighted. They're absolutely critical to the health of environmental justice communities. (CEJA2)

Response: See response to 45-day comments M-1.29 and K-1.9.

N. CLIMATE PROGRAMS AND SCOPING PLAN

N-1.1. Multiple Comments:

We don't feel it's appropriate to be giving cap-and-trade discussions before the scoping plan is complete, since the entire intent of this process is to determine how and if cap and trade would continue past 2020. (EJAC2)

Comment:

3.3 Concerns About the Sequencing of the Rulemaking Process

CARB has indicated that the 2030 Target Draft Scoping Plan will be considered by the Board in early 2017.⁵⁵³ According to CARB, the Plan will “serve as the framework to define the State’s climate change priorities for the next 15 years and beyond” and “chart the path to achieving the 2030 target and describe the potential role of a post-2020 Cap-and-Trade Program.”⁵⁵⁴

In the absence of guidance provided by the Scoping Plan and its associated analysis, any regulatory development for the post-2020 program is premature. By engaging in a highly complex and piecemeal regulatory process, CARB is not sending a clear “investment signal”⁵⁵⁵ but rather is making a presumption about the scope and methodology under the post-2020 framework, which is creating more uncertainty rather than less.

Accordingly, CSCME urges CARB to present a new regulatory package after the adoption of the final 2030 Target Scoping Plan that addresses all elements of the post-2020 allowance allocation framework as well as other aspects of the cap-and-trade program that must work together to satisfy the requirement under AB32 to minimize leakage. (CSCME)

Response: As the ISOR in this rulemaking indicates, the analysis of the Cap-and-Trade Program is considered in both the rulemaking as well as in the proposed 2017 Scoping Plan Update, and is consistent. Although comments regarding the proposed 2017 Scoping Plan Update are outside the scope of the Proposed Amendments, ARB staff notes that the proposed 2017 Scoping Plan Update includes several policies and measures, some of which are already required by statute. The proposed 2017 Scoping Plan Update does not promulgate the proposed policies and measures, and clearly states that such policies will be completed through separate public processes with their own detailed analyses. With respect to the requirements of the rulemaking process, please see responses to 45-day comments M-1.1 and M-1.4.

⁵⁵³ ISOR at E-2.

⁵⁵⁴ ISOR at E-2.

⁵⁵⁵ ISOR at E-2.

N-1.2. Multiple Comments:

The GHG Emission Cap For 2031-2050 Should be Informed by the Most Recently Available Scoping Plan Update and Data Available After 2021.

The Proposed Amendments set the 2021 to 2031 allowance budget for the Cap-and-Trade Program. (Section 95841(a), Table 6-2)⁵⁵⁶ Establishing the allowance budget for this time period is important to provide market certainty for the Program and to ensure access to potential future allowances should it be necessary to invoke those cost containment provisions at a later time. While the Proposed Amendments properly acknowledge that the Program will extend beyond 2031, establishing the GHG emission cap for 2032 to 2050 is premature at this time. The Staff Report recommends an approach for setting a formula for the post-2030 cap that reflects the expected 2050 Program emission cap, and the 80% share of that cap expected to come from the Cap-and-Trade Program. (Staff Report, p. 12) However, as the Staff Report also notes, the Scoping Plan is required to be updated every five years, and significant changes in programs and technologies are not only possible, but probable between now and 2030. For this reason, the Proposed Amendments should not include a specific formula for the post-2031 emissions cap that includes a cap decrease established at this time. Rather, CARB should address the proper modeling for establishing the 2032 to 2050 cap in a future rulemaking, and exclude the equation for setting the GHG allowance budgets for years 2032 to 2050 proposed in section 95841(b) in this rulemaking.

The current Scoping Plan Update is intended to look through to 2030. A future update may include additional programs or measures. Future updates will also include a review of the impacts and reductions from other plans and measures, which may change over time. Assessing the appropriate post-2031 cap for the Cap-and-Trade Program should be done after there has been an updated Scoping Plan analysis of the GHG reductions resulting from other State programs and measures in order to ensure that it reflects the most recent data and information available at that time. (NCPA)

Comment:

We support the use of the Cap-and-Trade Program for CPP implementation. But cap setting, we believe that it is premature to include any kind of calculation for what the 2030 cap should be. We think that instead we should wait and see what some of the scoping plan results are from scoping plans that are developed between now and the time that we need to set the post-2030 cap. (NCPA2)

Response: See response to 45-day comment N-1.1 regarding the relationship between this rulemaking and the separate, ongoing 2017 Scoping Plan Update

⁵⁵⁶ The Staff Report - ISOR and Proposed Amendments in Appendix A are not entirely consistent in the manner in which the two documents refer to the future budget periods. The Staff Report-ISOR refers to the 2031 to 2050 (pp. 12-13) period, while the Proposed Amendments refer to the period 2032 to 2050. NCPA assumes that the correct periods are 2021 to 2031 and 2032 to 2050, as this comports with the established compliance periods defined in Section 95840 of the Proposed Amendments.

process. In addition, Appendix C of the ISOR for this rulemaking indicated that the proposed amendments is expected to provide reductions in the range of 100 to 200 MMTCO_{2e} from 2021-2030. The proposed 2017 Scoping Plan Update supports this range, finding expected reductions would be 179 MMTCO_{2e}. With respect to the comment regarding post-2020 and post-2030 cap setting, see responses to 45-day comments H-5.3, H-5.5, and H-5.6.

N-1.3. Comment:

Emission Reductions and Relative Cost-Effectiveness of Each Measure

Robust and regular oversight and informational hearings must accompany any post-2020 climate policies. We believe ARB should, at a minimum, review each current regulation resulting from AB 32 and determine if, (1) the regulation has accomplished the intended GHG reduction objectives or, (2) if the regulation has failed to achieve its goal and may simply have placed undue burdens on California's businesses and consumers without reducing our GHG emission levels, and (3) if there were a more effective means of achieving the intended reduction. Each measure adopted in the 2030 Target Scoping Plan and accompanying regulations should be held to the same standards of accountability. (CCPC)

Response: This comment does not request any change to the Proposed Amendments, and appears to be focused on all measures included in the proposed 2017 Scoping Plan Update. This comment is therefore outside the scope of the current rulemaking.

N-1.4. Comment:

Overarching Issues

The AB 32 Environmental Justice Advisory Committee (EJAC) started meetings about the 2030 Target Scoping Plan in December 2015. In addition to committee meetings across the state, the EJAC hosted a robust community engagement process in July of 2016, conducting 9 community meetings and collecting over 700 individual comments. The recommendations below are informed by those meetings, EJAC member expertise and comments received. To help make our recommendations more actionable, we sorted them into five themes that are described in more detail below and throughout this document: partnership with environmental justice communities, equity, economic opportunity, coordination, and long-term vision. While our recommendations are sorted by sector, we intend them to be read and implemented holistically and not independently of each other.

Partnership with Environmental Justice Communities

- | | |
|---|--|
| 1 | <p>Encourage public engagement and a culture shift in California to step up the implementation of our state's climate plans, using the following strategies:</p> <ul style="list-style-type: none"> a. Develop a communications plan to get everyday people excited about our climate programs. The plan must focus on the health and socio-economic impacts of air pollution and climate change, and include |
|---|--|

	<p>innovative, multilingual delivery methods like integration into school curriculum, technology applications, or Public Service Announcements (PSAs) to convey how air pollution and greenhouse gases are related to increases in hospital visits, lost wages, and economic insecurity.</p> <p>b. Promote community-level climate projects to show people how they are done and what they can accomplish.</p> <p>c. Create a “report card” for elected officials that show community members how officials voted on regulatory policies and the implications of those policies.</p> <p>d. Create a “report card” on Scoping Plan implementation that is updated every two years, using metrics identified in the Scoping Plan.</p>
2	Emphasize and demonstrate neighborhood-level solutions that draw on community ideas, rather than just taking a top-down approach. Ensure long-term community engagement and pre-assess projects in the targeted community and conduct at least five-year follow-up to ensure that projects result in community-directed benefits.
3	Continue to convene the EJAC beyond the Scoping Plan process. Implementation of the Scoping Plan can tap on the expertise and relationships of the EJAC members and their networks. Public policy is more successful when there is broad public awareness to ensure its success and oversight.
Equity	
4	ARB must better balance reducing greenhouse gases and reducing costs (cost compliance) with the other AB 32 goals of improving air quality in EJ communities while maximizing benefits for all Californians. There has been too much emphasis on reducing costs to industry, and not enough attention on reducing emissions and their associated costs in EJ communities.
5	Equity must always be a primary consideration when examining issues in any sector. Decades of cumulative impacts and inaction have led to a sense of urgency in needing to resolve adverse health and economic issues in disadvantaged communities. To demonstrate progress and build trust, both short- and long-term activities need to result in positive, immediate, and measurable impacts in these communities. ARB must

Overarching Issues

	conduct an equity analysis on the Scoping Plan and each sector. Work with EJAC on the analysis and the right questions to ask.
6	All climate goals and policies need to have metrics and baselines quantified to ensure that actions are meeting targets and goals over time. Each sector’s data must show historic emissions and future trends (both business as usual and how much reduction if certain programs are implemented). Each emissions sector, must calculate goals for emissions reduction to 2030; see example with the Short Lived Climate Pollutant strategy. These metrics must also include public health outcomes and issues.

7	ARB must develop contingency plans for mitigation and adjustment to the overall plan if emissions increase in benchmark years (due to huge leaks like Aliso Canyon, or if certain programs fail to reduce emissions). Timely emissions data will also allow ARB to adjust or incorporate new strategies as needed.
8	Expand and integrate real-time air quality monitoring, citizen science, and SEPs (supplemental environmental projects) in disadvantaged regions, including the California/Mexico border region. Monitors must be placed throughout regions to ensure we have an accurate understanding of air quality issues in that region. Consider a carbon tax that funds monitor installation and maintenance at every school in California.
Coordination	
9	Achieving our ambitious 2030 targets will require ARB to work with other agencies, jurisdictions, and program processes. Coordinate meetings between the interagency working groups (IWG) and EJAC, to encourage information sharing and mutual cooperation between the groups. Improve coordination among state, federal, and local agencies with regard to their planning and implementation activities. Support cities and local implementation of Energy and Climate Action Plans.
10	Coordinate strategies to prevent and address sprawl with equity at the center. Sprawl has negative environmental impacts on transportation, air, water, and more. New projects must not create adverse impacts like displacement of existing residents. Negative Declarations need to be phased out. All new greenhouse gas sources must be mitigated.
11	All policies and programs must adopt strong, enforceable, evidence-based policies to prevent displacement of existing residents.
Economic Opportunity	
12	Maximize job and economic benefits for Californians. Develop a just transition for workers and communities in and around polluting industries with a pathway for them to be first in line for jobs in the green economy. Include a section in the Scoping Plan on healthy, well-paid jobs and broad economic benefits, especially targeted for EJ communities, for jobs that don't require a worker to sacrifice his or her health in order to support a family, as is currently common. These efforts must emphasize capacity building in the community and outline fair hiring practices and policies, and be first focused on transitioning workers from polluting industries.
13	Benefits from Scoping Plan implementation must be accessible to Environmental Justice communities. Vouchers to help access new technologies, geographic distribution of resources and investments to disadvantaged communities, and transparent/accessible engagement in any planning and decision-making processes are essential.
14	Build in incentives and support for compliance. Incentivize behaviors that protect and improve disadvantaged communities; both on a large scale (e.g.,

	industry and agriculture) and at a community level (e.g., completing communities with paved roads,
Overarching Issues	
	sidewalks, bike/pedestrian paths, and planting trees). Explore effective strategies for change without incentives.
15	Ensure that AB 32 economic reviewers come from various areas around the state to represent insights on economic challenges and opportunities from those regions. The Environmental Justice Advisory Committee must choose at least half of the members. Ensure that the EJAC receives ready and timely notice of and access to any economic reviews, in time to give advice to and guide the process.
Long-Term Vision	
16	<p>The Scoping Plan must not be limited to examining interventions and impacts until 2030, or even 2050. What we do today and for the next 30 years will have impacts for seven generations, so our planning and analysis must have a longer-term scale to prevent short-sighted mistakes and rather reach our long-term vision. We request that all policies and analyses include this long-term vision.</p> <ul style="list-style-type: none"> a. Leave fossil fuels in the ground b. Do not create new infrastructure that relies on fossil fuels, including natural gas, fracking, pipeline development, crude oil shipments and processing c. Just transitions model of moving toward local living economies that prioritize the well-being of communities
17	The EJAC expects to see the largest proportion of reductions of greenhouse gases take place in California in the future. ARB must prioritize actions and investments in California EJ communities before looking at other Californian communities or outside of California.
18	Achieving our 2030 targets will require more effective implementation and creative innovation than we have ever done before. The Scoping Plan must prioritize whenever possible the innovation of new technologies or strategies to reach even deeper emissions cuts. These innovations must put EJ communities first in line for environmental and economic opportunities.

Industry	
Equity	
1	State in the Scoping Plan that it is a priority to reduce emissions in EJ communities, and to ensure no emissions increases happen there. Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities.

2	Use a "loading order" for Industry similar to the one that is used by the California Energy Commission for supplying demand. Always prioritize the approval and use of the most efficient and low-carbon technologies, facilities, and projects over high-polluting ones.
3	Address localized impacts of short-lived climate pollutant emissions, such as black carbon from all sources.
4	<p>A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. In addition:</p> <ul style="list-style-type: none"> a. Increase enforcement of existing environmental and climate laws, increasing penalties for violations in DACs. b. Establish a state run "Carbon Investment Fund" allowing the private financial sector to invest in Carbon Futures. Pay dividends through enforcement fines, permit fees and carbon tax receipts. c. Better coordinate climate pollution and local criteria pollutants programs. d. Place individual caps on emission sources, rather than using a market-wide cap. Set up a per-facility emissions trigger that will tighten controls when a certain level is reached. e. Establish a moratorium on refinery permits. f. Set goal of 50% emissions reduction in Oil and Gas sectors by 2030. Aggressively reduce emissions from these sectors, including fugitive and methane emissions from extraction and production. g. Put emissions caps on the largest polluters. h. If Cap-and-Trade continues, do not give out more free allowances. i. Do not exempt biomass burning activities. j. Do not allow regulated entities to apply for California Climate Investments funding. k. Increase the floor price to the real price of carbon; use the highest price offered, not the lowest. Incorporate industry's externalized costs into the cost of carbon (as is done with the mitigation grant program at Port of Long Beach). Calculate the cumulative impacts so they can be mitigated. Ensure that polluting facilities are paying the societal costs of their emissions, rather than externalizing them.

5	The Scoping Plan Economic Analysis must consider carbon tax, command and control regulation, and Cap-and-Dividend or Fee-and-Dividend. Cap-and-Trade must be eliminated. The price of carbon must be increased, with the resulting funds invested in local communities to ensure all benefits from a greenhouse gas free future.
6	Expand the definition of <i>economy</i> to include costs to the public (e.g., U.S. EPA social cost calculator). Conduct an economic analysis that would account for the cost to public health (beyond cancer, respiratory and cardiovascular diseases) and environmental burdens from greenhouse gases. Include the Integrated Transport and Health Impacts Model (ITHIM) in the analysis. Ensure that ARB coordinates with other state agencies in this effort.
7	Ensure that the Adaptive Management tool is adequate for real-time monitoring and intervention. There must be at least two EJAC members on the Adaptive Management work group. To demonstrate how the tool can help communities, complete an Adaptive

Industry	
	Management analysis for Kern County.
8	To address tension between workers and community members who live in polluted areas, there needs to be access to economic stability and a just transition to the new clean economy. Ensure that workers in Environmental Justice communities whose livelihood is affected from a move to cleaner technologies have access to economic opportunities in that new clean economy and that local businesses continue to employ workers from that community.
9	Do not commit California to continuing Cap-and-Trade through the Clean Power Plan. Since carbon trading cannot be verified, ensure that the Clean Power Plan power purchases are from sustainable, renewable power plants.
10	Eliminate offsets. Actions and investments taken by industry to reduce emissions need to be reinvested in the communities where the emissions have occurred. Any benefits from greenhouse gas reduction measures must affect California first. In addition to California emissions, also consider activities that can reduce pollution coming from across the Mexican border, to reduce emissions in the border region. Do not pursue or include reducing emissions from deforestation and forest degradation (REDD) international offsets in the Scoping Plan.
Coordination	

11	ARB needs to examine ways to increase its partnerships with and oversight over air districts using its existing authority. Local air districts need to be held accountable to the same standards as ARB. Promises need to be documented and strictly enforceable. If an air district chooses to have stronger standards than ARB, that air district must have the power to enforce those stronger standards without interference from ARB.
12	<p>Stop “passing the buck” from agency to agency and fix the problems. All agencies need to take responsibility for all pollutants. Coordinate efforts among agencies when necessary, and among local governments and communities. Implement the following measures:</p> <ul style="list-style-type: none"> a. Improve community and neighborhood level air pollution monitoring. b. Add EJ members to all agency boards and committees. c. Tier pricing for allowances for facilities in EJ communities, making it more expensive to pollute in those communities. d. Improve communications about air quality between polluters and schools and nearby residents, both for individual accidents and in terms of overall facility emissions. Develop a cooperative, productive discourse. e. Provide easily accessible and immediate notification to schools and nearby residents in the event of a facility accident; current notification is much too slow. Develop and make accessible tools like the real-time air quality advisory network (RAAN) phone application, so residents can access real-time air quality information at the neighborhood level. f. Establish better coordination between enforcement agencies. Expand air quality night enforcement so that all communities have around-the-clock enforcement to address off-hours violations.
Partnership with Environmental Justice Communities	
13	Create a thorough air quality monitoring system and deputize the community to participate in that network through databases, apps, and community science. Fund a program to provide communities with the tools and training they need to participate. Identify the pockets not being monitored and also the hot spots. ARB must take a greater responsibility for monitoring. Ensure that all monitoring covers both greenhouse gas pollutants and criteria
Industry	

	pollutants, to expand the state's databases and accurately characterize all communities, so that CalEnviroScreen can more reliably identify areas that qualify for funding. Make monitoring transparent and accessible.
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Energy, Green Buildings, Water	
Equity	
1	Develop aggressive energy goals toward 100% renewable energy by 2030 to reach emissions reduction sooner, especially if other sectors lag or increase emissions. Increase 2020 reduction target to 50%, aiming up to 100% reduction by 2050.
2	California must fully practice the state's energy loading order: prioritize all cost-effective energy efficiency, then demand response, and finally renewables and distributed generation. These priority strategies, in combination with energy storage, must be fully utilized prior to the use of natural gas power plants.
3	Expand rooftop solar in EJ communities, including desert communities. Use brownfields for solar.
4	Remove special considerations or exemptions for investor-owned utilities, and instead require them to develop power that is the most clean and efficient, and under the same rules and structure as their counterparts.
5	Imported electricity must not be considered renewable beyond the percent of renewable energy production (the renewable portfolio) currently existing in the exporting state. There must be no double-counting or incentives to encourage other states to burn fossil fuels.
6	Do not use Cap-and-Trade (or carbon trading, offsets) for the Clean Power Plan. The Clean Power Plan must ensure power is generated from sustainable, renewable sources.
7	Do not provide energy credits for biomass burning or count it as renewable energy. Make wood chips available from dead trees to use as mulch in gardens (don't burn it).
8	Carbon capture and sequestration power plant projects using captured carbon dioxide for enhanced oil recovery must not be certified as projects that sequester carbon for the purpose of carbon credits of any kind. Also, injection of carbon dioxide for sequestration purposes shall not take place without the express permission of all surface landowners above the zone of sequestration in order to qualify for carbon credits.

9	Climate investments and energy solutions (building retrofits, weatherization, solar, microgrids, etc.) must serve entire disadvantaged communities, rather than just individual buildings or homes. Other populations of note include: fixed-income, seniors, people with chronic conditions, and other low-income residents.
10	Develop innovation hubs for disadvantaged communities in order to support innovations, development and use of clean energy and weatherization, like low-cost solar cell stacking.
11	Upgrade residential building electrical systems to support clean energy upgrades in urban, rural and unincorporated communities. Increase progressive types of code for future upgrades. State funds for clean energy technologies in disadvantaged communities must allow for funding for maintenance and upgrades necessary for clean energy technologies. Create green development bank to fund energy efficiency programs in disadvantaged communities.
12	Prevent and mitigate negative land use impacts from energy projects, including increased dust from clearing land, sprawl, displacement, increased traffic, and understanding costs of these emissions projects.

Energy, Green Buildings, Water	
13	Set a moratorium on new oil and gas operations (refineries, power plants, fracking wells, etc.).
14	Phase out natural gas-based appliances and technologies, and transition to electric and solar thermal technologies. Offer energy efficient household appliance upgrades to low-income residents in particular.
15	Support tree planting and green infrastructure in communities to reduce energy use for cooling buildings. Such infrastructure could include cool roofs or permeable surfaces to cool community and reduce energy consumption.
16	Set and enforce greenhouse gas reduction targets for existing buildings and improve building codes. Broaden the definition of a “green building” to include retrofits of existing buildings in disadvantaged communities. Identify and implement best practices for retrofitting existing buildings.
17	Set goals for new and green buildings: all new constructions to be zero net energy (ZNE) by 2020, with none using natural gas or biogas. Include affordable housing buildings in ZNE goals.

18	Develop standards and support the construction of “living buildings” (regenerative buildings that more closely follow natural ecosystems, with features such as solar, water capture, efficient and affordable transportation options, etc.) within disadvantaged communities.
19	Provide direction to industry on best practices for rapidly moving toward widespread design and construction of green buildings within disadvantaged and low-income communities, and incentivize developers to adopt the standards and implement them. Ensure that building or retrofit costs are not passed along to low- and moderate-income tenants by providing tax incentives, or by adopting policies that prevent having those costs passed on to them. Share energy savings with renters.
20	Make pumping of water by the State Water Project in California 100% renewable by 2030, with consumers of the water paying for renewable energy installation and production along the project right-of-ways.
21	If geothermal energy is developed, ensure that it is benefiting, and not harming, the local community.
22	Identify the energy use and reduction goals for the proposed California Water Fix and Eco Restore project (formerly the Bay Delta Conservation Plan), including the pumps at Tracy (the single largest energy user in California).
23	Encourage regional self-sufficiency and conservation to maximize water supply through water recycling and rainwater capture, low-impact development, end-user education, and use of native plants, and by enforcing the proper use of landscape water. Provide resources to help low-income households install grey water designs for landscape irrigation.
24	Prioritize pollution prevention in all AB 32 projects and regulation. The provision and distribution of affordable, safe drinking water for all must be the highest priority. ARB is subject to code enforcement of making water available.
25	Stop investing in dirty energy. Eliminate subsidies and financing for fossil fuels and in technologies such as corn-based biofuels, agricultural methane, biomass burning, waste-to-energy, or other unsustainable technologies that result in negative impacts on EJ communities. Use funds instead for clean energy projects in EJ communities.
Coordination	
26	The California Energy Commission (CEC) must evaluate all renewable energy projects under the renewable portfolio standard (RPS) for lifecycle emissions and

	co-pollutants to ensure they do not create new problems in overburdened communities. The CEC must render
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Energy, Green Buildings, Water	
	ineligible those technologies that increase local air quality burdens without direct and current 200% mitigation of all air quality impacts within ten miles of the project location. The CEC must ensure that imported renewable energy, including that from tribal lands, is consistent with California requirements.
27	Prioritize the siting of renewable energy, grid storage, microgrids, and community choice aggregation projects within communities identified by CalEnviroScreen. EJ communities need to be able to reap the environmental and economic benefits of these energy projects. Pilot 10–100 microgrid projects in EJ communities. The California Energy Commission must prioritize and maximize clean energy research and development investments in disadvantaged communities through its Electric Program Investment Charge (EPIC) Program and actively engage those communities in developing the investment plan for that work. Ensure that power companies do not disincentivize neighborhood-level renewable energy generation through taxes and feeds.
28	Avoid and mitigate any increased emissions from energy operations, and prioritize disadvantaged communities in this effort. The California Independent System Operator (“CAISO”) must not pursue regionalizing the energy market if there are negative impacts like natural gas plant emissions increases or health effects on disadvantaged communities. Ensure an effective and aggressive adaptive management plan if there is grid regionalization. Prevent negative unintended consequences with strong inter-agency coordination between the Air Resources Board, California Public Utilities Commission (CPUC), California Energy Commission (CEC), CAISO, and local air districts, and in related proceedings and policy discussions.
29	The California Energy Commission (CEC) must provide guidance to state and municipal energy agencies to lower the barriers to pursuing deep energy retrofits to upgrade homes, businesses, and public institutions in low- to moderate-income communities. This can happen through the CEC’s SB 350 Barrier Studies and any related follow-up studies.
30	Mandate local jurisdictions to install energy-efficient alternatives in community buildings (e.g., shopping malls, recreation centers) as they do in government buildings.

31	Coordinate federal, state, and local agencies to create a one-stop shop for residential, commercial, and industrial energy efficiency and renovation programs. Focus on the whole house rather than on one aspect at a time, so that multiple programs can be more easily accessed, and on retrofitting the whole community to leverage economies of scale. Make homes more energy efficient before installing renewables. Establish pilot projects to retrofit substandard low-income housing with federal Housing and Urban Development (HUD) funding.
32	Implementing agencies must build training partnerships with local institutions that have a proven track record of placing disadvantaged workers in career-track jobs (such as community colleges, nonprofit organizations, labor management partnerships, state-certified apprenticeship programs, and high school career technical academies).
Partnership with Environmental Justice Communities	
33	Increase literacy about clean energy programs and services, especially for people in geographically, linguistically, and/or economically isolated communities. Use trusted sources of information such as community-based organizations, school curricula, outreach to immigrant communities in-language and employ culturally appropriate and multigenerational messaging techniques.
34	Identify, implement, and standardize metrics to track energy savings, quantify energy reductions, conduct post-project assessments to ensure accountability, and survey local

Energy, Green Buildings, Water	
	activities to determine if strategies are working (or not). Use EJ residents as a resource for data collection.
35	Promote more education to water end-users about ways to conserve water and energy.
Economic Opportunity	

36	Promote the development of community-driven clean energy projects that hire from disadvantaged communities, prioritize community ownership of (and equitable access to) clean energy technologies, maximize energy bill reductions for low- and moderate-income communities within disadvantaged communities, and prioritize anti-displacement strategies. For climate projects, employ project labor agreements, best-value contracting and local/targeted hire goals to provide access to career-track construction jobs for disadvantaged workers. In consultation with state workforce agencies, direct implementing agencies of climate programs to develop specific goals to train and facilitate employment of workers from disadvantaged communities. Use CalEnviroScreen, other robust screening tools, and local unemployment data to identify and prioritize communities for job creation programs.
37	ARB shall work with appropriate state agencies to identify and develop data and criteria for measuring economic and employment co-benefits resulting from AB 32-related public investments. Develop measurable targets and a process for determining if those targets are met. To improve transparency, report progress or lack of progress to the community regularly. Provide better oversight of climate change investments to ensure they benefit all EJ community members.
38	Maximize carbon reduction and energy savings by directing implementing agencies to promote the highest quality work, standards for participating contractors, and minimum training and skills for workers.
39	Provide scholarships for college work in relevant clean energy fields.
40	Develop incentives, rebates, and financing mechanisms to accelerate equitable access to clean energy technologies in low-income households, apartment buildings, small businesses, and other community-serving facilities such as community centers, churches, health clinics, schools, parking lots, local industry buildings, and community-based organizations. Surplus energy can be invested back into the community or to cleanly fuel industrial facilities. Eliminate landlord signature for energy improvements or rebate application programs; obtaining a signature can be difficult and landlords sometimes increase rent after upgrades.
41	Develop incentives and phase in requirements for renters and landlords to provide energy efficiency upgrades and provide upgrades that enable buildings to use renewable energy technologies and water capture. Update building and zoning codes to support renewables. Enable builders to fast-track a project if it includes solar. Follow U.S. Department of Housing and Urban Development (HUD) program guidelines so landlords cannot raise rents due to improvements.

42	Lower finance barriers and increase access to low- and no-interest energy efficiency financing for the low- to moderate-income single-family, multifamily, and small business sectors. This includes credit enhancements, interest rate buy downs, rebates, low-interest loans, and supporting the use of alternative measures of creditworthiness to provide greater access to affordable capital.
43	If federal tax credits for residential solar installations are discontinued in the future, California must make up the difference with state tax credits and rebates.
44	If federal tax credits for small business solar installations are discontinued in the future, California must make up the difference with state tax credits and rebates.
Energy, Green Buildings, Water	
45	Protect low-income households from energy price spikes.

Transportation	
Overarching Principles	
<p>We envision a California where all communities breathe clean air and have access to safe, affordable, clean transportation options. The following recommendations will help to achieve this vision. The themes present in this Transportation Section that can be lifted up as overarching principles are:</p> <ul style="list-style-type: none"> a. Access to clean transportation technologies b. Meaningful investments in disadvantaged communities c. Capturing economic benefits in disadvantaged communities d. Coordination of state and local agencies e. Reporting on actual impacts of programs, particularly community level impacts f. Robust community participation 	
Equity	
1	The top priority for transportation planning and investments is to reduce vehicle miles traveled (VMTs) while increasing access to affordable, reliable, clean, and safe mobility options in disadvantaged communities.

2	Examine mobility regionally, as there are different challenges and opportunities in different areas of California. For example, reduce transportation emissions along the border with Mexico by focusing on cross-border commuting. Reduce the long border wait lines and idling by increasing lanes for walking and biking, providing zero-emission bus and shuttle options, and increasing transportation infrastructure to support traffic.
3	Expand transit services to provide neighborhood-level access, use different vehicle sizes and types to ensure economies of scale, sustainability, and accessibility to disadvantaged communities. Increase access to buses and trains for youth, students, elderly, those seeking medical care, and low-income riders. Employ free or discounted transit passes for these groups. Prioritize funding for buses in areas where buses are relied upon more by low- and moderate-income commuters in disadvantaged communities.
4	Define <i>infrastructure</i> not just to include highways, freeways, new fueling stations, and roads, but also sidewalks, bike paths, and green infrastructure. Invest in multi-modal and shared transportation instead of building new freeways. Furthermore, state and local government agencies must not count building freeways as a GHG reduction strategy.
5	Ensure that there is sufficient infrastructure to support new and current low emission vehicle types (i.e. bikes, electric vehicles, etc.). The state must strengthen and identify more opportunities to fund and mandate local land use decisions that support a low-carbon future and protect the health of local residents.
6	<p>Promote more community-friendly land use planning that prioritizes the health and economic wellbeing of environmental justice communities and is developed in close consultation with community members. We recommend the following community-friendly land use planning strategies:</p> <ul style="list-style-type: none"> a. Design and implement new incentives, beyond tax credits, to encourage infill and mixed-use development over sprawl. Develop and implement land use, building code, and permitting changes to streamline planning. b. Increase support for use of cleaner, safer sidewalks and bike paths. Better lighting,

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	<p>increased distance or barriers from roadways and freight railways. increase bike and path/sidewalk sweeping</p> <ul style="list-style-type: none"> c. Ensure that the placement of bus garages, terminals, and hubs does not disproportionately impact environmental justice communities and pursue measures to reduce environmental impacts from these facilities. d. Promote and fund projects that create clean, safe, and accessible mobility pathways and networks for environmental justice community members, particularly more sensitive populations such as youth, elderly, and those with health problems. Mobility options must include more active transportation options such as bike paths and sidewalks. e. Improve existing transit resources, including increasing the number of bus stops where needed, developing intelligent and connected bus stops, and improving bus stop infrastructure (e.g., covered and better lit bus stops with more benches). Transit planning and maintenance must prioritize safety and coordinate with last mile initiatives. Transit planning must also prioritize efficiency and support routes that promote accessibility, reduce health impacts from criteria pollutants, and lower GHGs. f. Plan for dedicated bus lanes on the freeway to promote the efficiency and use of public transportation. The buses themselves must be cleaned more frequently and must integrate more easily with other mobility options such as biking and trains/trolleys to help increase user satisfaction and ridership.
7	Target truck fleets and vehicle fleets with electrification and cleaner, sustainable fuels to achieve the quickest, most significant reductions in emissions. The state must increase the fleet turnover target to at least 40%.
8	Actively support and implement California Cleaner Freight Coalition's recommendations to California's Sustainable Freight Action Plan.
9	Develop strategies that ensure small independent trucking companies and concerns are incentivized to transition to zero or near-zero emission vehicles as well as more efficient truck technologies.
10	Restrict truck routes and travel times and limit new trucking operations to reduce vehicle miles traveled to reduce their operational impacts in disadvantaged communities. Increase monitoring and enforcement of these requirements.
11	Support sufficient charging and refueling stations along freight corridors.
12	Increase the required reduction of carbon intensity of fuels under the Low Carbon Fuel Standard from the current 10% to 30% by 2030.

13	Eliminate the assumption in the Low Carbon Fuel Standard Life Cycle Analysis (LCFSLCA) that methane is a necessary by-product of dairies. This will eliminate the awarding of avoided methane emissions credits to dairies. Instead, methane emissions must count as an emissions debit against the fuel. Conduct a new LCFSLCA using standard methodologies applied to all organic and artificial chemical energy sources.
14	Promote clean and renewable energy sources to power vehicles. Plan electric vehicle programs and electricity supply together. Increase coordination among energy and transportation agencies to help ensure the success of supporting initiatives.
15	Study the emissions reduction benefits from increasing gasoline prices.
16	In support of state electric vehicle goals, such as SB 1275, the state must develop and provide funding for a program that ensures deep penetration of electric vehicle use and charging capacity in disadvantaged communities. This must include a pilot program that

Transportation	
	<p>does the following:</p> <ul style="list-style-type: none"> a. Funds demonstration program placing new and used electric vehicles, along with associated charging and maintenance infrastructure, in at least seven low-income and disadvantaged communities at the residential level, to evaluate best practices and accelerate their integration in these communities statewide b. Ensures a proper diversity of population density: urban, suburban, and rural areas c. Prioritizes areas with aging infrastructure d. Focuses on expanding access to electric vehicle use in schools in disadvantaged communities

17	<p>Accelerate ownership and access to zero-emission vehicle technologies, through the following strategies:</p> <ul style="list-style-type: none"> a. Universal application and point-of-sale rebates or vouchers for new and used electric vehicle and other clean energy programs in place by June 2017 b. Rebates for used electric vehicles available (outside of Enhanced Fleet Modernization Program (EFMP) and Plus-up project) by June 2017 c. A minimum of 20% of non-luxury multi-unit dwellings have electric vehicle charging stations (or stubs) by 2020 d. A minimum of 25% of state investments in electric vehicle charging station infrastructure occurs within disadvantaged communities e. ARB's "Electric Vehicle Car sharing Program" funds at least 50 projects by 2020 f. Employment and Education Shuttle rebates to fund at least 20 ZEV or hybrid vanpooling and carpooling (including support for charging infrastructure) projects that support community-serving workforce training programs and employment by 2020 g. At least 20 "last-mile" free electric shuttle/bus programs providing transportation to community-serving facilities (e.g., clinics, community colleges, community centers, hospitals, government facilities, job centers, shopping centers) in place by 2020. <p>2020. There must be a regionalized effort to promote integrated solutions connecting community members from public transit to their destination.</p> <ul style="list-style-type: none"> h. All school districts in disadvantaged communities have electric school bus fleets by 2020. i. Provide incentives to small-businesses (particularly those heavily reliant upon goods movement) for the purchase or use of zero-emission medium- and heavyduty vehicles. j. Support and finance zero-emission truck and bus initiatives outlined in SB 1204.
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18	<p>Ensure that clean transportation infrastructure and mobility options are available in rural, indigenous, and small communities. Specifically:</p> <ul style="list-style-type: none"> a. Fund and support clean transportation options for low-density communities with less cars and transportation resources. Vanpooling, community-driven ride-sharing (i.e., Green Raiteros in Huron, California), more frequent buses, and bus routes are examples of more mobility options that are more targeted for rural and small communities. b. Target clean mobility incentives to farmworkers who may not have vehicles or need smog tests for polluting vehicles.
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Transportation	
19	<p>Improve access to transportation options (active transport, mass transit, ride-sharing) through the following recommendations:</p> <ul style="list-style-type: none"> a. Promote more effective outreach and information sharing about zero-emission vehicles and other clean mobility options, as well as information about daily air quality conditions. <ul style="list-style-type: none"> 1. Work with the car industry and ethnic ad agencies on advertising and more targeted campaigning in multiple languages. 2. Get information out through a cell phone application that is free and available in multiple languages. 3. Work with community-based organizations to ensure that this information is available to community members who do not have access to a smart phone. b. Promote and fund community-driven, community-owned, affordable and accessible ZEV shared mobility options in environmental justice communities.
20	<p>All SCSs and transportation project analyses, policies, and investments must include metrics around displacement and gentrification. Non-displacement of residents must be met as part of the permitting process and before awarding funds, and methods for enforcement must be identified.</p>

21	<p>California must promote a culture shift to more efficient and clean mobility options such as mass transit and active transportation. Streamline and promote widespread access to clean mobility options using the following recommendations:</p> <ul style="list-style-type: none"> a. Promote and incentivize telecommuting as a way to reduce vehicle miles travelled, particularly for communities that have been displaced from areas closer to their work. b. Decrease vehicles idling by working with appropriate stakeholders to retime traffic lights, develop adaptive traffic management systems using real-time data, promote the use of signage or other efforts to reduce idling at drive-throughs and other businesses. c. Partner with businesses and provide outreach, education, and incentives to encourage truck drivers and companies to reduce emissions, reduce idling, and promote more a more efficient use of medium- and heavy-duty vehicles. d. Encourage more ride-sharing by employers.
22	<p>The state must support research on the following topics:</p> <ul style="list-style-type: none"> a. Growth regional growth projections with an assessment of clean mobility needs in the future. b. Updated and more targeted, scaled down science on the cumulative impacts of pollutants within environmental justice communities. c. Unintended consequences from clean transportation policies and investments on low-income individuals and environmental justice communities (e.g. displacement, impacts on vehicle miles traveled). d. Impacts of road use fees to generate revenue and discourage driving.
Partnership with Environmental Justice Communities	
23	<p>Through robust community participation, ground-truth the actual impacts of program planning and implementation. Strategies include the following:</p> <ul style="list-style-type: none"> a. Conduct and prioritize community needs, network analysis, and mobility assessments. Transportation agencies and planning groups must be mandated to address mobility gaps in EJ communities and for seniors, low-income populations,
Transportation	

	<p>and people with disabilities.</p> <ul style="list-style-type: none"> b. Conduct equity analyses when evaluating and implementing transportation options to prevent adverse secondary effects in disadvantaged communities (e.g., the Los Angeles FasTrak program which resulted in more vehicles on artery streets, creating even worse air quality problems for those communities) c. Conduct equity analyses in transportation projects to ensure that investments go to those most impacted by pollution and economic disparities d. Benchmark and track where projects are implemented to measure the emission reduction progress and economic return in disadvantaged communities e. Measure emissions reductions by per capita VMT
Coordination	
24	<p>ARB must work with the California Energy Commission through its EPIC and ARFVTP funding sources must support the advancement of clean transportation innovations within environmental justice communities and must engage community-based organizations in investment plan development.</p>
25	<p>Sustainable Community Strategies (SCSs) must be improved in the following ways:</p> <ul style="list-style-type: none"> a. SCS compliance with ARB greenhouse gas reduction targets must only be based on documented land use and transportation changes. b. ARB setting strong target for all Metropolitan Planning Organizations. Eliminate the “5 and 10” default for Regional Transportation Plans (RTPs). c. Metropolitan Planning Organizations must only be allowed to authorize implementation of projects that are included in the most recent SCS. d. Transit agencies must be required to adhere to projected routes and costs in the adopted SCS unless alternatives demonstrate increased emission reductions while maintaining or improving access to alternative transportation choices. e. Implementation of SCSs must prioritize investments in disadvantaged communities.

	<p>f. ARB must consider California Transportation Plan 2040 and Regional Transportation Plan Update guidelines (see also section on improving coordination).</p>
26	<p>Strengthen oversight by state of local government activities. ARB must provide detailed guidance on local zoning to carry out climate and air quality priorities. Furthermore, state agencies need to give local transit authorities more direction about anti-discriminatory Title VI expectations, to promote more equitable funding of transit options, especially regarding fare increases and route changes that may limit access to transit.</p>
27	<p>Financially support transit operations and restoration of transit service and routes and expansion of services where lacking in disadvantaged communities.</p>
28	<p>Establish better interagency coordination among state, federal, and local agencies when planning projects and awarding funding. The following outline specific opportunities for improving coordination:</p> <ul style="list-style-type: none"> a. Coordination must be transparent and actively seek community and stakeholder input. b. ARB must consider the California Transportation Plan 2040 and Regional Plan Update guidelines in developing and implementing its own planning documents, including the Scoping Plan. c. ARB must improve coordination with California Environmental Protection Agency <p>(CalEPA) and the United States Environmental Protection Agency (U.S. EPA) to</p>
Transportation	
	<p>promote better scientific research on pollution impacts within environmental justice communities and pursue initiatives to prevent harmful cumulative impacts.</p> <ul style="list-style-type: none"> d. ARB, California Public Utilities Commission, and California Energy Commission must better coordinate electricity planning and the planning of program supporting electric vehicle use to help maximize the use of renewable electricity for transportation, to ensure infrastructure needs are met for electric vehicles, and to better understand opportunities for renewable integration efforts. e. CalTrans and local governments must prioritize greenhouse gas reduction and public health and safety in funding activities and policies.
Economic Opportunity	

29	Prioritize the advancement of economic benefits such as job and workforce training opportunities in disadvantaged communities. Build skills and capacities locally, so infrastructure can be maintained and further advanced.
30	Technical Assistance and Marketing, Education, and Outreach (ME&O) – The state must dedicate funds toward helping less-resourced communities and small businesses take advantage of clean transportation investment opportunities. It is important to develop community-specific technical assistance and ME&O plans to maximize efficacy of outreach efforts.
31	Job Placement and Training – The state must dedicate resources for community-based organizations that support clean energy career pathways for disadvantaged community members. These pathways must include but not be limited to: job placement, apprenticeship opportunities, and building skills that are transferable to a broad set of clean energy jobs.
32	Ownership and Access – The state must support the increased access to and ownership of clean energy and clean transportation technologies and mobility options in disadvantaged communities (discussed in more detail above).

Natural and Working Lands, Agriculture, Waste

Coordination

1	ARB and other state agencies (including the California Public Utilities Commission, California Energy Commission, Office of Environmental Health Hazard Assessment, Department of Toxic Substances Control, and CalRecycle) must undertake a process to examine the growing evidence that biomass and biogenic carbon have real and significant climate impacts, examine the long-distance transport contribution to overall greenhouse gas impacts of burning biomass material, and examine assumptions of health and environmental impacts from burning various materials considered to be biomass, including the impacts of biomass ash. Ash from burning biomass, urban wood waste, and other materials has been found to be dumped on California agricultural land in recent years, and this ash has been found to be contaminated with dioxin and other health-threatening chemicals. Before pursuing increased burning of biomass in California, ARB, the Natural Resources Agency, and related agencies must investigate where ash from the existing burning of biomass is ultimately being dumped, the environmental justice impacts and impact on agriculture, and the cost of biomass ash handling in California. This is of growing importance as new EPA regulations allow for the increased burning of waste and biomass at industrial facilities (i.e. industrial boilers, cement kilns), and as material deemed to
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	be biomass are exempt from compliance obligations under California's Cap and Trade program.
2	Establish better coordination between ARB, Caltrans, the California Energy Commission, CalRecycle, the Department of Toxic Substances Control, and other agencies whose purview include Natural Lands, Agriculture, and Waste-related emissions. Together, these agencies must be available for consultation with EJAC to support plan and policy development.
Equity	
3	<p>Data Collection – timely and comprehensive data collection is essential to avoiding negative impacts and ensuring co-benefits. Such data must include:</p> <ul style="list-style-type: none"> a. emissions from forestry and wood products, since forest management is a net source of greenhouse gases. b. wildlife habitat (including agricultural land) to facilitate conservation and link to the greenbelt. c. metrics to quantify the greenhouse gas benefits of managing natural and working lands. Achieve consensus on how to measure greenhouse gas emissions reductions from activities in natural systems. Discuss and agree upon these metrics with the interagency working group and community stakeholders.
4	No credits must be given for landfill or for biodigestors for greenhouse gas avoidance. The state's biomass garbage and all other incinerators, including but not limited to gasification, will be treated like other carbon-intensive industries and pay for all carbon emissions under California's Cap and Trade program. At a bare minimum, the state must align with the requirements of the EPA's Clean Power Plan (CPP) on this point. The CPP clearly recognizes that carbon dioxide emissions from burning the fossil fuel-based portion of garbage (i.e., plastics) must be counted. CPP also acknowledges that incineration undermines waste prevention programs, which have significant climate benefits. Beyond this minimum accounting requirement, the state already recognizes the benefits of using compost (from food, paper, wood, yard waste, and other natural materials in the waste stream) to store carbon in the soil. Thus, the carbon dioxide emissions of burning such materials must also be counted in the state's Cap and Trade program. Additionally, the state must revoke all existing incinerator carbon credits. Disincentivize and discourage locating biomass and

	digesters in disadvantaged communities or in close proximity to housing.
5	<p>Healthy Soils – a critical element to land and waste management is soil regeneration.</p> <p>Strategies include:</p> <ul style="list-style-type: none"> a. Implement climate action plan goals for urban agriculture and community gardens with integrated composting strategies. b. Research and market development for creation, storage, and application of compost for environmental health protection and carbon sequestration, the composting of woody materials together with manure, and agricultural land application of mulch from excess woody materials. c. Promote urban hydroponics and aquaponics. d. Ban agricultural burning of waste; Provide a baseline credit for applying carbon back to soils. e. Promote composting by providing education and assistance to implement composting in all communities. Support the expansion of infrastructure for composting where necessary, and map out the mechanisms for composting in each community. Share best practices between municipalities to ensure all residents have access to programs. Incentivize neighborhoods to compost food waste from schools and at the community level. Establish communication plans that show Californians how to compost and motivate people. f. Promote biologically intensive (regenerative organic) agriculture for the variety of agricultural, environmental, and economic benefits it provides, and to rebuild soil g. Stop overgrazing h. Do not strip forest waste from the mountains to feed biomass plants; instead, sequester the carbon on site through chipping and burying. i. Manage forests to maintain a solid canopy and replant open areas immediately. j. Build clean air, water, and healthy soil consciousness aggressively. k. Mandate that all communities balance natural and working lands to sequester carbon and uptake pollution to replenish natural systems. l. Develop a simple metric for soil carbon or soil organic matter (SOM), to set up a meaningful reward system for carbon farmers who meet an obvious threshold of SOM or carbon sequestration.

6	<p>Waste diversion –</p> <ul style="list-style-type: none"> a. Establish waste diversion programs like “pay as you throw,” where people pay per pick up amount b. To minimize emissions from waste and recycling trucks fleets, establish more efficient routes and use cleaner fuels. c. Enforce the mandate that commercial buildings have recycling programs d. Set composting as the primary goal for incentivizing waste diversion. Waste needs to be composted and recycled as close as possible to its point of origin and/or collection. Communities must take full ownership of their waste and not export it to disadvantaged communities, and must recognize that impacts stem from not only the waste, but also the use of diesel trucks to carry the waste away. Encourage the use of waste as a resource and support infrastructure investments that maximize recycling and composting programs. Ensure that environmental justice communities do not become the repositories of this excess waste. Finished compost can be exported where it’s needed to support forestry and agriculture focused carbon sequestration goals e. Divert dairy waste as fertilizer and for carbon sequestration before it can be converted to methane.
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7	<p>Waste from “renewable resources” like geothermal need to be evaluated, managed, and waste and other externalities must be considered, in the determination of renewable energy sources. Do not use or provide financial support or investment to gasification and biofuels as qualifying renewable options.</p>
8	<p>Develop more local agricultural processing centers so food is not being trucked long distances. Introduce a scoring system for food that indicates food-miles traveled. Encourage local food processing of food and meat, and educate people on the greenhouse gas reduction benefits of not eating meat. Establish public financing for healthy, environmentally sound food sources.</p>

9	<p>Restrict sprawl—</p> <ul style="list-style-type: none"> a. use productive lands for production. Do not use usable agricultural lands for solar and wind farm projects. Such projects produce only a few, short-term jobs and the electricity is sent to large population centers, which results in farmworker displacement and a net job loss. Recognize that with new agricultural technologies, lands seen as “marginal” are greatly reduced. If solar or wind farms are created, provide job training locally for long-term, well-paying jobs operating and maintaining those technologies. b. encourage less driving. c. Support lifecycle analyses of sprawling developments to determine long-term economic and societal costs versus infill projects, to identify actual costs. d. Support local training, education, and incentives for architects, planners, engineers, and developers to design and develop infill building projects rather than sprawling developments. Provide incentives such as guarantees for a more streamlined planning and approval processes for infill projects. e. Protect greenspace and expand it in disadvantaged communities, insure equity though better enforcement of SB375/SCSs. f. Identify, develop, and implement policy tools to prevent the current trend of gentrification and displacement of local residents, businesses and people of color, pushing residents and people of color out of their communities. Do not provide greenhouse gas reduction funds for improvement projects that will displace current local residents, businesses, and nonprofits.
10	<p>Encourage watershed inventory and awareness. We need better infrastructure and drainage in low-income communities to eliminate pooling polluted water on neighborhood streets and property; and that addresses the high pollution levels that lead to asthma and other illnesses.</p>
11	<p>Integrate urban forestry within local communities. Revise the goal of increasing tree canopy by 5% by 2030 to 20%–30% by 2030. Conduct research to identify methods of achieving that increase given drought conditions. Include urban tree and greenspace maintenance, not just planting/creation.</p>

12	Build biomass, do not burn biomass. Instead of incinerating biomass from trees and municipal solid waste, which puts more carbon dioxide into air immediately, we recommend ARB expand its work to identify and support methods for returning that carbon to the soil, such as composting biomass together with manure. Investigate the growing evidence of carbon sequestration benefits from applying compost to grasslands (resources include the Marin Carbon Project and UC Berkeley Dept. of Environmental Science researchers). Additional benefits of such measures are the reduction of methane and nitrogen oxides, reduced synthetic fertilizer imports, and reduced water use.
13	Identify and establish effective methods for implementing food rescue programs, with quality controls to avoid dumping inedible food on communities. Identify strategies for
	getting edible food to those who need it. Incentivize these programs and promote communication plans for projects, so all communities have access to successful plans.
14	Push innovation on measuring waste and learning how to conduct activities. Overcome infrastructure barriers in dealing with waste.
15	Perform a complete lifecycle analysis of dairy and other bio-digester technology and related infrastructure investment. If biogas from dairies is converted to bio-methane, ARB must mandate that vehicles servicing digesters and converters utilize that gas as a primary fuel source. This is a better use of the fuel than building new pipelines and related infrastructure to transport the gas to other locations.
16	Expand the definition of “urban forestry” to include “rural desert urban forestry,” “rural/urban interfaces,” and “rural desert communities,” so those areas can qualify for funds to support tree planting.
17	Support community land trusts to address gentrification and preserve affordability and access
18	Research and identify alternatives for dumping biosolids (sewage sludge) in disadvantaged communities. Pilot a program to explore and demonstrate better options.
Economic Opportunity	
19	Quantify potential local jobs created from regenerating forests, both urban and rural. Include jobs for maintenance of all green environments, and increase funding to support local workforce development in support of this industry. Fund

	green infrastructure technician training and tree care maintenance jobs for green space.
Partnership with Environmental Justice Communities	
20	In consultation with all stakeholders including tribal councils and local communities, design and implement healthy forest management strategies that ensure sustainability of the existing forest canopy and decrease extreme wildfire events.
21	ARB must implement a public outreach and education campaign on the climate and co-benefits of urban agro-forestry, as well as the myriad benefits of urban greening in creating livable, healthy communities.
22	Continue to work with local communities and other stakeholders to refine metrics and tools that better quantify the greenhouse gas benefits and co-benefits of managing natural and working lands, including urban green spaces and trees. Achieve consensus on how to measure greenhouse gas emissions reductions from activities in natural systems.

California Climate Investments	
Long-Term Vision	
1	Emphasize regulations that force the advancement of clean technologies. Ensure that nearterm technologies do not adversely impact communities and long-term investments moves towards zero emissions.
Equity	
2	Greenhouse Gas Reduction Fund projects must be transformative for disadvantaged communities, in ways defined by each community themselves. California climate investments must take a place-based, regional approach focused on the unique needs of the people of each region, and prioritize projects that boost regional capabilities and economies. The state must support the ability of communities to use technology to communicate progress to the state. These projects must never result in displacement.
3	Within SB 535, further prioritize attention and funding for disadvantaged communities that experience increased greenhouse gas emissions despite implementation of AB 32 programs.

4	Create a formula for funding allocations that ensures investments are equally distributed across DACs in California.
5	To ensure adequate and continued funding of programs, EJ communities must have access to additional funding beyond Cap-and-Trade and the Greenhouse Gas Reduction Fund.
6	No funding must be given to fossil fuel-based industries or any regulated entities under AB 32.
7	Increase accountability of all grantees with regard to reductions claimed for their Greenhouse Gas Reduction Fund (GGRF) funded activities. Provide tools and training so communities can monitor progress based on data.
Economic Opportunity	
8	Spend Greenhouse Gas Reduction Funds (GGRFs) to incentivize local economic development so people can get well-paying local jobs closer to their homes and avoid displacement. Also incentivize local contracting to substantially involved community-based organizations so communities can build capacity at the local level. Community-based organizations must be required to demonstrate community support before receiving funds. Create a system that allows nonprofit organizations to earn points or access to the funds for providing improvements in Environmental Justice communities. For example, larger projects could include nonprofits as part of their proposals, or nonprofits could tap into Cap-and-Trade funds to help supplement their grants.
Partnership with Environmental Justice Communities	
9	The EJAC must help with outreach, accountability, and helping agencies prioritize investments. We must also inform the funding guidelines and investment plan.
10	The Greenhouse Gas Reduction Fund (GGRF) program staff representatives must attend EJAC meetings to provide information and gather input from EJAC members. ARB climate investment staff must identify ways to provide information to EJAC communities and gather community feedback in response. Insure community outreach and engagement is empowered to hold agencies accountable to help them prioritize activities and continually inform guidelines as they relate to ay investment plan.
11	Innovation must come from both the communities involved and ARB. ARB must support K– 12 and local college educational programs that educate students about climate change and teach them how to use tools to address it (e.g., students wearing technology that shows the air quality). ARB must work with schools and local colleges to support environmental

	literacy and sponsor multigenerational understanding of climate change and its impacts on the larger community. Funds gathered through polluter violation fees must be used to pay for educational programs in the affected communities.
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(EJAC)

Response: The comment was submitted by the Environmental Justice Advisory Committee (EJAC), and constitutes EJAC's set of recommendations on the ongoing 2017 Scoping Plan Update process. All of these recommendations are made in the context of the Scoping Plan Update, outside the scope of the Cap-and-Trade rulemaking process. However, some portions of the overall comment do make recommendations, or at least commentaries, on the Proposed Amendments. To the extent these comments are related to this rulemaking, ARB staff provides the following response.

Recommendation 4 under the Industrial portion of the comments asserts that there are a series of design flaws with the Cap-and-Trade Regulation, including recommendations that the program should not allow for free allocation, that the program should not exempt biomass, that there should be a moratorium on refineries, that the allowance floor price should be increased, and recommends increased enforcement of air pollution control laws in disadvantaged communities. This portion of the comment also recommends the creation of a Carbon Investment Fund for disadvantaged communities. This portion of the comments was also separately addressed in responses to 45-day comments L-3.2, L-3.3, K-1.5, and M-1.29. ARB staff also notes that this regulation would not be able to place a moratorium on refineries. As such, that portion of the comment is outside the scope of the Proposed Amendments.

Recommendation 5 of the Industrial portion recommends the elimination of the Cap-and-Trade Program. This comment was also separately addressed in response to 45-day comment K-1.3. Recommendation 7 of the Industrial portion relates to the Adaptive Management program, and was separately responded to in response to 45-day comment K-1.6. Recommendation 9 of the Industrial portion, as well as Recommendation 6 of the Energy, Green Buildings, and Water portion recommend not pursuing Clean Power Plan compliance through the Cap-and-Trade Program amendments. Please see response to 45-day comment D-1.2. Recommendation 10 of the Industrial portion recommends the elimination of offsets and not pursuing sector-based international forestry offset credits. ARB staff notes that this rulemaking has not proposed any changes to the offsets quantification usage limit, or to remove or add any new offset types. As such, the comment is outside the scope of the Proposed Amendments. Notwithstanding this, please also see response to 45-day comment I-4.

Recommendations 1 and 4 of the Natural and Working Lands portion also recommend not allowing exemptions for biomass. Since no changes to the

exemption for biomass have been proposed as part of this rulemaking, this comment is outside the scope of this rulemaking. See also responses to 45-day comments M-1.28 K-1.5 for more detail. The remainder of the comments are outside the scope of this rulemaking.

O. MRR

O-1.1. Multiple Comments:

Global Warming Potentials

Staff proposes to base the post-2020 program on global warming potentials (GWPs) for covered greenhouse gases from the IPCC's Fourth Assessment. While we support staff's proposal to update the GWPs relative to the Second Assessment, on which the pre-2020 cap was set, we recommend staff employ the most recent Fifth Assessment values. At the March 29, 2016 workshop on cap setting and allocation, staff remarked they would consider updating to the Fifth Assessment if and when it is in more general use and common practice in other jurisdictions. Then, as now, we find this explanation puzzling, as we can think of no other example of when California has waited on the actions of other jurisdictions before incorporating the most up to date climate science in its climate programs. California's entire climate program is predicated on establishing common practice, not waiting for it to materialize. While we appreciate the need to coordinate any changes in GWP values with California's linked partner jurisdictions, we encourage staff to revisit this decision and move to the most recent GWPs contained in the Fifth Assessment. (NRDC)

Comment:

Support updating global warming potentials:

EDF supports ARB's decision to update the GWPs relative to the second IPCC assessment but encourages ARB to continue considering moving to the fifth, rather than the fourth IPCC assessment. (EDF)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.2. Comment:

Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities. (EJAC)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons. To the extent this comment seeks to address amendments to the Cap-and-Trade Regulation, staff agrees that standardized metrics that ensure emissions reductions are being achieved are necessary, and the Regulation,

along with MRR, were developed to ensure this occurs. As this comment is general in nature, no further response is needed.

O-1.3. Multiple Comments:

SCPPA therefore urges ARB to defer proposed changes to the reporting requirements until such time as the problem (if any exists) is fully understood, CAISO has completed its stakeholder engagement process on the matter, and the state agencies have reached an agreement with stakeholder concurrence. Otherwise, we fear the hurried ARB regulations now may only serve to capture short-term Cap-and-Trade Program gains (which could possibly deter imports into California that are necessary to meet the state's RPS requirements), while undermining long-term emissions reductions initiatives across the West. This is one issue that does not have an immediate looming deadline, so it would be beneficial to take a few steps back to re-evaluate.

We believe it is also critical that each affected state agency have an equal voice in matters that directly impact their primary mission. It is imperative to recognize that California is part of the broader western electricity grid, and that any actions taken in our state may impact the larger regional market. Without a fix, any potential EIM benefits will be eviscerated by ARB carbon cost compliance obligation accounting; the consequence of which may be to deter new participant interest in, or even undermine existing participation within a flourishing market that has been widely touted by state energy officials, while burdening California ratepayers with the entirety of any accounting system for a broader market that they may not even benefit from. Further magnifying the need for inter-agency coordination is the fact that we (as a state) have yet to thoroughly explore how these GHG emission accounting efforts may translate to a broader, regionally integrated market as the Governor has sought to advance in the CAISO grid regionalization effort. The GHG accounting issue has proven to be an extremely contentious one amongst neighboring states in regionalization discussions. (SCPPA)

Comment:

ISO's Emission Factor

The proposed MRR amendments require that the ISO annually calculate/report/verify the volume of emissions applicable to the "remaining emissions" in the EIM. An "unspecified emission factor" is used to calculate the total California EIM dispatch emissions. However, the term "unspecified emission factor" is not defined in the CARB regulations. It is unclear if this is a default emission factor used elsewhere in the CARB regulations, or is a factor calculated annually by the ISO. If the ISO calculates this factor annually, EIM entities will be unable to forecast the volume of GHG compliance obligations that will result from engagement in the EIM, short of disallowing any transfers to California. This is because the EIM entity will not control whether it is dispatched into California, and if it is, whether the dispatch is its own generating unit with a specified emissions factor or a purchase in the EIM that is dispatched from the

EIM entity into California to which the ISO annual unspecified emissions factor will be applied. (EIM ENTITIES)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons. With respect to the interplay between MRR and the amendments to the Cap-and-Trade Program related to EIM, see responses to 45-day comments D-2.1 and D-2.4.

O-1.4. Comment:

[In a January 2016 letter to ARB, included as an attachment to each of their comments, the commenters and six other utilities state:]

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 certify RPS adjustment claims to align with the RPS Compliance Report timeline for REC retirement and reporting. This change allows the third party verifier to validate the RPS adjustment up until the RPS Compliance Report deadline of August 1.

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 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 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:

4A. 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.

2B. 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.

3C. 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 from an eligible renewable energy resource but not reported, the imported electricity cannot be claimed as specified.

(23) *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.

(34) *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 and for specified source ["and for specified source" included in MODESTOID letter but not in PG&E letter] 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. If the facility/unit is an eligible energy renewable resource then the electricity importer must have (1) a right of ownership or contract rights to the associated RECs; (2) and report the REC serial numbers associated with the imported electricity to section 95111(g)(2) ...

(56) *Substitute electricity.* Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section.

(PG&E, MODESTOID)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.5. Comment:

The Proposed Amendment to Section 95112(e) is Ambiguous

ARB proposes to require, as part of the reporting obligation for operators of geothermal generating facilities, that “[o]perators of geothermal generating facilities must also report whether the geothermal binary cycle plant or closed loop system, or a geothermal steam plant or open loop system.” Calpine proposes that this language be modified as follows:

Operators of geothermal generating facilities must also report whether the source is (i) a ~~the~~ geothermal binary cycle plant or closed loop system, or (ii) a geothermal steam plant or open loop system.

Calpine believes the above-modified language more appropriately reflects ARB’s intent in modifying Section 95112(e). (CALPINE)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.6. Comment:

§ 95122 Amendment of Point of Regulation for Imported LNG

Clean Energy commends the ARB’s acknowledgement and proposal to address the unintended competitive advantage that the MRR currently gives to imported LNG vehicle fuel versus California produced LNG. However, we are concerned that there is a potential loophole in the proposed regulation. Changing the regulated party from the California consignee to the importer of LNG does in theory “level the playing field” assuming that out of state LNG producers continue to act as the “importers” of the fuel to California. However, in order to avoid potential MRR compliance costs, an out of state LNG producer could conceivably “contract away” their liability by simply transferring title to the LNG customer at the out of state LNG plant (where shipments are picked up) or contracting through a third party logistics firm to accept title and risk of loss to the LNG at the out of state plant (and act as the importer). As long as the customer or logistics firm does not import and consume enough fuel in the aggregate to trigger a reporting obligation under MRR (and/or a compliance obligation under Cap and Trade), then the LNG shipments would presumably continue to have competitive advantage versus LNG produced in California that does carry such a compliance obligation and cost.

Therefore, we would urge the ARB to consider amending the proposed regulation so that an LNG producer that produces LNG vehicle fuel that is exported into California is subject to the MRR and Cap & Trade with respect to those LNG exports regardless of the entity that holds title to the product at the time it crosses the California State line. Potentially this could be achieved by modifying the definition of importer with respect to

LNG imports to state that, in the event that the importer does not otherwise trigger MRR or Cap & Trade with respect to the LNG volumes imported (due to the small size), that the producer of that LNG will be considered the importer for purpose of MRR and Cap & Trade.

This enhanced definition will ensure that the emissions of all LNG consumed in California are accurately captured and reported regardless if the fuel was produced in California or imported from out of state. Strict regulation of this magnitude is necessary to ensure that no entity delivering fuel for end use in California is able to avoid regulatory requirements and ensure a level playing field. (CLEANEN)

Response: The majority of this comment addresses the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons. To the extent the comment references amendments to the Cap-and-Trade Program, staff has proposed responses to these concerns in responses to 45-day comments C-1.8 and C-1.9.

O-1.7. Comment:

§ 95122(b)(8) Accounting for Biomethane CNG.

Clean Energy owns and operates an extensive network of CNG stations through which both fossil CNG and biomethane (or renewable CNG) are dispensed under Clean Energy's Redeem trademark. Clean Energy has contracts with a portfolio of producers to purchase this renewable natural gas that is scheduled through the SoCal Gas and PG&E distribution systems and sold to each Clean Energy customer. Many of these customers have signed biomethane contracts for a guaranteed supply.

Unfortunately, we remain concerned that the regulations in MRR Section 95122(b)(8) continue to make it difficult for a biomethane CNG customer to avoid imposition of Cap and Trade compliance costs on the biomethane CNG they purchase, notwithstanding the fuel's exemption under the regulations. As written it is left entirely to the discretion of the utility whether the utility elects to report the biomethane as exempt (and obtain verification of the exemption) or simply account for it as if it was fossil fuel natural gas. This makes it likely that a customer purchasing biomethane directly from Clean Energy will be assessed a compliance charge by the utility *as if the customer was consuming fossil fuel natural gas*.

We strongly urge the ARB to mandate that the utility allow biomethane suppliers and consumers who supply and/or consume biomethane through the utility pipes to provide the utility with verification of the exempt status of the fuel. The utility should also be forbidden from imposing Cap and Trade compliance costs on a biomethane purchaser that has demonstrated, in accordance with the regulation, that the fuel they are purchasing is exempt under the regulations.

If the proposed regulations are adopted as written, the implications for Clean Energy, our customers and the growing biomethane vehicle fuel industry in general are

significant. Customers will be subject to increases in transportation fuel costs as a result of the utility's cost of compliance – and be compelled to pay for phantom GHG emissions attributed to the fuel they purchase. Therefore, with respect to the sale of biomethane CNG through the LDC, we believe the ARB should require the utilities to report the volumes of biomethane sold through its system by third parties as exempt; provided the biomethane supplier provides all contracts, transaction confirmations, and credit generation support to the utilities to verify the volumes of biomethane sent through their systems. (CLEANEN)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons. To the extent the comment references amendments to the Cap-and-Trade Program related to biomethane, staff has proposed responses to these concerns in response to 45-day comment C-1.7.

O-1.8. Comment:

On Section 95118 (e) Site Specific Emission Factor and Production Data:

In the proposed amendments to the MRR, CARB staff have recommended nitric acid production facilities increase performance testing for N₂O emissions from the current single test required by federal rule 40 CFR § 98.223 (b) to twice annually, separated by at least 4 months of operation. CARB has indicated that the additional performance test is required due to observed variability in N₂O emissions from nitric acid plants reporting to the program.

In Simplot's operational experience, variability observed in N₂O emissions from the nitric acid process are not as a result of changes in manufacturing conditions (eg. daily or frequent differences in quality of raw ingredients or operations) but rather subtle changes to production equipment that emerge over a period of time (i.e. equipment wear and tear). The current single annual performance test required by both the federal and state greenhouse gas reporting programs has identified such equipment issues with Simplot's nitric acid plant in the past. The results of these performance tests and subsequent GHG reporting obligations have prompted quick action to replace and repair acid plant equipment not performing optimally.

Following repairs to effected nitric acid plant equipment in 2013, N₂O performance tests at Simplot have been consistent; accounting for less than 2000 tonnes or 25% of all GHG emissions from the facility for the past two reporting years.

As CARB is well aware, performance testing is both cost prohibitive and time consuming for facilities. In Simplot's experience, costs associated with N₂O source tests in particular range between \$10,000 to \$20,000 per test and require 3 days of staff time to plan, prepare and execute. In CARB's MRR staff report (Initial Statement of Reasons for Rulemaking), costs for complying with the proposed rule amendments for all general industrial sectors including nitric acid are reported to be \$47,242 over eight years

following implementation. If an additional performance test would be required for nitric acid facilities, Simplot's costs of compliance would range between \$80,000 to \$160,000 in the same timeframe. These costs far exceed CARB's estimates for all general industrial sectors combined to comply with the proposed amendments to the mandatory reporting regulation.

Given the limited magnitude that N₂O emissions represent of the GHG emissions from the overall nitric acid facility, under normal plant operating conditions it is Simplot's opinion that additional source testing will provide data of limited additional value or a higher degree of accuracy to CARB. As such Simplot requests that Section 95118 (e) not be added to the MRR. (SIMPLOT)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.9. Comment:

Verification Requirements

Staff proposes to change the verification deadline from September 1 each year, to August 1, to support implementation of the cap-and-trade program. CARB staff has cited insufficient time to perform required duties mandated under the cap-and-trade programs and that providing an additional month after the verification deadline allows ARB sufficient time to assess a compliance obligation to all covered entities, as well as calculate allowance allocation amounts, prior to the November 1 Cap-and-Trade Regulation compliance deadline.

As CARB staff notes in the Initial Statement of Reasons for the MRR:

"While the implementation of the change to the verification deadline may allow less time for reporting entities to verify their data, it will provide these entities more time to review their compliance obligation, assess how many allowances they receive, and make arrangements to acquire any additional compliance instruments needed for timely compliance." (page 10)

While this may not have much impact on covered entities operating year-round, food processors, due to seasonal operations, will be hard pressed to accommodate this change in the verification deadline. For food processors, this time change occurs in the middle of the processing season. Processors operate 24/7 for approximately 90 to 110 days beginning July through mid-October depending upon the product and the harvest.

Verification requires on-site inspections and frequent requests for data at the most intensive production time of the year. These difficulties are compounded by CARB's regulation requiring that covered entities must change verifiers every three years.

CARB staff needs to acknowledge the difficulties that this proposed change inflicts on food processors. CLFP wishes to work with CARB staff to develop criteria that will seek

to accommodate food processing operations allowing for a smooth verification without interference with production during this critical time.

One suggestion would be to allow food processors to contract with verifiers for six years instead of the current three. This would allow the verifier to become familiar with food processing operations and could expedite the verification process cutting back on the need for frequent data requests, additional CARB audits, and additional expenses. (FOODPROCESSORS)

Response: Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.10. Comment:

Accelerating the September 1 Deadline under the Mandatory Reporting Regulation to August 1 May Have Consequences on Data Quality and Compliance

Currently there are only 33 verifiers responsible for filing over 400 reports, all of which share the same September 1 deadline. While Calpine recognizes the rationale ARB has offered for moving the deadline to August 1, ARB should be aware of the potential implications of this change, both to the program and the regulated community.

Acceleration of the deadline poses several issues for covered entities and their verifiers, ranging from impacts to data quality to increasing the risk of unintentional noncompliance due to lack of qualified verifiers. These potential issues are exacerbated by the fact that the number of companies providing verification services has dropped precipitously in recent years and may continue to do so. For the initial reporting period in 2008, there were about 75 providers; there are now less than half that. The pool of verifiers is further limited by their expertise in specific sectors. We believe that the proposed compression of deadlines between submission of the emissions data report and verification of same may not allow adequate time for all intermediate steps to occur without complication. (CALPINE)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.11. Multiple Comments:

Based on Metropolitan's experience with the current C&T and Mandatory Reporting regulations, Metropolitan offers a comment regarding ARB's proposed changes to the verification deadline.

Metropolitan requests ARB not change the verification deadline from September 1st to August 1st. This change would create additional burdens to complete the verification process within a shortened timeframe by the new deadline. Presently, there are only a

small number of accredited verifiers from which to choose. ARB should encourage and develop a larger pool of accredited verifiers to support regulated entities. (MWD)

Comment:

MID strongly opposes moving the verification deadline from September 1st to August 1st. The Electric Power Entity (EPE) emissions report, which is due on June 1 of each year, is a complex filing that requires third parties to deliver data to EPEs before it can be accurately completed. ARB staff has stated in multiple stakeholder workshops that EPEs can simply begin the verification process earlier to ensure meeting the deadline. However, it has been MID's experience that the intensive nature of the data review and site visits required by the verification process does not allow for shorter verifications. the verification has been MID strives for timely compliance and typically begins its verification activities well before the deadline; however, the complexities of verifying the high volume of annual transactions often result in completion completed only a few days prior to the verification deadline, even when starting the process shortly after the reports have been submitted released for verification. Because compliance with the U.S. EPA's Clean Power Plan requires two-year compliance periods, the more time-intensive on-site verifications will be more frequent than they have been in the past⁵⁵⁷. Additionally, decreasing the amount of time in which verifiers can complete their tasks also potentially decreases the number of verifications that each verifier can perform. increased risk of non-compliance for some entities due to reduced verifier availability. MID recommends that the ARB strike language moving the verification deadline from September 1st to August 1st from the Proposed Regulation Order. (MODESTOID)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.12. Comment:

The amendment to §95105(d)(6) in Appendix A to the Staff Report would require entities claiming an RPS adjustment to explain how they determined that electricity claimed for the RPS adjustment was not directly delivered into California. EPEs can work with their contract counterparties to minimize and record direct deliveries to the extent possible, but may not have access to data from entities that do not have an obligation to share their confidential e-tag data, or have access to e-tags for downstream transactions. The e-tag data is the only means of determining the path of electricity from the original renewable resource to its sink. Without this information, an entity cannot be certain that all MWhs of electricity from their resource was not directly delivered and may lose the ability to claim an RPS adjustment. (MODESTOID)

⁵⁵⁷ An on-site verification must be performed by all entities during the first data year of a new compliance period.

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.13. Comment:

Regarding: Proposed changes to MRR Section 95104 (f) regarding independent verification of statements regarding increases or decreases in facility emissions.

Simplot believes that this language should remain as it is currently written and not be changed to require 3rd party verification of these statements. These statements are often subjective in nature and typically require detailed technical knowledge of plant operations to determine why emissions may have increased or decreased (eg. impacts of catalyst selection or operational temperature on formation of N₂O in nitric acid trains). Without substantial additional reporting or in-depth scientific analysis in some circumstances, Simplot does not believe that an independent 3rd party verification firm would be able to adequately assess the accuracy or inaccuracy of these statements. (SIMPLOT)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.14. Comment:

[WSPA submitted a flow chart that appears to describe their MRR compliance activities as a written comment at the September board hearing.] (WSPA)

Response: Since the commenter did not make a specific request, no response is needed.

O-1.15. Comment:

Calpine would also encourage ARB to consider improvements to the existing Cal e-GGRT system that would better assist with accurate reporting and verification. For example, several features could be added to the system to assist with reporting for individuals reporting on behalf of several facilities, such as batch review and certification for multiple facilities, removal of the redundant password request for each report certification, automatic data loading from the previous year's report, elimination of duplicate reporting from the various subparts, and the ability to upload one excel sheet for SF6 reporting for multiple LLCs. (CALPINE)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

V. SUMMARY OF COMMENTS MADE DURING THE 1ST 15-DAY COMMENT PERIOD AND AGENCY RESPONSES

Chapter V of this FSOR contains all comments submitted during the first 15-day comment period that were directed at the proposed amendments or to the procedures followed by ARB in proposing the amendments, together with ARB's responses. The first 15-day comment period commenced on December 21, 2016, and ended on January 20, 2017.

ARB received 70 letters on the proposed amendments (not including duplicates) during the first 15-day comment period. To facilitate use of this document, comments are categorized into sections, and are grouped by response wherever possible.

Table V-1 below lists commenters that submitted written comments on the proposed amendments during the first 15-day comment period, identifies the date and form of their comments, and shows the abbreviation assigned to each.

Note that some comments which follow were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>. Transcripts for any verbal testimony presented is available here: <https://www.arb.ca.gov/board/mt/2016/mt092216.pdf>.

A. LIST OF COMMENTERS

Table V-1

Abbreviation	Commenter
9UTILITIES	Tim Carmichael, 9 Utilities Written Testimony: 01/20/2017
ADHOCOFFSETS	Jon Costantino, Ad Hoc Offsets Group Written Testimony: 01/20/2017
AGCOUNCIL	Rachael O'Brien, Agricultural Council of California Written Testimony: 01/20/2017
AIRLIQUIDE	Jared Wittry, Air Liquide Written Testimony: 01/20/2017
BLOOMENERGY	Erin Grizard, Bloom Energy Written Testimony: 01/20/2017
BLUESOURCE	Kevin Townsend, Bluesource Written Testimony: 01/20/2017
CAISO	Andrew Ulmer, California Independent System Operator Corporation Written Testimony: 01/20/2017

Abbreviation	Commenter
CALCHAMBERCOMM ERCE	Amy Mmagu, California Chamber of Commerce Written Testimony: 01/20/2017
CALMUNIUTILASSOC	Justin Wynne, California Municipal Utilities Association Written Testimony: 01/20/2017
CALPINE	Kassandra Gough, Calpine Corporation Written Testimony: 01/20/2017
CALSTEELIND	Brett Guge, California Steel Industries Written Testimony: 01/20/2017
CCEEB	Jerry Secundy, California Council for Environmental and Economic Balance Written Testimony: 01/20/2017
CCPC	Shelly Sullivan, Climate Change Policy Coalition Written Testimony: 01/20/2017
CITYLONGBEACH	Diana Tang, City of Long Beach Written Testimony: 01/20/2017
CLIMACTRESERV	Mark Havel, Climate Action Reserve Written Testimony: 01/20/2017
CLIMATETRUST	Sheldon Zakreski, Climate Trust Written Testimony: 01/20/2017
CMTA	Michael Shaw, California Manufacturers & Technology Association Written Testimony: 01/20/2017
COVANTA	Michael Van Brunt, Covanta Written Testimony: 01/20/2017
CROCKETTCOGEN	Peter Weiner, Paul Hastings LLP on behalf of Crockett Cogeneration Written Testimony: 01/20/2017
CSCME	John Bloom, Coalition for Sustainable Cement Manufacturing & Environment Written Testimony: 01/20/2017
DIRECTENERGY	Read Comstock, Direct Energy Written Testimony: 01/20/2017
EIMENTITIES	Mary Wiencke, Energy Imbalance Market (“EIM”) Entities Written Testimony: 01/20/2017
EJAC	Environmental Justice Advisory Committee Written Testimony: 01/13/2017
FIRSTENV	James Wintergreen, First Environment Written Testimony: 01/20/2017
FOODPROCESSORS	John Larrea, California League of Food Processors Written Testimony: 01/20/2017
GALLO	John Nagle, E&J Gallo Winery Written Testimony: 01/20/2017

Abbreviation	Commenter
GLASSPACKAGING	Lynn Bragg, Glass Packaging Institute Written Testimony: 01/20/2017
GOLDENSTATEPOWER	Jessica Nelson, Golden State Power Cooperative Written Testimony: 01/20/2017
GRAPHICPACKAGING	Bill Buchan, Graphic Packaging International Inc Written Testimony: 01/20/2017
IETA	Katie Sullivan, International Emissions Trading Association Written Testimony: 01/20/2017
JOINTGASUTILS	Tim Carmichael, Gas Utility Group Written Testimony: 01/20/2017
LADWP	Jodean Giese, Los Angeles Department of Water and Power Written Testimony: 01/20/2017
LASANITATION	Frank Caponi, Los Angeles County Sanitation Districts Written Testimony: 01/20/2017
MODESTOID	Brock Costalupes, Modesto Irrigation District Written Testimony: 01/20/2017
M-S-R	Martin Hopper, M-S-R Public Power Agency Written Testimony: 01/20/2017
NAIMA	Angus Crane, North American Insulation Manufacturers Association Written Testimony: 01/19/2017
NCPA	Susie Berlin, Northern California Power Agency Written Testimony: 01/20/2017
NVENERGY	Lindsey Schlekeway, NV Energy Written Testimony: 01/20/2017
OFFICERATEPAYERADVCT	Diana Lee, California Public Utilities Commission / Office of Ratepayer Advocates Written Testimony: 01/20/2017
ONDAENERGY	Andy Friedl, Onda Energy Written Testimony: 01/02/2017
ORIGINCLIMATE	Nick Facciola, Origin Climate Written Testimony: 01/20/2017
PACIFICORP	Mary Wiencke, PacifiCorp Written Testimony: 01/20/2017
PANOCH	Robin Shropshire, Panoche Energy Center Written Testimony: 01/20/2017
PASADENA	Badia Harrell, Pasadena Water and Power Written Testimony: 01/19/2017
PG&E	Nathan Bengtsson, Pacific Gas and Electric Written Testimony: 01/20/2017
PORTLANDGENELEC	Elysia Treanor, Portland General Electric Company Written Testimony: 01/20/2017

Abbreviation	Commenter
POSCOINDUSTRIES	Suzy Hong, USS-POSCO Industries Written Testimony: 01/20/2017
POWEREX	Nico van Aelstyn, Beveridge & Diamond PC on behalf of Powerex Written Testimony: 01/20/2017
PRAXAIR	Armando Botello, Praxair Inc Written Testimony: 01/20/2017
PUGETSNDENRGY	Tom Flynn, Puget Sound Energy Written Testimony: 01/20/2017
SCPPA	Sarah Taheri, Southern California Public Power Authority Written Testimony: 01/20/2017
SEACITYLIGHT	Stefanie Johnson, Seattle City Light Written Testimony: 01/20/2017
SFPUC	James Hendry, San Francisco Public Utilities Commission Written Testimony: 01/20/2017
SILICONVALLEYPOWER	Steve Hance, City of Santa Clara/Silicon Valley Power Written Testimony: 01/20/2017
SMUD	William Westerfield, Sacramento Municipal Utility District Written Testimony: 01/20/2017
SOCAL Edison	Adam Smith, Southern California Edison Written Testimony: 01/20/2017
SOCAL GAS	Tim Carmichael, Southern California Gas Company Written Testimony: 01/20/2017
TESORO	Miles Heller, Tesoro Corp Written Testimony: 01/20/2017
TURLOCKID	Ken Nold, Turlock Irrigation District Written Testimony: 01/20/2017
UNIVCALIF	Nick Balistreri, University of California Office of the President, Energy and Sustainability Written Testimony: 01/20/2017
USBORAX	Nicol Gagstetter, U.S. Borax Written Testimony: 01/19/2017
VALLEYELECTRIC	Ellen Wolfe, Resero Consulting on behalf of Valley Electric Association, Inc. Written Testimony: 01/20/2017
WINDSET	Dillon Kass, Windset Farms Written Testimony: 01/18/2017
WONDERFUL	Melissa Poole, The Wonderful Company Written Testimony: 01/20/2017
WPTF	Clare Breidenich, Western Power Trading Forum Written Testimony: 01/20/2017

B. ALLOWANCE ALLOCATION

B-1. Electrical Distribution Utilities

Allocation Assumptions

B-1.1. Multiple Comments:

SCE is concerned with the rapid rate of decline in electric utility allocations due to the dual impacts of a significant cap adjustment factor and assumptions about utility compliance in the RPS Program. ARB staff has proposed a significant decrease in allowance allocation for EDUs from 2021-2030, which would directly reduce the biannual Climate Credit returned to customers, at a time when the state's climate policies desire to see an increase in the utilization of electricity as an end-use fuel. The current proposal entails a precipitous annual reduction in allocation of approximately 7-9% between 2021 and 2030 due to reliance on both a cap adjustment factor (CAF) and assumptions about a ramp up to a 50 percent RPS. Consequently, the SCE and the Joint-Utility Group recommend that the ramp from 33 to 50 percent RPS be removed from the allocation methodology.

As the JUG noted in the letter sent to Senior CARB officials on December 9th, the assumption that each EDU's compliance burden will be reduced by the ramp up to 50% RPS by 2030 is inappropriate when determining allowance allocations. This is because not all RPS eligible electricity will directly reduce an EDU's carbon obligation under the Cap-and-Trade program. The JUG's December 9th letter described three areas where the RPS program may not result in emission reductions at EDUs:

1. Up to 10 percent of the RPS target can be satisfied using unbundled renewable energy credits (RECs), which does not reduce the EDU's carbon obligation under the Cap-and-Trade program;
2. It is unclear that the RPS Adjustment, which can be claimed by the EDU's to reduce their compliance obligation for the 15%-25% of the RPS that can be met with Portfolio Content Category 2 resources and many grandfathered resources, will be fully available post-2020; and
3. RPS eligible electricity that is directly delivered to a California Balancing Authority area may not reduce an EDU's carbon obligation if the electricity is not delivered all the way to the EDU's service territory.

Additionally, further reducing EDU allocation because of the utilities' required investment in renewable resources is inappropriate given the expected customer cost burden from these resources and the cost of the associated infrastructure necessary to reliably deliver renewable electricity to our customers. These costs should be considered when determining the application of the RPS in the allocation methodology.

Finally, the way that RPS assumptions are applied in the proposed methodology is inconsistent with the manner in which the 2013-2020 EDU allocation was structured.

The EDU allocation in this period simply declined by the CAF, so that allocations to EDUs overall remained a consistent proportion representing about 25% of the total allowances as those declined over time. The proposed allocation structure in the 15-day language sharply departs from this, with EDU-sector allocation representing just 17% of all program allowances by 2030. Reducing allocation to EDUs disproportionately to the economy-wide decline in the cap does not recognize the important contributions that the electric sector is expected to make towards the State's overall GHG goals.
(SOCALEDISON)

Comment:

Program Transition

The new allowance allocation methodology is intended to provide allowances to the EDUs based on the cap-and-trade program cost burden faced by their electricity customers. The value of those allowances would be used exclusively for the benefit of the EDUs' electricity customers. Attachment C states that the cost burden is specific to the incremental cost of compliance with this Program:

"In developing the Regulation, ARB recognized that allocation to EDUs should "reflect the 'cost burden' associated with Program emissions costs that is anticipated to be borne by the ratepayers for each distribution utility" (ARB 2010B). Cost burden is the effect on ratepayers of the incremental cost of power to serve load due to the compliance cost for GHG emissions caused by the Program." (Attachment C, p. 2)

While similar in principle, the proposed allowance allocation methodology significantly reduces the number of allowances that are allocated to the EDUs for the benefit of their electricity ratepayers. In particular, the restrictive definition of cost burden that does not take into account the totality of EDU investments in carbon-free resources and underestimates the total cost burden to EDUs. This results in a significant decline in the allocation of allowances between 2020 and 2021 for some EDUs. This 2021 Allocation "Program Transition Cliff", or steep decline in allowance allocations is our foremost concern. For example, the Proposal would decrease allowance allocations between the year 2020 and 2021 by a shocking 64% for Anza Electric Cooperative. The "cliff" needs to be significantly mitigated because it is inconsistent with the allocation principles of consumer protection and avoidance of abrupt increases in consumer costs related to carbon pricing.

Additionally, many of the clean energy investments made by Cooperatives still have significant debt and costs associated with them, such as the large investment by Plumas-Sierra REC to build a high-efficiency cogeneration plant specifically designed and built to support the goals of AB 32. This plant has 10 years of principal and interest payments left in 2020. A dramatic decrease in allowance allocations impairs our ability to continue to invest in and construct clean energy resources.
(GOLDENSTATEPOWER)

Comment:

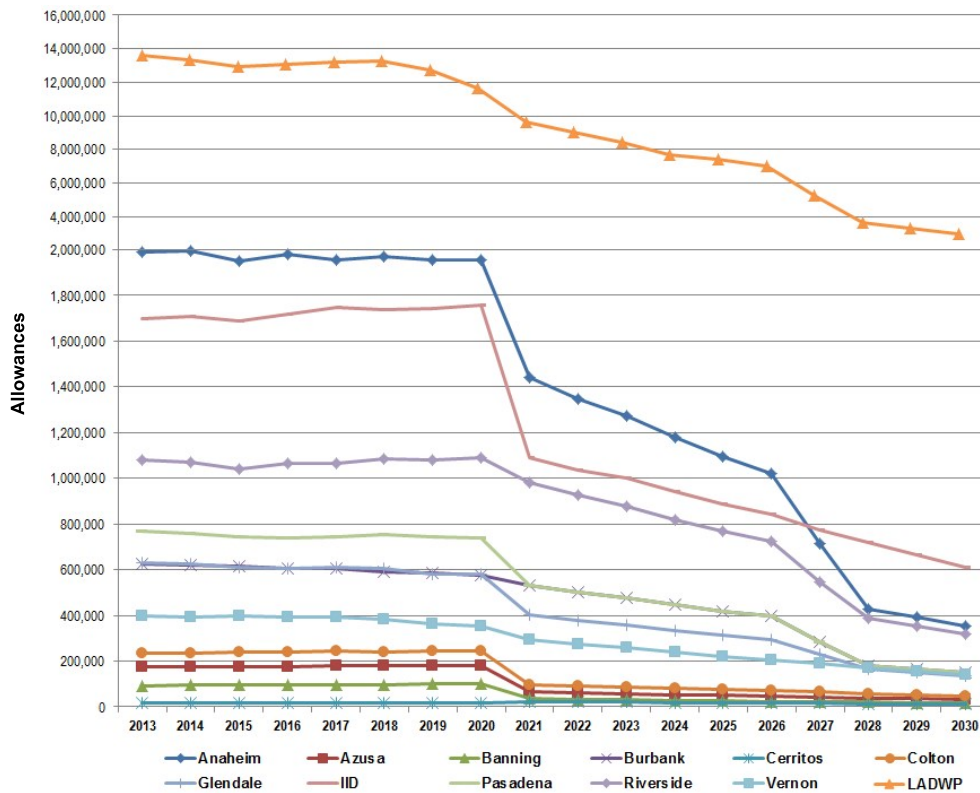
EDU Allowance Allocation Methodology. The ARB's proposed methodology for the allocation of allowances to electric distribution utilities (EDUs) is detailed in Attachment C in the Cap-and-Trade regulatory package. SCPPA and its members fully support ARB's proposal to base allocation on cost burden. We do, however, believe that the methodology could be further improved and offer comments on specific components of the methodology below.

Cost Containment. As noted above, SCPPA supports the proposed cost burden approach for determining allowance allocations. ARB staff shared its interpretation that cost burden should be based solely on implementation of the Program. We strongly urge ARB to consider the interactive effect of the Program with other state policies; in particular, the regulations should support efforts to minimize the overall cost impact to utility customers and avoid spikes or unnecessary increases in customer bills. Only with this holistic approach can the full cost impact of the State's policy goals be evaluated. Such an approach would provide a considerably more realistic view of the actual costs that POUs must pass down to customers as they work toward achieving emissions reduction targets while also addressing complementary policy goals such as electrification and an increasing Renewables Portfolio Standard.

Figure 1 below plots the trajectory for allowance allocations assigned to each SCPPA Member, showing the initial allocations in 2013 and extending out to the proposed 2030 allocations.⁵⁵⁸ For some of our Members, the significant decrease between 2020 and 2021 – and even further, the 2020 allocation as compared to 2030 – could potentially have large customer bill impacts when weighed with anticipated cost increases to reflect increasing renewable integration, electrification infrastructure, and a host of other state and federal mandates. ARB should promptly engage stakeholders in development of a meaningful cost containment mechanism. As further discussed below, developing a workable modification to allowance allocations that would accommodate increased load due to transportation electrification efforts is a strong example of a programmatic change that could help alleviate the sudden cost impacts felt in 2021.

⁵⁵⁸ This chart is based on allowance allocation data available on ARB's website. 2013-2020 data is drawn from [this](#) allowance allocation table, posted in February 2015, while 2021-2030 data is taken from the [—2021-2030 EDU Allowance Allocation Spreadsheet](#) posted on December 21, 2016.

Figure 1: SCPPA Member Allowances [2013-2030]



(SCPPA)

Comment:

A. ARB Should Solely Utilize the Cap Adjustment Factor to Avoid Double Counting GHG Emissions Reductions

First, ARB's proposal to adjust year-to-year EDU allocation for 2021-2030 by both the general cap adjustment factor (CAF) and the key electricity sector GHG reduction measure (obligation to achieve 50 percent RPS by 2030) results in an allocation decline that is too steep to adequately address EDU cost exposure and shield California households from higher annual electricity bills.

ARB staff maintain that the CAF is included to "equitably spread the effects of the declining cap across entities, and to spread them across years to encourage continually decreasing emissions."⁵⁵⁹ In addition, the 50 percent RPS is widely understood as a key measure to reduce electric sector GHG emissions to help achieve the statewide 2030 GHG target.⁵⁶⁰ As staff recognize, this will clearly reduce the EDU cap-and-trade cost burden as defined by ARB. However, by including the general reduction (the CAF) in addition to the reductions from the ambitious electric sector reduction measure (50

⁵⁵⁹ Attachment C: <https://www.arb.ca.gov/regact/2016/capandtrade16/attachc.pdf>

⁵⁶⁰ 2030 Target Scoping Plan Update Discussion Draft (p. 34): https://www.arb.ca.gov/cc/scopingplan/2030target_sp_dd120216.pdf

percent RPS), ARB is effectively not acknowledging RPS compliance as a strategy for accommodating the CAF.

As a result, the proposed EDU allocation is below the expected EDU cost burden as calculated by ARB. The EDU sector is the only sector in which this double-reduction is incorporated into the proposed allocation provisions. This is inequitable, and is a major driver of the steep decline, approximately 50 percent from 2021 to 2030, in the EDU allocations.

To address this affordability and equity issue, PG&E encourages ARB to utilize only one source of decline in the allocation methodology –the general decline as reflected in the CAF, assuming a flat 33 percent RPS in the allocation spreadsheet. Finally, we note that incorporating this change to the allocation provisions will not undermine EDU incentives to continue to reduce GHG emissions.

B. The Rapid 2020-2021 Allocation Decline Will Impact California Utility Customers if Not Addressed

Second, the transition between the 2020 allocation and ARB's proposed 2021 allocation is still too steep (approximately a 20 percent decline in one year for the overall EDU sector), despite some improvements due to the technical fixes already described. While ARB's Attachment C recognizes a major driver of the decline is a change in the load forecast, we note that EDU customer investments – in rooftop solar and energy efficiency – are key drivers of the downward shift in the load forecast. ARB is using a narrow definition of cost-exposure in describing potential over-allocation to EDU customers. We encourage ARB to consider the broader set of costs EDU customers are paying to help California achieve its GHG goals – including customer programs and the RPS program – in assessing fair allowance allocation levels.

In addition, the drop in allocation from 2020-21 will clearly reduce the size of California climate credits, and so increase the net annual electric bills of EDU customers. This effect, rather than the “rate shock” dismissed by ARB in Appendix C, is the one we seek to avoid in smoothing the transition from the 2020 to post-2020 allocation provisions. PG&E encourages ARB to include a transition mechanism that would increase the EDU allocations above the proposed levels. For example, ARB could reduce the allocation decline included in this proposal in 2021 relative to the 2020 quantities by 50 percent for each EDU, and then implement the CAF calculation to extend the 2021 values through 2030 (while still including adjustments for major changes to resources such as coal and nuclear), or for at least the fourth compliance period. (PG&E)

Comment:

The very sharp annual decline in allowances to EDUs, on the order of 7-9 percent per year, should be significantly lessened. The rapid decline occurs due to reliance on both the cap adjustment factor (CAF) and assumed impact of the linear ramp of RPS percentages from 2021-2030, and results in a decline at about twice the rate than

application of the cap alone -- the decline established for other allocated sectors of the California economy. For the reasons below, SMUD strongly recommends that ARB remove the linear ramp up to 50% RPS in the allocation, keeping the assumed RPS percentage at 33%, thereby removing this rapid decline. SMUD also suggests that the ARB consider establishing a revised CAF for the electricity sector, declining at a lower rate than the general CAF.

SMUD contends that the emission reductions that are expected by the increase to a 50% RPS duplicate the emission reductions that are signaled by the application of the CAF. It is sufficient to reflect these expected emission reductions in allocations only once. That the decline is much too severe is evidenced in the 2021-2030 EDU Allocation spreadsheet from ARB, which shows that the proposed allocation in the 15-day language falls further and further below the expected emissions in that spreadsheet, so that allocations amount to only 60% of expected emissions by 2030. This clearly is inconsistent with the underlying allowance allocation concept in the structure – that of reflecting the EDU cost burden of Cap and Trade.

In addition, the assumption that GHG emissions will be reduced in lock step with increasing renewables for the RPS is inappropriate and should not be used to determine allowance allocations. In fact, not all RPS eligible procurement will automatically and directly reduce an EDU's emissions under the Cap-and-Trade program. There are three types of RPS procurement that may not result in emission reductions under Cap-and-Trade. First, up to 10 percent of the RPS target can be unbundled renewable energy credits (RECs), which do not reduce carbon emissions for the procurer under the Cap-and-Trade program. Second, it is unclear that the RPS Adjustment, which can be claimed to reduce the compliance obligation to reflect certain RPS procurement, will be fully available post-2020. Third, even Product Content Category 1 RPS eligible electricity, which is directly delivered to a California Balancing Authority, does not reduce GHG emissions under Cap-and-Trade for the procurer when the electricity is not delivered all the way to the EDU's service territory.

Finally, the way that the RPS path is applied in the proposed methodology to reduce allocations to EDUs is inconsistent with the manner in which the 2013-2020 EDU allocation was structured. The electric sector allocation in this period simply declined by the cap factor, so that allocations to EDUs overall remained a consistent proportion representing about 25% of the total allowances as those declined over time. The proposed allocation structure in the 15-day language departs sharply from this, representing just 17% of overall allowances by 2030. The electric sector can and will make GHG emission reductions, but will also contribute reductions in other sectors via electrification activities, increasing EDU emissions. Reducing allocations to EDUs disproportionately to the overall decline in the cap does not recognize the important contributions that the electric sector is expected to make towards the State's overall GHG goals. (SMUD)

Comment:

The annual rate of reduction for EDU allowance allocation is too steep and would expose ratepayers to significant cost burden. MID appreciates that the allowance allocation calculations included in the 15-Day Changes apply the RPS program requirements to retail sales instead of total energy to serve load, which corresponds to how the RPS program works. However, certain aspects of the RPS program would make a linear ramp-up from 33% of EDU load served by renewable resources in 2020 to 50% in 2030, as shown in the calculations for allowance allocation, likely understates actual RPS program emissions reductions.

ARB's allocation methodology assumes that the RPS percentages (increasing annually in a linear fashion from 33% to 50%) of an EDU's retail electricity sales will be entirely served by non-emitting resources. In reality, the RPS program allows for several actions to be taken towards an EDU's RPS compliance that do not result in emissions reductions for that EDU; such as:

1. Ten percent of an EDU's RPS compliance can be satisfied by retiring unbundled Renewable Energy Credits (RECs), which represent emissions reductions elsewhere than the EDU's service territory.
2. The ability to bank RECs received through excess generation from RPS-eligible resources to satisfy RPS requirements in future compliance periods allows the EDU the flexibility to defer procurement of new renewable resources, providing an option for the EDU to avoid unnecessary additional costs to its ratepayers.
3. The RPS program allows firmed and shaped energy contracts, for which an out-of-state renewable facility generates energy that is blended with or replaced by unspecified energy that is then delivered to the EDU comprise up to 15% of an EDU's RPS obligation; however, grandfathered contracts of this type are also allowed by the RPS program, increasing that percentage. MID, for example, currently covers over 40% of its RPS obligation with grandfathered resources. MID and other EDUs that are parties to firmed and shaped contracts rely on the Cap-and-Trade program's RPS adjustment provision to avoid a compliance obligation for the renewable energy purchased from these facilities. The current rulemaking has introduced an increased burden of proving that the replacement energy associated with these contracts has not been delivered into California, which is a requirement to claim an RPS adjustment. For any energy for which the EDU will be unable to claim an RPS adjustment, the EDU will have a compliance obligation that is assumed not to exist by the current allowance allocation methodology. For MID this may represent approximately 40% of the energy from our out-of-state, RPS-eligible resources.

These actions that are allowed by the RPS program still result in a positive effect on the environment, but may result in the EDU's load being served by emitting rather than renewable resources and would have an associated compliance obligation that is not contemplated by ARB in the allocation methodology included in the 15-Day Changes.

While this understatement of EDU emissions is harmful to ratepayers on its own, the fact that the linear increase from 33-50% RPS is combined with the Cap Adjustment Factor (CAF) creates a very damaging impact to allowance allocation for ratepayer protection. The proposed allocation calculated by ARB for MID decreases annually by 6% from 2021 to 2022 and increases each year until it reaches a significant 9% reduction from 2029 to 2030. MID recognizes ARB's desire to transmit a price signal through electricity rates to incentivize reduced consumption; however, the proposed allocation schedule would result in compliance costs that are too high. The allowance allocation calculations included with the 15-Day Changes forecast that 26% of emissions over the 2021-2030 period would be unallocated for, with those compliance costs passed through to MID's ratepayers. As the emissions cap decreases annually the uncovered cost burden increases, with 44% of the cost burden unallocated for in 2030. MID contends that this amount of uncovered cost burden goes far beyond an economic price signal and does not sufficiently meet the allowance allocation goal of protecting ratepayers from excessive and harmful compliance costs.

MID endorses the solution proposed by the Joint Utilities Group, in which the allowance allocation calculation holds the RPS requirement at 33% rather than increasing linearly from 33% in 2020 to 50% in 2030. The CAF alone sufficiently performs the function of guiding the EDU sector towards decreasing emissions and is sufficiently steep to encompass the emissions reductions realized through participation in the RPS program. There is no need to duplicate this function with the linear RPS ramp. This solution would result in a much more reasonable 2-5% annual decrease in allowances.
(MODESTOID)

Comment:

RPS Adjustment: The RPS Adjustment is intended to reduce an EDU's compliance obligation by ensuring that deliveries of RPS-eligible resources are not counted as part of the compliance obligation. When an EDU utilizes the RPS adjustment, the share of zero-GHG resources reflected in their RPS portfolio is accurately reduced for purposes of calculating the cap-and-trade program compliance obligation. However, to the extent that accounting and tracking for those resources precludes an EDU from utilizing the RPS Adjustment, a cap-and-trade program compliance obligation is assigned to resources that are not counted toward the EDU's compliance burden under the current proposal.

The cap-and-trade program should align to the greatest extent possible with other climate programs, and in particular when those other programs define and influence the policy direction of the cap-and-trade program as the RPS mandate does in this instance. As the above examples clearly demonstrate, by 2030, EDUs may be 100% compliant with their RPS mandate, but not necessarily be serving 50% of their retail load with non-RPS resources during that RPS compliance period; meaning that those resources would have a cap-and-trade compliance obligation that adds to the EDU's cap-and-trade program cost burden that is not recognized in the number of allowances

allocated to the EDUs. Because this can occur for several reasons that were clearly recognized by the legislature when the program was designed, and these factors should likewise be recognized in the allowance allocation calculation. Accordingly, to address these statutory provisions and ensure that the cap-and-trade program accurately recognizes these aspects of the state's RPS mandate, the 50% straight line RPS trajectory should be adjusted.

Since the cap adjustment factor already applies a rate of decline that actually compounds the impact of the increasing RPS mandate relative to the calculation of allowance allocation, NCPA recommends that the RPS mandate be reflected in the allowance calculation by using a 33% trajectory through to 2030. Such a change is absolutely critical to appropriately address the cost burden of the climate program to California consumers. (NCPA)

Comment:

PacifiCorp does, however, continue to have concern with respect to the significant reduction in allowances from 2020-2021. Though this change may not result in rate shock as that term is typically used, it may significantly impact customers who have come to rely on a certain level of climate dividend each year. It is reasonable to provide some mechanism to ease or transition this change so that it is not done so dramatically over the course of one year. PacifiCorp supports the proposals set forth by the Joint Utility Group to ease this burden on customers and increase the transparency and fairness with which the allocations were developed. (PACIFICORP)

Comment:

TID will be experiencing a drastic and sudden reduction in allowances. From 2020 to 2021, a 55% reduction, and from 2020-2030 a nearly 80% reduction in the amount of allowances allocated. In order to avoid rate shocks to EDU customers, the ARB should implement a phased in approach to allowance allocation, starting with the 2020 allocation, and phasing in additional allowances down to the proposed 2021 allocation in 2024. A supplemental "phase in" allocation will help ameliorate the substantial rate shock that may result from the substantial reduction in allowances in the post-2020 program. Due to TID's disadvantaged rate base, the substantial reduction in allocations will harm the very ratepayers that the Program and the EDU allocation rules are designed to protect. Since such a large percentage of TID's ratepayers are in disadvantaged communities, it will be difficult if not impossible to isolate and protect against rate impacts for these customers. The result of such rate increases will contradict the legislative intent behind AB 197, which is to minimize impacts on disadvantaged communities. TID expects the overall impacts to ratepayers to vary significantly and plans to file supplemental comments in this rulemaking with our anticipated cost impacts. To avoid these impacts the ARB should provide a transition to the new allocation levels in the first full compliance period of the post 2020 program. (TURLOCKID)

Comment:

SMUD appreciates the continued administrative allocation of allowances to electric distribution utilities (EDUs) on behalf of their ratepayers, as described in workshops leading up to the Proposed Amendments (the detailed allocation structure is not yet included in the regulatory language). SMUD supports the continuation of the “cost-burden” concept for allowance allocation structure that underlies the proposal by ARB staff in the 15-day language, but is deeply concerned that the 15-day language proposal falls far short of covering EDU emissions and cost burdens. SMUD cannot support the structure as proposed, without changes that provide allowances in a manner that truly is consistent with cost burden.

Without the changes requested below, it is fairly clear that SMUD and other EDUs will increasingly have insufficient allowances allocated to cover their emissions, resulting in significant ratepayer costs on top of the costs ratepayers already incur for complementary measures to reduce GHGs, such as renewable procurement and energy efficiency costs. CARB’s 2021-2030 EDU Allocation spreadsheet that accompanied the 15-day language shows SMUD’s 2030 “projected” emissions at just over 2 million tons, and provided allowances to cover only 1.2 million of these tons, a shortfall of approximately 800,000 tons.

Using these CARB values and the range of expected carbon prices in the economic analysis of the Draft 2030 Scoping Plan implies that SMUD customers would be faced with an additional \$20 – \$64 million cost burden for carbon costs in 2030. A major drought at the time could essentially double the shortfall as hydro resources produce less power, implying potential ratepayer costs of \$40-\$132 million in that year. Linearly interpolating the allowance prices above and applying them to the annual shortfall in CARB’s spreadsheet, yields potential ratepayer costs of \$100 to \$400 million between 2021 and 2030. As other EDUs are treated relatively similarly in CARB’s methodology, and SMUD represents about 5% of the utility sector, the overall ratepayer cost burden is on the order of \$2 billion to \$8 billion dollars.

These are obviously very significant potential ratepayer impacts, affecting all of our customers. These additional costs are hardest to absorb for SMUD’s lower income customers and those already affected by living in disadvantaged communities. In addition, such a shortfall in allowances removes any chance that SMUD will continue funding programs using surplus AB 32 allowance revenue. Currently, SMUD allocates about \$3 million a year in such revenue for programs to reduce GHG emissions in our service territory, including programs focused on low-income customers and disadvantaged communities. For example, SMUD has used these funds for three different programs over three years to target deep energy efficiency retrofits at low-income customer homes...

SMUD contends that the dramatic change in allowance allocations from the end of the current structure in 2020 to the beginning of the 2021-2030 structure should be

mitigated by at least a four-year “phase-in” from one structure to the next. This is accomplished by simply drawing a straight line between the current 2020 allocations for each EDU and the proposed allocation for 2024 (or later year), thereby allowing commercial adjustment to the significant change in revenues that this represents.

Without this adjustment, EDUs will see a sharp drop in allowances provided in 2021, which will lead to either a sharp increase in ratepayer costs (in the form of higher rates or higher bills, or both) or a sharp decrease in GHG-reducing program budgets. EDUs try to avoid such rate/cost shocks and disruptions in program budgets, as they tend to aggravate ratepayers and undermine program success.

SMUD understands that one reason for the sharply lower allocations beginning in 2021 is that the most recent statewide retail sales forecasts for the decade 2021-2030 are lower than those used for the 2013-2020 allocations. Two main reasons for these lower forecasts are the significant investments in energy efficiency programs and distributed generation resources made by the EDUs and their customers. SMUD suggests that this success should be recognized by phasing in the change in allocation structure. Such recognition would protect ratepayers against the possibility that actual load exceeds the load projections and would represent an incentive to continue, or even expand, these GHG-reducing programs, particularly in the latter half of the 2020s. The expectation by EDUs that efficiency and other GHG-reducing investments will be accompanied by a loss of allocations on an ongoing basis should be avoided. (SMUD)

Comment:

Turning to specific impacts on NCPA members, Table 1 indicates that moving to a 33% trajectory to 2030 provides an additional 2.2 million allowances for NCPA members. Such a change provides at least \$50 million in cost burden protection to the nearly 700,000 customers served by NCPA member utilities. This estimate is actually conservative, assuming that the carbon price remains at the floor without any inflation adjustments throughout the ten-year period. To properly bound the range of potential relief, we also assumed that carbon prices rise to the Allowance Price Containment Reserve of \$60, NCPA the cost burden protection increases to \$131 million. If inflation is factored into the equation, the range of costs will increase even further.

Table 1

Allowance Allocation Estimates Under Different Scenarios

NCPA Members 2021-2030

33% RPS Factor Throughout											
NCPA Member	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Alameda	72,498	69,101	65,855	62,611	59,399	56,252	53,877	51,187	48,464	45,617	584,862
Biggs	2,495	2,388	2,283	2,179	2,075	1,972	1,885	1,795	1,702	1,605	20,379
Gridley	5,826	5,606	5,385	5,164	4,943	4,719	4,490	4,272	4,052	3,820	48,277
Healdsburg	19,194	18,451	17,828	17,110	16,462	15,809	14,922	14,169	13,407	12,612	159,964

Lodi	106,247	102,221	98,503	94,831	91,117	87,435	82,600	78,417	74,189	69,780	885,341
Lompoc	33,291	31,895	30,576	29,230	27,902	26,583	25,286	24,003	22,707	21,356	272,831
Port of Oakland	20,622	19,970	19,279	18,603	17,886	17,176	16,213	15,391	14,561	13,695	173,396
Palo Alto	149,557	142,618	136,298	130,013	123,332	116,837	112,119	106,743	101,272	95,520	1,214,308
Roseville	311,337	304,050	294,690	284,507	274,786	264,281	251,080	240,354	229,286	217,447	2,671,818
Shasta Lake	60,046	57,952	56,332	54,265	52,152	49,992	47,519	45,363	43,156	40,817	507,594
Ukiah	27,494	26,443	25,304	24,134	23,082	21,924	20,886	19,829	18,761	17,646	225,502
Plumas-Sierra	27,310	26,092	24,845	23,622	22,493	21,232	20,383	19,392	18,385	17,329	221,083
Redding	139,279	136,167	132,948	129,119	125,080	120,941	114,913	110,558	105,988	101,002	1,215,995
Silicon Valley Power	673,826	652,757	630,443	605,986	580,204	554,228	526,278	500,098	473,582	445,855	5,643,258
Truckee Donner PUD	49,329	47,636	45,915	44,165	42,387	40,580	38,897	37,012	35,098	33,089	414,109
NCPA Total	1,698,352	1,643,348	1,586,485	1,525,542	1,463,302	1,399,960	1,331,348	1,268,582	1,204,609	1,137,189	14,258,717
Original CARB Proposal											
NCPA Member	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Alameda	71,138	65,199	60,891	55,522	50,417	46,676	42,697	38,655	34,795	31,060	497,051
Biggs	2,432	2,208	2,054	1,850	1,658	1,526	1,366	1,212	1,067	929	16,302
Gridley	5,683	5,192	4,857	4,406	3,977	3,684	3,287	2,925	2,582	2,254	38,847
Healdsburg	18,877	17,526	16,648	15,398	14,288	13,485	12,216	11,135	10,098	9,088	138,759
Lodi	104,487	97,137	91,981	85,426	79,083	74,471	67,618	61,623	55,873	50,274	767,971
Lompoc	32,751	30,341	28,590	26,382	24,278	22,701	20,774	18,946	17,192	15,482	237,438
Port of Oakland	20,285	18,995	18,025	16,791	15,568	14,676	13,327	12,155	11,031	9,936	150,789
Palo Alto	145,720	131,598	122,250	109,902	97,836	89,633	80,381	71,166	62,471	54,195	965,152
Roseville	305,836	288,054	274,058	254,635	236,488	222,959	203,101	186,228	169,876	153,769	2,295,004
Shasta Lake	59,231	55,572	53,267	49,832	46,466	43,854	40,395	37,325	34,333	31,360	451,635
Ukiah	27,026	25,097	23,571	21,632	19,904	18,497	16,919	15,382	13,911	12,482	194,421
Plumas-Sierra	26,670	24,241	22,470	20,198	18,145	16,554	14,959	13,312	11,754	10,267	178,569
Redding	135,822	126,108	119,980	110,353	100,997	94,962	84,752	76,532	68,637	60,965	979,108
Silicon Valley Power	660,892	615,292	582,321	536,773	491,946	459,538	416,425	376,956	339,275	302,812	4,782,230
Truckee Donner PUD	48,702	45,821	43,585	40,807	38,095	35,962	33,536	30,984	28,502	26,041	372,037
NCPA Total	1,665,552	1,548,382	1,464,546	1,349,907	1,239,145	1,159,178	1,051,754	954,537	861,397	770,913	12,065,312

Clearly, the level of protection will fall somewhere within the ranges depicted in Table 1. As these numbers evidence, the potential impact is not *de minimus* and irrespective of the actual number, in all cases it is important to note that the vast majority of this added protection will occur after 2025, at exactly the time when cost protection is solely needed and uncertainties surrounding reaching the 2030 goal will be greatly tested.

Applying a 33% RPS trajectory through to 2030 better recognizes the EDU cost burden. Furthermore, doing so still ensures that the EDUs will continue to reduce overall emissions, but better aligns these two climate programs, and protects electricity ratepayers from an unwarranted additional cap-and-trade cost burden because of the RPS program.

2. Customer Impacts of the EDU Cost Burden

An overriding concern for NCPA is the ultimate impact that the increased reduction mandates and associated program compliance costs will have on the electricity customers of NCPA's member agencies. The proposed definition of the EDU cost

burden does not reflect the true cost of compliance for EDUs, as it does not address the full range of emission reduction mandates that electricity customers are ultimately responsible for funding. As CARB notes, allowances are allocated to EDUs “because EDUs have direct relationships with retail customers. These relationships put EDUs in a position to use allocated allowances to benefit retail customers consistent with AB 32 goals.”⁵⁶¹

EDU compliance costs will continue to increase under the tightening emissions cap and increasing reduction mandates from other programs. Increased compliance costs results in increased electricity costs. The post-2020 cap-and-trade program is not merely a continuation of the current program, but one that includes a significant reduction in the total emissions cap. As such, it is entirely appropriate for some actions taken after initiation of the cap-and-trade program to be recognized as part of the cost burden, and “early actions” must be viewed in the context of the current program and the changes inherent in continuation of the program post-2020. The key principles upon which the preliminary EDU allowance allocation was based included covering the distribution utilities’ compliance cost burden, energy efficiency, and recognition of early investments.⁵⁶² Those early investments included emission reductions beyond those required of the EDUs at that time. In the context of the current program, many EDUs continued to make investments in emissions reductions beyond those that were mandated. Indeed, such investments were encouraged.⁵⁶³ However, under the allocation proposal described in Attachment C, those investments are not recognized as part of the continuation of the cap-and-trade program. This is despite the fact that the post-2020 program connotes a new era of emissions reductions, including an even lower emissions cap that declines more rapidly than under the current program. The “EDUs’ cost burden for transitioning to lower or non-GHG emitting resources and engaging in load reduction measures should be properly recognized in the context of the Program.”⁵⁶⁴ EDUs that made investments in cleaner portfolios – such as through agreements to divest from coal-fired resources, purchases of additional renewable resources, or investments in energy efficiency – furthered the objectives of AB 32. Those investments may result in decreased cap-and-trade program compliance costs, but are not necessarily less costly to electric ratepayers than surrendering allowances.

Due to the differences in the way the allocations are calculated for 2021 to 2030, some EDUs will have a significant decrease in allocated allowances between 2020 and 2021, which will cause a corresponding increase in the electricity rates. The failure to recognize the impact of post-2020 investments in emissions reductions and the steeper rate of decline included in the proposed cap adjustment factor are key factors resulting

⁵⁶¹ Attachment C, p. 1.

⁵⁶² 2011 FSOR, P. 575

⁵⁶³ The 2011 FSOR repeatedly notes that the allocation system “will encourage continued investments in efficiency and clean energy in the future.” See, for example, p. 229, 230, 233, 1071.

⁵⁶⁴ NCPA September 19 comments.

in this “2021 cliff.” However, it appears that the true impacts of 2021 cliff and concern about the rapid escalation in compliance costs are not fully understood, as evidenced by Attachment C. In Attachment C, this potential rate shock is dismissed by suggesting that EDUs can plan for this event by “banking auction proceeds, passing the GHG cost through to their customers, and returning auction proceeds to ratepayers in a non-volumetric manner.”⁵⁶⁵ This suggestion, however, does not entirely address the problem for several reasons. For one thing, there is no way to pass along a “future” carbon cost to customers based on current carbon prices. Further, banking allowance value means that such value cannot be used to continue to fund existing emissions programs and measures, creating a shortfall in the near term. In order to protect ratepayers from the impacts of the updated cap-and-trade program, NCPA urges CARB to include a means to “smooth” this cliff. NCPA believes that this can be done, at least for an transition period, by recognizing EDU investments in additional carbon reduction practices that contributed to the 2020-2021 differential. Doing so ensures that some portion of those investments are recognized within the context of the cost burden, decreasing the 2021 cliff and the associated detrimental impacts on electricity customers. (NCPA)

Comment:

B. The Revised Cost Burden Results in Rate Increase for EDU Customers

The post-2020 cap-and-trade program does not simply continue the existing program, just as the allocation proposal does not simply duplicate what was done in 2013. The increased reductions mandated post-2020, coupled with changes to the overall allocation methodology results in the potential for significant rate increases for electricity customers beginning in 2021. This is due to the fact that those changes will result in a substantial reduction in the number of allowances received by some EDUs between 2020 and 2021. M-S-R believes that this “cliff” should be adjusted to minimize the cost impacts for electricity customers. One way to address this concern is to recognize the true nature of the continuation of the cap-and-trade program, the accelerating cap decline, and post-cap-and-trade investments in expanded emission reductions (including early divestiture of coal-fired resources). M-S-R joins with the other stakeholders that urge CARB to “look at the totality of the measures EDUs are required to implement to reduce statewide emissions, and not consider the Cap-and-Trade program in a vacuum. Rather, the cost burden should be considered in the context of the Scoping Plan itself. This is critically important because EDU costs associated with these other programs have a direct impact on their compliance obligation under the Program. Reduced compliance costs associated with the Capand-Trade Program do not necessarily translate to a reduced cost burden for EDUs.”⁵⁶⁶

When these costs are not accounted for, there is the potential for significant rate impacts beginning in 2021, when fewer allowances are provided to meet program costs.

⁵⁶⁵ Attachment C, p. 3.

⁵⁶⁶ M-S-R Public Power Agency Comments on Proposed Amendments to Cap-and-Trade Program , dated September 19, 2016 ([M-S-R September 19 Comments](#)).

CARB appears to dismiss this concern, noting that POUs and electric cooperatives can “plan ahead for the decrease in allocation by banking auction proceeds, passing the GHG cost through to their customers, and returning auction proceeds to ratepayers in a non-volumetric manner.”⁵⁶⁷ This recommendation, however, does not address the fact that investments in carbon reducing measures drive the lower allocation under the current definition of cost burden. Neither does the recommendation to bank allowance value account for how existing programs and measures that were created to reduce GHG emissions will be funded. The impacts of the “cliff” and the resulting rate shock to electricity customers is better addressed by recognizing these additional costs, at least during a transition period, so that customers can be shielded from the “sudden increases in their electricity bills associated with the cap-and-trade regulation.”⁵⁶⁸ (M-S-R)

Comment:

50% RPS Assumption within the Allocation Methodology. The proposed allowance allocation methodology assumes a straight-line path to a 50% RPS by 2030. While we appreciate the modifications to better align the Cap-and-Trade Program with the RPS Program (i.e., adoption of a retail sales-based approach), this is one assumption that does not adequately acknowledge the CEC’s RPS Program construct. It is imperative ARB recognize that a 50% RPS does not directly translate to a utility having 50% of its portfolio comprised of zero-emitting resources; ARB should adopt modifications that reflect this reality. The current proposed methodology creates unnecessary additional reductions in allowance allocations. We strongly encourage ARB to consider the nuances of the RPS Program that base utilities’ RPS targets on their historical contractual obligations and ability to procure unbundled Renewable Energy Credits (RECs). The CEC’s RPS Program permits utilities to account for up to 10% of their RPS obligation using these unbundled RECs, which allow for purchasing the renewable attributes of a renewable source without necessarily delivering that resource to customers. Ultimately, ARB should ensure that any RPS assumptions adopted for calculating allocations do not require utilities to exceed the currently in-effect state mandates. (SCPPA)

Comment:

2021-2030 EDU Allocation Proposal and Methodology:

The principle function of the EDU allocation is to mitigate the greenhouse gas (GHG) cost burden to utility ratepayers, consistent with AB 32 goals. EDU’s were allocated allowances to reduce the cost burden on ratepayers from the electricity price increase as a result of the expense of carbon. Originally, allowances were allocated equivalent to around 97% of an EDU’s expected obligation, then the allocation was reduced by approximately 3% per annum. Now, with the passage of SB32, the Cap and Trade

⁵⁶⁷ Attachment C, p. 3.

⁵⁶⁸ See October 2010 Initial Statement of Reasons, p. 11-28.

Program has been extended to implement additional GHG reduction goals; for this reason, the 2021 allocation should also represent a gradual transition. However, PWP's proposed 2021 allocation is 17% lower than 2020...

Renewable Portfolio Standard (RPS) Factor to Retail Sales:

CARB staffs decision to use retail sales as the basis for the RPS procurement target is appropriate and consistent with the California Energy Commission's (CEC) procurement requirement calculation. Yet, the proposed allowance allocation methodology excludes key considerations:

1. The proposed allowance methodology does not account for the CEC's allowable procurement of unbundled Renewable Energy Credits (RECs) to the maximum of 10% annually.
2. By assuming that the RPS requirement is met by bundled renewables only, the specific EDU cost burden is understated.

Revising the allowance allocation approach to include the procurement of unbundled REGs to meet an EDU's RPS requirement is consistent with SB 350 legislation and the CEC's RPS procurement policy. (PASADENA)

Comment:

Appropriately Calculating the RPS Mandate

CARB's allowance allocation methodology applies a straight-line reduction to the number of allowances allocated based on the "assumption that each EDU procures RPS-eligible power that increases from the mandated 33 percent in 2020 to 50 percent in 2030."⁵⁶⁹ Staff determined the EDUs annual RPS requirement by applying a linear path from the 33% of retail sales in 2020 to 50% of retail sales in 2030.⁵⁷⁰ In responding to stakeholder comments regarding the application of the RPS mandate, Attachment C states that "Staff proposed that the EDU allocation reflect increasing purchases of renewable electricity with SB 350 RPS requirements because this factor significantly reduces the Program cost burden. Staff believes that calculating annual cost burden must account for the significant decrease in cost burden that is associated with increasing renewable electricity purchases."⁵⁷¹ NCPA does not dispute that cap-and-trade program compliance costs for EDUs are directly impacted by the percent of the utility's customers served by renewable energy resources. However, staff's proposal is based on the erroneous assumption that the 50% RPS mandate set forth in SB 350 equates to the equivalent of 50% carbon-free resources in 2030. This is simply not the case.

⁵⁶⁹ Attachment C, p. 5.

⁵⁷⁰ *Id.*

⁵⁷¹ Attachment C, p. 4.

Basing allowance allocation on a straight-line trajectory to 50% does not accurately reflect the true level of zero-emission resources that can be used to meet the RPS mandate. There are provisions in SB 350 that recognize that, for each compliance period, the RPS mandate may be met by other than zero GHG resources or addressed through optional compliance measures. This includes the use of unbundled renewable energy credits (RECs) or Portfolio Content Category 3 resources; retirement of RECs associated with excess procurement in a prior compliance period; justified delay of timely compliance due to statutory recognized limitation; and cost limitations. Furthermore, since the cap-and-trade program and the state's RPS Program are not fully aligned, there are renewable resources that are used for compliance with the RPS mandate that are not counted as zero-emission resources under the cap-and-trade program.

*Unbundled Renewable Energy Credits*⁵⁷²: Retail sellers can meet up to 10% of their RPS compliance obligation with unbundled renewable energy credits. These unbundled RECs represent zero-GHG power that is not directly delivered to the utility's customers. The utility purchases the unbundled REC and surrenders it for RPS compliance. However, that portion of their retail sales would be met with non-RPS resources. Assuming absolute adherence to the 33% to 50% trajectory for non-emitting resources does not recognize the explicit statutory exception and penalizes the EDUs that exercise this statutory right.

*Banking of Excess Procurement*⁵⁷³: The state's RPS mandate also includes provisions that allow retail sellers and POUs to accumulate excess procurement from one compliance period and apply that renewable procurement towards meeting the RPS requirement for a future compliance period. Depending on the manner in which the underlying generation was utilized by the EDU when the excess procurement occurred, when the EDU uses excess procurement for RPS compliance but serves customers during that same compliance period with non-RPS resources, they would incur a cap-and-trade program compliance costs on the energy that is used to serve its customers equal to the amount of excess procurement applied to its RPS mandate. Since the proposal set forth in Attachment C does not recognize the ability of the EDU to meet its RPS compliance obligation with excess procurement, calculation of the EDU cost burden is understated.

⁵⁷² Public Utilities Code (PUC) sections 399.16, 399.30; see also Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities (<http://www.energy.ca.gov/2016publications/CEC-300-2016002/CEC-300-2016-002-CMF.pdf>), California Public Utilities Commission (CPUC) Rulemaking (R.) 11-05-005.

⁵⁷³ PUC sections 399.13, 399.30; see also Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities (<http://www.energy.ca.gov/2016publications/CEC-300-2016-002/CEC-300-2016-002CMF.pdf>), CPUC R.11-05-005.

*Delay of Timely Compliance and Cost Limitations*⁵⁷⁴: Renewable resources are often – although admittedly not always – located away from the load they are intended to serve. Recognizing the inherent complexities and potential delays associated with siting, permitting, and building renewable generation resources and the associated transmission infrastructure, the state’s RPS program also includes express provision that recognize timely compliance may be delayed. Likewise provisions that place limitations on the utilities’ expenditures for eligible renewable energy resources could excuse a utility from meeting the specified RPS mandate. In the event an EDU is faced with either of these circumstances, they may not be able to replace the affected resource with another renewable resource in a timely manner or be precluded from procuring renewable resources altogether. This would result in the use of additional generation resources with a cap-and-trade program compliance obligation that would not be recognized in the allowances allocated to the EDU to meet its program cost burden. (NCPA)

Comment:

A. RPS linear decline to 50% overstates the quantity of zero-GHG resources in EDU portfolios.

The allocation proposal reduces EDU allowances based on the assumption that EDUs will meet their RPS mandates which moves from 33% in 2020 to 50% by 2030.⁵⁷⁵ As justification for the proposed RPS trajectory, CARB cites to the increased RPS mandate adopted by SB 350 and the need to ensure that the cap-and-trade program compliance cost reflect the presumed decrease associated with greater quantities of renewable resources in the EDUs’ portfolios. However, what the rationale in Attachment C does not recognize is the fact that EDUs can be 100% compliant with their RPS mandate in 2030 without serving 50% of their load from instant renewable resource deliveries.

The RPS mandate codified in Public Utilities Code sections 300.11, *et seq.*, explicitly recognizes several instances when the amount of load served in a year by renewable resources may differ from the number of renewable energy credits (RECs) that the EDU surrenders to meet its RPS target for that same year.⁵⁷⁶ These provisions have the practical effect of ensuring that utilities acquire the necessary quantities of renewable generation to be compliant with the RPS mandate, but acknowledge that the renewable

⁵⁷⁴ PUC sections 399.15(b) and (c), 399.30(d)(2) and (3); see also Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities (<http://www.energy.ca.gov/2016publications/CEC-300-2016002/CEC-300-2016-002-CMF.pdf>), CPUC R.11-05-005.

⁵⁷⁵ Attachment C, p. 5.

⁵⁷⁶ Each of the statutory exceptions discussed herein are also reflected in the rules and regulations promulgated by the California Energy Commission and California Public Utilities Commission for the POUs and retail sellers, respectively. See Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities (<http://www.energy.ca.gov/2016publications/CEC-300-2016-002/CEC-300-2016-002-CMF.pdf>) and CPUC Rulemaking 11-05-005.

energy credits that represent those resources may not always be retired in the same time period in which the electricity is generated. Similarly, the provisions account for financial, market, regulatory, and other vagrancies that might impact the utilities' procurement of eligible renewable energy.

For example, the RPS program allows retail sellers and POUs to meet up to 10% of their RPS mandate with unbundled RECs.⁵⁷⁷ When a utility exercises its statutory right to do so, that 10% of their retail load would be served by resources that would incur a compliance obligation under the cap-and-trade program. By assuming a straight-line trajectory to 50% RPS without also recognizing this provision in the same statute, the CARB proposal underestimates the EDU cost burden. Similarly, the statute allows for banking of excess procurement.⁵⁷⁸ This means that POUs that procure more RPS-eligible electricity than they need to meet their RPS mandate for any given year can bank the RECs for use in a future compliance period. The utility would be compliant with the RPS program requirements because it surrenders the banked RECs, but depending on how the excess generation was utilized, the utility may be serving retail customers in that future compliance period with non-renewable resources for which a cap-and-trade program compliance obligation would accrue. Cap-and-trade program compliance instruments would need to be surrendered for those resources, but would not be included in the calculation of cost burden used to determine the number of allowances the EDU requires. The state's RPS program also recognizes instances where timely compliance with the RPS mandate is delayed without penalty to the EDU.⁵⁷⁹ Unforeseen delays associated with siting, permitting, and building renewable generation resources and the associated transmission infrastructure may delay the procurement or acquisition of renewable resources intended to meet current RPS mandates. EDU renewable procurement can also be affected by cost limitation provisions.⁵⁸⁰ In instances where the EDU's timely compliance is delayed for these reasons, EDUs may need to purchase electricity from non-renewable sources to serve their retail customers, causing the EDU to incur a cap-and-trade program compliance cost.

Furthermore, compliance costs are also affected by the EDU's ability to utilize the RPS adjustment. The manner in which the firmed-and-shaped renewable resources are accounted for when delivered to California also impacts the cost burden of EDUs. For example, as the current application of the RPS adjustment excludes some Portfolio Content Category 2 and 0 resources from the RPS adjustment, a cap-and-trade compliance obligation is assigned to those resources, despite the fact that those same resources are included in the calculation of RPS resources for which no cost burden is assigned under the CARB proposal.

⁵⁷⁷ Public Utilities Code (PUC) sections 399.16, 399.30.

⁵⁷⁸ PUC sections 399.13, 399.30(d)(1).

⁵⁷⁹ PUC sections 399.15(b), 399.30(d)(2).

⁵⁸⁰ PUC sections 399.15(c), 399.30(d)(3).

Under the current assumption of a 50% straight-line RPS increase to 2030, the cost burden associated with non-renewable resources directly linked to the RPS program would not be included in the calculation of allowances allocated to the EDUs, resulting in increased costs for electricity ratepayer. Equity requires the allocation proposal to recognize these important provisions in the state's RPS laws, and not just the total mandate. Taking into account the reduction in allocated allowances already imbedded in the cap decline factor and the need to fairly account for the fact that the 50% RPS mandate does not necessarily equate to 50% nonGHG emitting resources, M-S-R believes that it is more appropriate for CARB to base annual RPS requirements using a flat trajectory of 33% through to 2030. (M-S-R)

Comment:

ARB Proposed Treatment of RPS Percentage Targets in Determining Allowance Allocation

ARB proposes to apply the RPS percentage targets in SB 350 and assumes that RPS power will grow from 33 percent of retail sales to 50 percent in 2030 on a linear path.⁵⁸¹ In other words, ARB assumes that all renewable energy under the RPS would be treated as zero emission. This assumption is inappropriate given that it is inconsistent with the manner in which ARB treats some types of renewable energy under the Cap-and-Trade and Mandatory Reporting Regulations. In particular, the RPS program allows up to 10 percent of the RPS target to be met using unbundled RECs (unbundled RECs from a renewable source have the renewable attributes but the energy from the renewable source which is sold separately does not); however, ARB's regulations do not recognize unbundled RECs as zero emission energy. In addition, there are limitations regarding the extent an EDU can claim a zero GHG emission obligation under the RPS Adjustment provision for renewable energy procured under a contract but not directly delivered to California. These two regulatory limitations directly impact LADWP and the proposed application of the RPS percentage targets without adjustment would result in significant additional costs to LADWP to procure additional allowances for zero emission energy.

For these reasons, LADWP requests that ARB take this feature of the RPS program into account by reducing the assumed amount of electricity supplied renewable energy in each EDU portfolio for each year by 10 percent and increasing the level of electricity supplied by gas-fired generation by 10 percent. (LADWP)

Comment:

ARB's Proposed Methodology Combines the Cost Burden Methodology and Cap Adjustment Factor in a Way that Substantially Under-Allocates Allowances and Should Be Revised

⁵⁸¹ 2021-2030 Allowance Allocation to Electrical Distribution Utilities dated December 21, 2016, p.4

ARB is proposing to reduce allowance allocations by the application of a Cap Adjustment Factor. The application of the Cap Adjustment Factor is in addition to the reductions that LADWP would achieve through the shutdown of its remaining coal-fired generation at the IPP in Utah, substantial increases in renewable energy generation, and other measures it intends to undertake to reduce its GHG emissions system-wide as outlined previously. As a result of combining these utility-specific reduction efforts with the Cap Adjustment Factor, the proposed 2030 allocation to LADWP would be an over 70 percent reduction from LADWP's 2020 allowance allocation. Furthermore, this allocation level would have the effect of requiring an over 80 percent reduction from LADWP's 1990 CO₂ emission levels (assuming purchase of no additional allowances) - a reduction level that is twice as much as the SB 32 goal of achieving a 40 percent GHG emission reduction from 1990 levels by 2030.

The proposed allowance allocation would have the effect of imposing a disproportionately stringent GHG reduction obligation on LADWP (as compared to the statutory reduction target). This disparate obligation would be very costly to LADWP's ratepayers and would not address ARB's stated intent to protect ratepayers from the cost burdens of the Cap-and-Trade Regulation. Over 20 percent of LADWP's ratepayers are on its low-income and lifeline programs and would be substantially and adversely impacted by this additional cost. We urge ARB to consider the cost burden of implementing GHG reduction actions and mitigate it to the maximum extent possible through a full allocation of allowances. The importance of CARB correcting this flaw in the allocation methodology is underscored by the fact LADWP has been making unprecedented major capital investments that would result in significant GHG emissions reductions on a LADWP system-wide basis. These investments over the next 10 years include \$6.1 billion for expanding our use of renewable energy, \$1.4 billion for replacing our in-basin generation with new advanced high efficiency gas-fired generation, \$1.2 billion for implementing end-use energy efficiency measures, \$250 million for electric vehicle infrastructure and \$279 million in developing increased energy storage capacity.

In the same vein, it is imperative that each sector bear its fair share of the GHG reduction obligation. The draft 2030 Scoping Plan discussion draft indicates that about 35 percent of the State's GHG emissions currently come from the transportation sector. One critical reduction strategy must be widespread vehicle electrification, in combination with cleaner, low-carbon electricity generating resources. Transportation electrification is one of the most cost-effective GHG reduction strategies as shown in the table below.

LADWP GHG Reduction Strategy	Cost-Effectiveness (\$/metric ton)
Increase transportation electrification from base (290,000 EV equivalents by 2030) to high (580,000)	\$7-\$38*
Coal Replacement	\$20
Increase Energy Storage from 178 MW to 404 MW	\$334

Increase local solar from 1200 MW to 1800 MW	\$1230
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*GHG emission increases for LADWP but decreases for transportation sector, 1 to 4 ratio, respectively. The cost-effectiveness will depend on the extent EDUs will receive credit for net GHG emission reductions

As described in greater detail below, to support transportation electrification, LADWP is considering heavily investing in electric vehicle charging infrastructure and promoting electric vehicle technology.

The imposition of a Cap Adjustment Factor on EDUs such as LADWP to reduce allowance allocations in addition to reductions achieved through energy efficiency and fuel-switching to lower carbon fuels would result in EDUs being required to purchase significant amounts of allowances for compliance. Such an approach would effectively impose costs on the EDUs for net GHG emissions achieved through electrification and remove the incentive for EDUs to invest in electric vehicle infrastructure. Increased compliance burden imposed on the EDUs that lead to significant rate increases to customers removes the incentive for them to invest in electric vehicles. Instead, ARB should develop allowance allocation rules, as well as other regulatory mechanisms, that encourage vehicle electrification by EDUs for achieving net GHG reductions.

ARB's proposed allowance allocation methodology involves three steps:

1. Calculate the number of allowances that each electric utility would need to mitigate the cost impacts on ratepayers-effectively the utility's expected emissions based on projections of load growth, renewable energy requirements, implementation of energy efficiency measures, and planned unit retirements.
2. Further discounts this allowance level by the yearly cap adjustment factor; and then
3. Subtract the allowances that must be reallocated to industrial covered entities in order to offset the costs for the emissions associated with their electricity purchases.⁵⁸²

Applying both the first and second steps of this allocation methodology ARB does not achieve one of the most important goals that underlie each step individually. In particular, by applying the second step to the first, ARB is *by definition not* allocating sufficient allowances to cover the cost burden on ratepayers that will be imposed by compliance with the program.

Applying the cap adjustment factor to a level of emissions that reflects reduction commitments raises major methodological concerns. The cap adjustment factor generally reflects the rate of the decrease in the economy-wide emissions *from the level*

⁵⁸² Enclosure C. LADWP remains concerned regarding the reduction in EDU allocation based on allocation to industrial covered entities for emissions associated with their electricity purchases (step (3)).

of GHG emissions in 2020.⁵⁸³ However, ARB has not proposed to apply it to an individual

EDU's baseline 2020 emissions. Instead it first would discount the emissions associated with the utility's known commitments and then apply the cap adjustment factor to the discounted emission levels. This will result in an allocation that is less than what is needed to meet each electric utility's proportionate share of reductions based on the economy wide cap reduction and on a sector-wide basis, it will result in an allocation of allowances to the electric sector in an amount that is substantially less than the sector's proportionate share of reductions needed to meet the statewide GHG reduction target of 40 percent below the 1990 level by 2030.

Combining the first and second steps, in effect, penalizes EDUs that do more than their proportionate share to reduce emissions by giving those electric utilities only a discounted percentage of what they have committed to do. This approach has the counterproductive effect of discouraging such commitments in the future.

The following are possible approaches to addressing this issue with the current allocation methodology:

Alternative 1: Eliminate Cap Adjustment Factor

One possible alternative is for ARB to eliminate the use of the cap adjustment factor in the allowance allocation methodology. Under this approach, each utility would be allocated the number of allowances needed to meet its expected emissions after known commitments, which are very substantial due to the many complementary GHG reduction obligations (such as renewable energy and energy efficiency mandates) imposed on the electric power sector.

This approach has a number of advantages. It is the approach that is most fully in line with the policy basis by which ARB is making allocations to EDUs in the first place.

That is, by providing allowances for each ton of GHG emissions for which an EDU will have to surrender allowances (directly, or indirectly as reflected in the cost of purchased power), it is the approach that most directly and fully reflects the cost burden that the Regulation will impose on ratepayers.⁵⁸⁴ Forgoing the use of the cap adjustment factor is consistent with how ARB has approached allocations since the start of the program.⁵⁸⁵ And importantly, because of the fundamental structure of a cap-and-trade

⁵⁸³ The cap adjustment factor ARB proposes to apply to expected EDU emissions is the ratio of the 2020 Cap Adjustment Factor and the Cap Adjustment Factor for a given year post-2020. This ratio reflects, on an economy-wide basis, the percent decrease in emissions from 2020.

⁵⁸⁴ Enclosure C, P.2 ("ARB staff proposes to continue allocation to EDUs for the benefit of ratepayers, consistent with the goals of AB 32, beyond 2020")

⁵⁸⁵ ARB, Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector, p.5 (July 27, 2011). <https://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf> ("each utility can expect to be able to fully compensate their customers for the costs associated with the cap and trade program that are expected to be passed through to customers")

approach to GHG reduction, this approach is consistent with the overall emission reduction goals of SB 32 and reflected in the forthcoming 2030 Scoping Plan.

Alternative 2: Hybrid Approach

If ARB believes that its allocation methodology must reflect both reduction obligations, it could do so not by applying the cap adjustment factor to the level of emissions expected based on known commitments, but instead, for each year, independently calculating each approach, and selecting, for that year, the approach yielding the more stringent or lower allowance allocation. This would ensure that in any year, an EDU's allocation will reflect reductions at least in line with the EDU's fair share of reductions expected by the cap decline factor. And it would also ensure that if the EDU is expected to voluntarily reduce beyond its proportionate share of reductions, it will only receive allowances sufficient to cover the consumer cost burden of those emissions. However, unlike ARB's proposed approach, it will not allocate allowances less than both the EDU's fair share and the level needed to cover consumer costs.

Specifically, this approach could use the following formula:

Allocation_{year x} = The Lesser of A or B, where-

A = (EDU Specific Emissions₂₀₂₀ · Cap Adjustment Factor_{year x})

B = EDU Specific Emissions_{year x}

(LADWP)

Comment:

The ARB should not include a 50% linear RPS assumption in the allowance allocations. This assumption does not reflect the phase in of compliance periods for the 50% by 2030 RPS program. The phase in will also not reflect the panoply of costs that may be imbedded in the achievement of the RPS. For example, TID cannot develop and balance all of its RPS needs within its BAA and consequently incurs significant costs delivering RPS energy to its Balancing Authority Area (e.g., the payment of the Transmission Access Charge). Moreover, the RPS assumptions do not address the fact that LSE's can bank RPS procurement and may be able to procure less RPS energy than is needed within a particular RPS compliance period. The 50% RPS assumption will increase overall program costs associated with meeting the full scope of the State's climate objectives and does not adhere to the ARB's guiding principle for EDU allocations (i.e., to allocate based on expected cost burden). The ARB should instead apply a 33% RPS assumption to the post 2020 allowance allocations.

Due to operating its own Balancing Authority and needing to supply fully integrated energy produced by renewable generation sources, TID faces unique challenges. A small balancing authority is unsuitable for high concentrations of intermittent renewable generation. Balancing authorities outside of the CAISO merit individual consideration when contemplating the allocation process. TID's forward resource plan optimizes our

generation portfolio both financially and physically, mixing in our BA requirements; this drives our S-2 filings with the CEC. The Phase 1 Cap & Trade “cost burden” allocation approach (2013-2020) took these resource plans into consideration, and is a much more accurate way of determining what the true GHG cost burden is to the TID ratepayer. TID urges Staff to take a fresh look at the unilateral application of RPS procurement to load.

In conjunction with the RPS target allocation declination, the ARB should consider the fact that the electricity sector is already subject to emission reductions by virtue of other state policies, such as the RPS. The ARB should reconsider the Cap Adjustment Factor (CAF) for the electricity sector as it drives up costs for cap-and-trade compliance. With the economy wide “Cap” already set at a severe decline (from 334 mmtCO₂e in 2020 to 193 mmtCO₂e in 2030), the application of the CAF will increase compliance costs for TID even more, when TID, and the EDU’s in the current proposal are being asked to cut emissions by 67-70%. This undercuts a fundamental ratepayer protection rationale for free allocation to EDUs. (TURLOCKID)

Response: The commenters request increased allocation for EDUs, in particular by assuming that EDUs have only 33% renewable electricity throughout 2021-2030, by assuming that EDUs have less zero-emission electricity than the overall annual RPS standard, by removing the cap adjustment factor, and/or by phasing in the new calculated EDU allocations by instituting linearly from 2020 allocations to the new allocation calculations in 2025.

Several commenters emphasize the importance of the RPS Program in affecting appropriate allocations in particular. For details on how ARB staff proposed to address this, see the response to 45-day comments B-1.3

Several commenters note that EDU allocations will drop significantly between 2020 and 2021. Allocations for 2013-2020 were based on the most recent data and forecasts available at the time. When allowances are allocated in advance of a period based on projected load, resources, and resulting cost burden, there is a risk that the load projections will be too high or too low. The most recent CEC forms show that 2013-2020 EDU allocation likely results in an over-allocation of allowances to EDUs with respect to Cap-and-Trade Program cost burden. The use of more recent forecasts, based on more recent data, therefore results in lower allocations. Staff is proposing that, going forward, 2021-2030 allocations are based on the most current data and forecasts available. This issue is discussed further in Appendix C to the 1st 15-Day Notice.

Some commenters assert that the sudden change in allocation will result in sudden rate increases in 2021. Staff disagrees, as this is not possible for IOU customers, since they currently see a full GHG cost in their electricity rates. Decreasing allocation would only reduce their climate credits and should have no effect on rates. Other utilities set their own rates without CPUC oversight, and

thus can design similar or customized methods of using their allocations in a way which does not include rate shocks. For example, they could plan ahead for the decrease in allocations by banking auction proceeds, passing the GHG cost through to their customers, and returning auction proceeds to ratepayers in a non-volumetric manner. This would have the dual benefit of incentivizing reductions in electricity consumption while protecting ratepayers from net costs.

Under the second 15-day amendments, the difference between total EDU allowance allocation in 2020 and 2021 is 12 percent.

B-1.2. Comment:

The 15-Day Changes include CARB's proposed methodology for allocating allowances to the EDUs for 2021 to 2030. As a threshold matter, M-S-R appreciates CARB's continued recognition of the importance of providing the EDUs allowances to cover their program cost burden. EDUs provide the most direct link to electricity customers and are best able to return the allowance value to those ratepayers to further the objectives of AB 32. Because the allowance value directly protects ratepayers from the impacts of sudden rate increases associated with the program, it is important that the EDUs' allocation be sufficient to cover the cost burden associated with the post 2020 cap-and-trade program. (M-S-R)

Response: The commenter expresses support for allocation to cover EDUs' cost burden due to the Cap-and-Trade Program. Staff appreciates the support, while clarifying that although allocation to EDUs is based largely on the cost burden concept, it may not equal the cost burden for each utility. Allocation values may also differ from actual costs because costs cannot be predicted with precision.

Utility-Specific Details of Allocation Calculations

B-1.3. Comment:

Assumptions in the Allocation Calculations

To accurately calculate the cost burden of all EDUs, the assumptions upon which adjustments are based must be correctly applied. The allowance allocation Proposal includes an annual decline in the number of allowances allocated based on "the assumption that each EDU procures RPS eligible power that increases from the mandated 33 percent in 2020 to 50 percent in 2030." (Attachment C, p. 6) Attachment C makes clear that CARB believes that the allocation methodology must reflect the mandates of SB 350 and that those requirements will result in a "significant decrease in cost burden that is associated with increasing renewable electricity purchases." (Attachment C, p. 5) These assumptions about renewable procurement upon which this proposal is based are not applicable to the Cooperatives.

The Proposal does not recognize the disproportionate cost burden of the Cap-and-Trade Program on electric cooperatives. The Program impacts the members of electric

cooperatives disproportionately because the allocation methodology assumes each EDU is required to increase their Renewable Portfolio Standard from 33% to 50% from 2020 to 2030, and only attempts to mitigate the incremental impact of the Program. Electric cooperatives are regulated differently than other types of EDUs and, therefore, using the same regulatory assumptions is inappropriate. Thus, the RPS assumption ignores the higher cost for electric cooperatives to comply with the Program. If the allowance allocation is indeed based on “incremental cost of power to serve load due to the requirement to surrender compliance instruments in the Cap-and-Trade Program,”⁵⁸⁶ then the methodology needs to recognize the greater incremental cost for electric cooperatives.

The Cooperatives are unique distribution utilities in California that provide electric service to very small, rural communities and they are as distinctive and diverse as the communities they serve. Decreasing allowances will have a greater negative effect on the ratepayer/member of our disadvantaged, rural communities due to the limitations of our fixed-income members.

There are several fundamental reasons why Cooperatives are regulated differently. By law, the cooperatives are not-for-profit, and are defined with the distinct purpose of transmitting or distributing electricity exclusively to its members “at cost.” (Cal. Pub. Util. Code, section 2776.) The Cooperatives provide electric service to their members living in rural communities that were unserved by for-profit investor-owned utilities, which charge “retail” rates. Cooperatives serve an average of 3-5 consumers per mile of power line; roughly 1/10 of the population density as some investor-owned and municipal utility territories. Therefore, the cost to serve customers is intrinsically greater.

Furthermore, electric cooperatives have debt and contractual obligations to the Federal government (United States Department of Agriculture’s Rural Utility Service and Power Marketing Administrations), which complicates our ability to make resource portfolio changes and divestments. This unique relationship with the federal government is an additional reason why Cooperatives have been distinctly regulated.

We ask Staff to reconsider their regulatory assumptions that were used to calculate the incremental impact of this Program on our members. (GOLDENSTATEPOWER)

Response: The commenter requests that staff “reconsider their regulatory assumptions,” presumably regarding the amount of electricity assumed to come from zero-emission RPS electricity in light of the differences between co-ops and other EDUs (i.e., co-ops are not required to meet State RPS mandates). Staff declines this request because it believes that a uniform incentive to procure zero-emission resources is appropriate for all EDUs, regardless of the State’s requirements. It would neither be appropriate nor equitable for ARB to allocate more allowances to co-ops for procurement of more GHG-intensive electricity

⁵⁸⁶ <https://www.arb.ca.gov/cc/capandtrade/meetings/20161021/oct-21-workshop-slides.pdf>

resources. Staff notes that the same assumption was made of co-ops in the calculation of 2013-2020 EDU allocations.

B-1.4. Comment:

To accurately mitigate the cost-burden of the Cap-and-Trade Program on all EDU electricity customers, electric cooperatives must be recognized as a separate type of EDU with very different regulations and costs associated with serving our member-owners. While we recognize that a uniform approach for all EDUs allows for a simpler methodology than examining each EDU based on different criteria, as discussed herein, there are instances when that single methodology fails to accurately reflect the legal obligations upon which the methodology is based; as a result, the methodology fails to properly capture the stated intent for which allowances are allocated to EDUs. For these reasons, we ask that Staff reexamine the assumptions used in the allocation methodology and to take a deeper look into the impact the Program has on our member-owners based on the specific information and data referenced in these comments. In particular, we urge Staff to reconsider the misguided assumptions about the incremental impact of the Program on electric cooperative member-owners as well as the significant shock of the 2021 allowance “cliff”.

GSPC appreciates the opportunity to provide these comments and looks forward to working closely with Staff as we refine the average annual load and forecast data. (GOLDENSTATEPOWER)

Response: The commenter requests that staff examine the impacts of the Cap-and-Trade Program on electrical cooperatives, including allowance reductions between 2020 and 2021. ARB works directly with individual utilities and other stakeholders on a regular basis, including electrical cooperatives. The final allocations incorporate amendments to load assumptions for six utilities, including one cooperative, to account for their unique circumstances using methods which are equitable across all utilities. The causes of the allowance drop between 2020 and 2021 are discussed further in response to first 15-day comment B-1.1. Since the commenter did not make a more specific request, no further response is needed.

B-1.5. Comment:

SVP is unique in the regard that our service territory is composed of 54,309 metered accounts, but of these accounts the load represented by residential demand amounts to less than 7%, while large commercial and industrial demand amounts to 90%. Over the last several years SVP has been able to attract many data centers to locate within our service territory. Data centers are very high energy users and a single customer/site may have a peak demand greater than 10 megawatts (MW) at a load factor greater than 80%. Adding just a few customers of this size can greatly impact future demand forecasts of a medium sized publicly owned utility like SVP, and SVP has added many in the past three years in addition to a queue of customer interconnection requests that will

be added over the next several years. Statewide, or regional estimates of expected demand growth do not account for the very localized growth experienced and expected to continue in SVP service territory due to access to the City's fiber optic communication network, robust electrical distribution system, mild climate, and ability to connect new customers in a shorter time frame than they would experience in other electrical distribution utility (EDU) service territories.

The City submits these comments due to the discovery of a significant discrepancy between the projected cost burden reflected in CARB staff's allowance allocation proposal and the projections prepared by the City. This is due to the fact that the CARB's *2030 projected load for the City is less than the City's 2016 actual load* (described as energy to serve load). As more fully described herein, the unprecedented load growth the City has experienced between 2014 and 2016 has rendered the data used to support CARB's proposed allocation for SVP obsolete. As noted in Attachment C of the 15-Day Changes, the first step in calculating the EDU allowance allocation is to "select appropriate data source for each EDU's projected generation." (Attachment C, p. 7) Based on unanticipated circumstances more fully addressed herein, the CARB proposal does not use the "appropriate data source" for SVP. In order to fairly and accurately calculate the projected cost burden for SVP and determine the appropriate number of allowances to allocate to cover the utility's cost burden, the appropriate data source must reflect the significant change in SVP's load.

Discussion

The City supports staff's recommendation to continue to allocate allowances directly to EDUs for the benefit of their electricity customers. The City supports the allocation of allowances to the EDUs based on the calculation of cost burden.⁵⁸⁷ The use of publicly available data based on information reported by the EDUs is a sound starting point for calculating the projected EDU cost burden for 2021 to 2030. It is important for CARB's proposal to be based on publicly available information that stakeholders can assess, but there is no reason why that data may not come from different sources. This is relevant because it is equally important that the data accurately reflect the current status of the EDU's load; any projection that begins with incorrect data—regardless of how sound the underlying methodology—will be less likely to project the outcome than otherwise expected.

In the current proposal, the calculation begins with the EDU's energy to serve load (generation), described as "the total amount of power required for serving an EDU's retail sales, taking into account transmission and other losses." Staff utilizes, when available, data from the California Energy Commission (CEC) 2015 Form 1.5a and 1.1c, derived primarily from the utilities' 2015 S-2 Forms. (Attachment C, p. 9) Using the same data sources, "Average Annual Growth" factors are used to project generation for years

⁵⁸⁷ While SVP views the proposed definition of cost burden is as unduly restrictive, these comments do not address the underlying definition of cost burden, but rather the use of cost burden as the basis for allocating allowances to the EDUs.

not included in the data sources. (Id.) This information is set forth in a spreadsheet entitled, Attachment C Table, 2021-2030 EDU Allocation.

For SVP, the Energy to Serve Load and Retail Sales projections included in the spreadsheets do not accurately reflect current load demands or growth taking place right now. Using the common data set proposed in Attachment C, not only is the 2021 starting point for SVP's future load projection nearly identical to SVP's 2015 actual load, it is less than their 2016 actual load.⁵⁸⁸

Table 1: CARB Projections v. SVP Actual Load⁵⁸⁹

Year	Energy to Serve Load	Retail sales
2030 - CARB	3,524,302	3,221,038
2021- CARB	3,390,000	3,097,000
2016- SVP	3,556,724	3,425,801
2015- SVP	3,354,817	3,201,675

As the table above demonstrates, SVP's 2015 actual figures differ significantly from what is reflected in CARB's projections. This disparity is even greater when compared to the 2016 load information compiled to date.⁵⁹⁰ As CARB notes in Attachment C, "the electricity sector has changed significantly in recent years, including load and energy source changes that significantly diverge from 2009 predictions." (Attachment C, p. 4) For many utilities, these changes include slowed or declining load growth. For SVP, an electric utility located in the heart of the Silicon Valley, those changes reflect growing load. Indeed, SVP has experienced unprecedented load growth in the last few years, due almost exclusively to "data centers" locating in Santa Clara. SVP experienced 5% load growth from 2014 to 2015, and an additional 7% growth from 2015 to 2016. Using the currently available data and continuing even a modest growth rate out to 2030, SVP numbers greatly differ from the numbers used in the CARB model. (See Attachment B, SVP: Retail Sales Growth 2006-2021) For these reasons, the allowance allocation set forth in Table 9-4 of the 15-Day Changes significantly underestimates SVP's cost burden- even under CARB's own definition- and substantially under-allocates allowances to the City.

Reasons for Load Disparity

The 2015 S-2s were used as the basis for the 2021-2030 allocation proposal because the information contained in those forms reflected updated data. However, for SVP,

⁵⁸⁸ Audited and publicly available data regarding SVP's 2015 retail sales and power used for retail sales can be found on the City of Santa Clara website in the 2015 Utility Fact Sheet.

⁵⁸⁹ CARB projections are taken from Attachment C, spreadsheet titled 2021-2030-edu-allocation; SVP load information is based on the City's Final and Audited 2015 Utility Fact Sheet and Preliminary 2016 Utility Fact Sheet.

⁵⁹⁰ Data regarding SVP's 2016 retail sales and power used for retail sales has been completed and is attached hereto. As Exhibit A. Once audited, that information will be available on the City's website.

even the 2015 submittal does reflect the most accurate data. While the CEC's estimates for overall state load remain nearly flat over the course of the allocation period, decreasing at an annual rate of 0.21 percent,⁵⁹¹ not only is SVP's load not declining, it is growing significantly. A great deal of this growth can be attributed to the fact that the City has become a preferred location for "data centers" driven by a confluence of factors that are unique to Santa Clara and the utility's location and infrastructure. The need for data centers is rapidly growing due to such elements as expanded cloud computing, the need for more data storage, increased data analytics, and the "Internet of Things" (the growing number of "smart devices" and devices with imbedded internet connections). These factors, as well as the number of large industrial customers in the City have given rise to a burgeoning "Data Center Industry" within SVP's service territory. In addition to proximity to high-tech customers using data centers, the City is ideally suited to house data centers because of its infrastructure. SVP has invested in its dark fiber network (installing more fiber-optic cable than was necessary at the time of the investment so that additional capacity could be leased to third parties) and electrical infrastructure to adequately supply reliable electricity to large customers in high-demand areas. A location close to high-tech customers and the need for minimal latency in their services (the ability to recall data in a rapid manner close to the user base), also make Santa Clara a preferred location for data centers. These data centers require specific facility requirements, and the owners make substantial investments in the property and state-of-the-art facilities that house the electronic equipment.

Santa Clara purposefully invested in the infrastructure to meet the needs of its large industrial customer-base. This investment enabled the utility to accommodate the data center facilities. However, the rapid expansion of data centers and the lead-time to bring such facilities online has transformed significantly over the last year. The current data center development trend has large "blocks" of new load added within months of initiating the interconnection process. In contrast, just a few years ago this process would take 24-months or longer. An internal study from SVP found that for the 12 month average ending June 2015, data centers accounted for roughly 34% of retail sales. By the end of August 2016, that percentage had grown to 39% of retail sales. Based on SVP's assessment of currently available data, this same trend is projected to continue through to 2019.⁵⁹²

This unforeseen increase in SVP's 2015 and 2016 load, and additional projected increases through to 2019, render the data currently being used to calculate SVP's allowance allocation inappropriate.

⁵⁹¹ Cap-and-Trade Regulation Post-2020 Allocation to Electric Distribution Utilities Informal Staff Proposal, October 14, 2016; p. 4.

⁵⁹² Santa Clara's load includes estimated growth in other segments of the economy , as well. This growth is associated with developments throughout the City. The City 's website includes information on business opportunities in the area, including an interactive map of the proposed developments and development projects. Information about the location of specific data centers, however, is not included due to the higher level of security and confidentiality associated with those facilities.

The Appropriate Data

The appropriate data source for SVP's projected generation is not the information contained in the CEC's load estimates that were based on SVP's 2015 S-2 filing. Indeed, almost none of the current load growth associated with the data centers going online is reflected in the S-2 filing that was submitted in 2015. The 2015 S-2s were prepared using final load estimates based on information updated in 2014. Since the explosive increase in data centers that occurred since 2014 was not anticipated, the information contained in those filings does not accurately reflect that load. Furthermore, from a planning perspective, the information submitted in the S-2 filings by Santa Clara is not intended to be used as an actual "load forecast," further confounding the difference between the data upon which CARB is basing its allocation proposal and the actual load and load growth SVP serves and expects to serve over the next four years.

Rather, the City posits that a different data source should be used to base the projected generation for SVP and calculate the utility's cost burden. SVP has documented the cause of the unanticipated difference which can be substantiated with publicly available data. The increased load and load growth projections addressed herein, and which SVP requests CARB use to verify an adjustment to the current proposal, also have implications for the utility in other venues, from its purchases within the California ISO, to the updated load information that is provided to PG&E. For these reasons, an exception is warranted and should be added to Table 2 of Attachment C to address the City's load changes. The City recommends that the exception to the methodology would have CARB utilize the City's official, audited financial statements for 2015 and 2016, which include information on SVP's retail sales and generation/purchases for retail sales that validate and confirm the information described herein. Using this updated information, CARB should revise the 2021 baseline for SVP that is used in the 2021-2030-EDU-Allocation methodology. Using the updated data for the 2021 baseline ensures that the projections through to 2030 will include a higher level of certainty, since the initial calculation will more accurately reflect SVP's starting point, where now it does not. Furthermore, based on the load growth projections and substantiated data, SVP's annual growth from 2021 to 2030 should reflect 2% growth.

The City appreciates that this request requires staff time to review and confirm the substantiating data. The City also recognizes that it would be necessary to recalculate the proposed allocation tables and update the overall allowance budgets to reflect the corrected data. This is necessary, however, to ensure that the stated purpose and objective of the allocation to EDUs is accurately reflected in the number of allowances allocated to SVP. Without these revisions to the data sources for SVP, the City will not receive an allocation of allowances sufficient to meet its program cost burden, to the direct detriment of its electricity ratepayers.

Conclusion

For the reasons set forth herein, an exception to the methodology described in the text of the proposed regulation and Table 1 of Attachment C is warranted to ensure that the appropriate data source is used for SVP's projected generation; such an exception is equitable, consistent with the stated objectives of allowance allocation to EDUs, and would not adversely impact any other stakeholders. Since the information upon which the City's cost burden is calculated does not accurately reflect the City's current load, the proposed allocation leaves the City significantly short of the number of allowances that would be needed to cover that cost burden for the entire period 2021 to 2030. To correct this shortcoming, the City asks that the 2021 baseline be adjusted to reflect the City's current load and revised load projections, based on publicly available and verifiable data, as more fully described above. (SILICONVALLEYPOWER)

Response: Silicon Valley Power (SVP) requests that staff increase SVP's load forecasts for 2021-2030 to reflect recent increases in load. Staff agrees that a significant increase in load has already occurred beyond the load forecasts in the utility's 2015 S-2 form, and that therefore an adjustment is warranted. As part of the second 15-day amendments, staff increased SVP's forecast load for 2020 to equal its 2016 reported load. ARB did not adjust the load increase factor, because future load growth is less certain. These details are also described in the Post-2020 Electrical Distribution Utilities Allowance Allocation Spreadsheet added to the record as part of the Second Notice of Public Availability of Modified Text.

B-1.6. Comment:

The SFPUC has previously submitted comments on CARB's staff proposal regarding the allocation of cap-and-trade allowances and incorporates those comments by reference.⁵⁹³

[The commenter attached the November 2016 comment letter emailed to ARB referred to in the last sentence of the preceding paragraph of this comment and its footnote. The November 2016 letter makes substantially the same points as those made in the current letter which is excerpted here and elsewhere in this FSOR.]

CARB's Proposal fails to recognize and reward, as required by statute, EDUs such as the SFPUC that have already taken early action to significantly reduce their GHG emissions

In allocating allowances for the initial 2013-2020 compliance period, the SFPUC advocated in its comments on CARB's initial staff proposal that any allocation of allowances should reflect, and reward, EDUs that had already significantly and voluntarily reduced their GHG emissions. This is consistent with the California Global Warming Solutions Act, Assembly Bill (AB32):

⁵⁹³ These comments are attached to this filing as ATTACHMENT A.

“In adopting regulations pursuant to this section and Part 5 [cap-and-trade], to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall... *Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.*”⁵⁹⁴

The Legislature recognized that a uniform standard for all regulated entities would unfairly penalize entities that took early actions on their own initiative to combat climate change. Instead, CARB is proposing that there should be “no energy efficiency/early action credit because early action has already been recognized and energy efficiency/RPS requirements are now essentially the same for all EDUS”.⁵⁹⁵ CARB’s general policy appears to be that there should be no recognition of early action for any post-2020 compliance obligation. This approach is counter to AB32 and fails to acknowledge a critical fact; entities that took early action lowered their baseline emissions levels and that baseline does not change whether the compliance obligation is pre- or post-2020. Any additional actions taken to lower an already low emissions level will be costlier and more difficult to implement.

CARB’s proposal also fails to recognize EDUs that have already exceeded the “energy efficiency/RPS requirements” that other EDUs are only now being required to meet.

CARB’s approach is neither supported by statute nor the legislative history of Senate Bill(SB)32. SB32 neither eliminated nor imposed any sunset provisions on “early action” credits after 2020. Instead, as Senator Fran Pavley, the author of SB32 stated;

“By simply amending the existing AB32 framework without any major mechanical changes to the regulatory implementation process, SB 32 ensures that the policy tools currently being utilized to achieve the existing 2020 greenhouse gas target remain available for the achievement of targets beyond 2020.”⁵⁹⁶

The final legislative analysis accompanying SB32 is equally clear that;

“Specifically, this Bill [SB32]...Requires ARB to consider historic efforts to reduce GHG emissions and objectively seek and account for cost-effective actions to reduce GHG emissions across all sectors.”⁵⁹⁷

Clearly, it does not make sense for CARB to continue to reward post-2020 any early actions that entities took prior to 2012 that reduced their emissions to the 2020 targets set by CARB. It equally does not make sense, however, for CARB to now fail to reward early action taken by entities prior to 2012 to already meet or exceed CARB targets other entities won’t have to meet until 2030, 2040, or perhaps even 2050. CARB in

⁵⁹⁴ Health & Safety Code 38562(b)(3)

⁵⁹⁵ CARB staff Power Point Presentation (Post-2020 Allocation to Electric Distribution Utilities) at its October 21, 2016 Workshop

⁵⁹⁶ Senate Environmental Quality Committee Analysis of SB32, p. 8 (April 27, 2015) quoting Senator Fran Pavley, the author of SB32.

⁵⁹⁷ Senate Third Reading Analysis of SB 32 (Pavley) As Amended June 30, 2016.

effect is punishing early action and discouraging entities from taking voluntary actions to exceed compliance targets.

SFPUC provides 100% of its electric energy from GHG-free resources such as its Hetch Hetchy hydroelectric system and in-city solar facilities, and has used these resources to operate the largest fleet of GHG-free electric powered buses and streetcars in the nation. The SFPUC's GHG footprint is already at a level that California's other EDUs are unlikely to achieve by the end of the 2030 (or perhaps even the 2040 or 2050) compliance periods. The SFPUC should be rewarded for these early actions.

One option, previously proposed by the SFPUC, is that CARB should establish a minimum allocation to each EDU. This allocation could be based on a "best practice" benchmark that CARB uses for other industries. A potential "best practice" benchmark for electric generation, for example, could be the system-wide average GHG emissions that CARB expects California's EDUs to reach by 2030 as a result of the state's GHG-reduction efforts or approximately 0.17 ton/MWh.⁵⁹⁸ EDUs that already meet, or exceed this target, should be recognized for their early action in reducing GHG emissions in the allowance allocation process.

The Latest Proposal Significantly and Unfairly Underestimates the "Cost Burden" that even EDUs that are 100% Renewable Incur Under the Cap-and-Trade Program; A Floor of at Least 20% is More Appropriate

CARB's initial staff proposal set a floor of allocating to each EDU a minimum amount of allowances equal to 5% of their forecasted electric demand. The only justification for this in CARB's initial staff proposal is the "assumption that load served by natural gas is assumed to never drop below 5% to account for support for variable renewable resources."⁵⁹⁹ CARB has provided no documentation as to how this number was derived. This 5% floor now appears to be carried over to CARB's formal proposal, once again without any explanation for its derivation.

Although it is not clear from either CARB's staff or formal proposals, the 5% floor appears to correspond to the "duck curve" developed by the California ISO which identifies the need for flexible resources (currently primarily fossil-fueled) to accommodate the ramping up of renewable resources in the morning and ramping-down in the afternoon, as well as fluctuations in output over the course of the day.

As discussed extensively in the SFPUC's comments on CARB's initial staff proposal, if the amount of the allowance reflects the need for flexible resources, a more appropriate range of 20% to 25% should be adopted. This higher value represents the even greater variation between renewable energy during the daytime versus night-time hours. The current 5% allocation actually has the effect of penalizing utilities with high renewable

⁵⁹⁸ Assuming a 50% RPS requirement in 2030; 10% of California demand being met with hydro-electric resources; and no remaining use of coal for electric generation, statewide average GHG emissions from the electric sector would be around .17 metric tons/MWh.

⁵⁹⁹ CARB Power Point presentation at October 21, 2016 Workshop

usage by failing to recognize the GHG cost burden these utilities incur in order to balance their supply and demand in real time.

CARB is basing its allowance allocation to EDUs using supply/demand forecasts (S-2 forms) submitted to the California Energy Commission (CEC) by California's electric utilities. These forms are based on an annual summation of supply resources against annual demand.⁶⁰⁰ There is no requirement that a utility's reported resources match its demand in real-time.

As a result, even a utility that reports on its S-2 form that it is 100% renewable could still incur a significant cap-and-trade "cost-burden" to the extent its renewable generation does not match its load profile, particularly between daytime and night-time hours.

A useful analogy is California's net energy metering program for roof-top solar. While a solar customer can claim that he/she is "off-the-grid" and the utility reports that its net energy consumption is zero on an annual basis, in reality the customer is generating 100% of his/her energy during the day, providing the surplus solar generation to the grid, and then receiving energy back from the grid (with the associated GHG-cost burden) during the night.

The same situation occurs with a California utility that is 100% renewable, particularly given the prevalence of wind and solar resources that California's utilities have used to meet California's RPS standards. During the day-time the utility would be meeting its needs from its renewable resources, providing its excess zero-GHG energy to the grid, and using this to offset, on an annual basis, energy acquired from the grid during the night to balance its supply and demand in real-time.

The California ISO tracks the hourly generation of energy supply relative to demand in its daily Renewable Energy Watch. As shown in the attached Renewable Energy Watch for October 30, 2016⁶⁰¹, while almost 100% of the wind/solar generation occurs during the hours of 8 AM through 6 PM, over ½ (56%) of the system demand occurs between the evening hours of 7 PM till 8 AM when there is little or no wind/solar generation. Thus, a utility that reports it is 100% renewable based on its wind/solar generation during the day could still end up incurring a 50% cap-and-trade cost burden for the energy it purchases at night to match its supply and demand in real-time. Zero-GHG hydroelectric generation can also vary significantly over both the course of a day as well as seasonally.

[The commenter attached a copy of the October 28, 2016 Renewables Watch fact sheet published by CAISO.]

⁶⁰⁰ Forms and Instructions for Submitting Electricity Resource Plans (CEC Final Staff Report, CEC-200-2012-007-SF) Prepared in Support of the *2015 Integrated Energy Policy Report*

⁶⁰¹ This was picked to be contemporaneous with the comment period. During summer periods, when demand is higher, this ratio could be even lower as additional gas-fired generation is brought on line to meet demand.

Based on the above examples, a cost-burden of up to 50% of annual demand could be justified even for a utility that is reporting that it is 100% renewable on its CEC S-2 forms. Moderating this to some extent is the presence of some zero-GHG resources (such as geothermal and hydro) that are available at night, although not likely in sufficient quantities.⁶⁰² Electric storage is still a nascent technology under development, and also represents an additional “cost burden” that a 100% renewable utility would need to incur. Instead, the most likely outcome is that electric demand during the night-time hours will be met with fossil-fueled resources and imports, and embedded in the price of these resources that the utility is paying would be the associated “cost burden” of the necessary GHG compliance obligation.

To address these concerns, the SFPUC proposes that the “floor” or minimum allocation of allowances issued to each EDU be set at a minimum of 20%, which is itself likely to be conservative. Absent some recognition for the need for utilities with high renewable usage to balance their supply and demand in real-time over a 24-hour cycle, as currently written CARB’s proposal could actually disadvantage these utilities relative to other utilities that have fossil-fueled resources that can be flexibly dispatched to meet their demand.

Imposition of a Declining Cap on Allowances Imposes an Unreasonable Cost Burden on EDUs that are 100% GHG-free

According to CARB’s proposal, even utilities that are 100% renewable still incur a “cost burden” for the need to utilize some natural-gas fired generation to “account for support for variable renewable resources.”⁶⁰³ According to CARB, this need is “assumed to never drop below 5%.”⁶⁰⁴

CARB’s 5% assumption about natural-gas usage is therefore analogous to CARB’s definition of the “lowest achievable emission rate” used to set standards for stationary sources. In other words, no further reductions in GHG emissions are possible by the EDU. This is a significantly different situation from other EDUs that are not yet 100% renewable in that they can pursue additional GHG reductions through changes in their resource mix.

Based on the above, it is unclear why CARB is then proposing that this minimum allocation to EDUs would in turn be subject to a further annual yearly reduction for each year between 2021 and 2030. Essentially CARB is asking EDUs that are already operating at the lowest achievable [GHG] emission rate possible to be required to achieve a greater than 100% reduction in their emissions. Such entities should be

⁶⁰² PG&E’s Diablo Canyon generation is largely utilized by PG&E, and thus not available to other utilities, and presumably will be retired by 2024/2025 according to its application to the California Public Utilities Commission (A.16-06-003)

⁶⁰³ CARB Power Point presentation at October 21, 2016 Workshop

⁶⁰⁴ Ibid.

rewarded for their accomplishment, or at the very least left alone. Instead, CARB's proposal would require the impossible; a negative emissions profile.

As noted above, the SFPUC believes a minimum allocation should be in the range of 20% to 25%, not 5% as proposed by CARB. However, whatever the minimum allocation is determined to be, it should be fixed for the entire 2021 through 2030 compliance period and not be subject to further reductions.

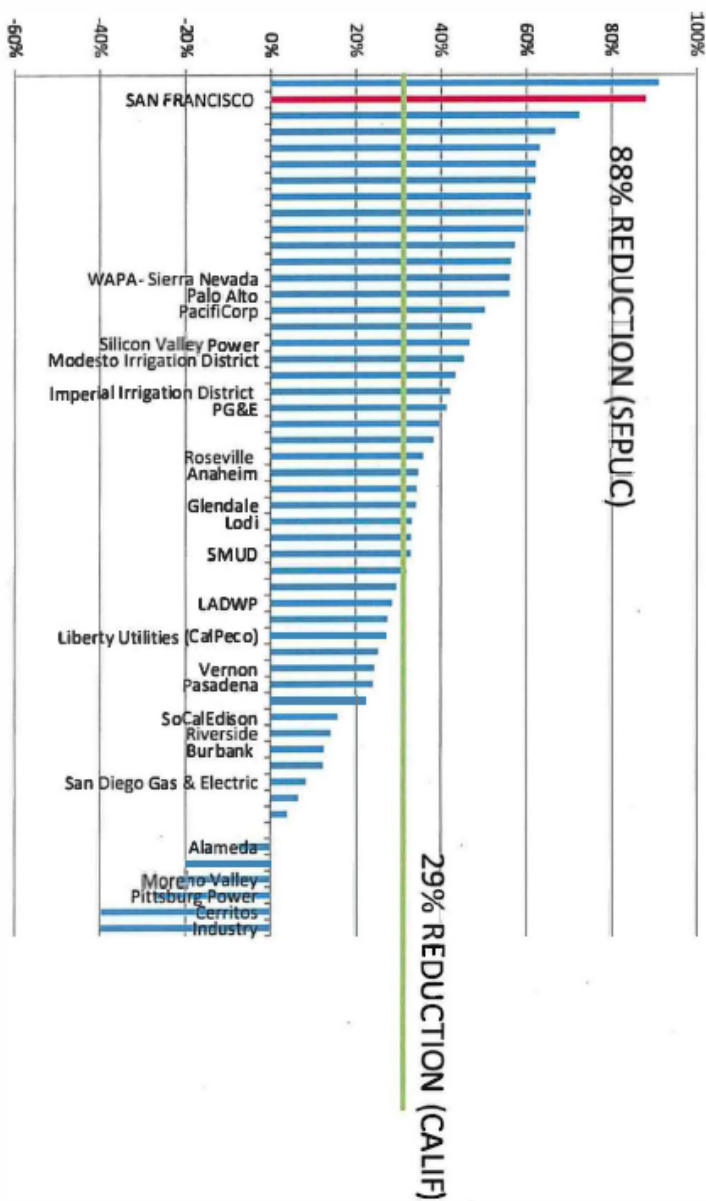
CARB's Proposal Would Drastically Reduce Post-2020 Funding for the SFPUC's On-going Programs to Reduce GHG Emissions.

In addition to being available to cover any GHG cost burdens incurred by the SFPUC, the SFPUC has used its allowance allocation to develop additional in-city GHG-free solar resources such as roof-top solar installations on schools and city buildings.

Funding for this program will be significantly reduced post-2020. As noted in the SFPUC's initial comments, the SFPUC's allowance allocation will drop 88% from 2020 to 2021. This is the second largest percentage drop⁶⁰⁵ out of all of California's electric utilities. This precipitous drop-off will significantly affect the continuation of SFPUC's efforts to promote new GHG-free resources. A phased-in reduction of allowances, or setting a minimum floor for allowances, would allow this program to better transition to new funding sources.

⁶⁰⁵ Surprise Valley Electric Cooperative is first with a 90% reduction.

REDUCTION IN GHG ALLOWANCES FROM 2020 TO 2021 (BY PERCENTAGE)



(SFPUC)

Response: The San Francisco Public Utilities Commission (SFPUC) requests increased allocation on the basis of its early use of low-emissions electricity, assuming utilities use a minimum of 20-25% natural gas power rather than 5%, or by allocating to EDUs on the basis of a “best practice” benchmark. Staff declines to make any of these changes.

SFPUC also requests that entities receiving an allocation based on an assumed natural gas minimum not have that allocation reduced annually. Staff addresses this, in effect, by ceasing (in the second 15-day regulatory changes) to apply the cap decline factor when calculating EDU allocations. SFPUC allocations for 2021-2030 do not decrease over time, but increase slightly over time due to increasing load.

ARB allocates allowances to EDUs in order to protect ratepayers from the costs associated with the Cap-and-Trade Program. Since SFPUC already has more than enough zero-emissions power to meet their load (according to their 2015 S-2 form), they would not be expected to face the same GHG costs as other utilities. ARB considers the five percent minimum appropriate in the interests of equity across utilities. That is, across all EDUs, staff assumed that each EDU requires a minimum of five percent (of the EDU's total load) natural gas power, representing the dispatchable power required to support variable renewables. This assumption ensures that every utility receives at least some allowances. Since SFPUC does not have commensurate emissions, the resulting allowance value received by SFPUC constitutes a reward for low GHG emissions. ARB does not see a need for further allocation.

ARB has already allocated for "early action" to reduce emissions. Also, EDU allocations are set in advance based on forecasts. If utilities reduce their emissions below forecasted levels, then they will benefit. This provides a reward for ongoing reductions.

SFPUC argues that the timing of zero-emissions power availability throughout the day typically does not align with timing of power demand. This applies to solar and wind power, as in the example, SFPUC gives using data from CAISO, which coined the term "duck curve" for this phenomenon. Other sources of power, often fossil-based, are sometimes used to "firm and shape" this power. ARB has reduced the amount of zero-emission power it assumes that EDUs use to fulfill RPS requirements by five percent to address this issue. However, as noted in their letter, SFPUC relies primarily on hydro power which is not bought through CAISO. Unlike solar and wind power which rely on the timing of the sun and wind, hydro power is often dispatchable when needed. Also, SFPUC has more hydro power than they need to serve their own load, as reflected in their S-2 form. Even the five percent natural gas power assumption represents an allocation of allowance value to SFPUC that is not needed to meet GHG costs, based on this analysis. Staff finds that no further allocation is needed to address any variability over time in SFPUC's access to zero-emissions electricity.

The commenter also suggests that ARB allocate to utilities using a benchmark. While a benchmark provides incentives to reduce GHG emissions, it also results in higher costs for the least GHG-efficient entities. ARB has instead opted to allocate to EDUs on the basis of cost burden because the purpose of EDU

allocation is to protect ratepayers, including ratepayers of the least efficient utilities.

The commenter also asserts that ARB somehow requires zero-emissions entities to reduce their emissions. ARB disagrees with this characterization. Nothing in ARB's previous proposals or adopted regulatory amendments requires a negative emissions profile.

B-1.7. Multiple Comments:

Technical Adjustments to the Recognition of DCPD Retirement

Third, PG&E encourages ARB to incorporate the following technical adjustment to its implementation of DCPD retirement in the spreadsheet. We note that DCPD's current operating licenses expire on Nov. 2, 2024 (Unit 1) and on Aug. 26, 2025 (Unit 2).⁶⁰⁶ We encourage ARB to prorate the assumed nuclear generation for PG&E in 2025 to reflect these license expiration dates. For example, a simple proration based on days of operation would result in assumed generation in 2025 of 33% (238/730) of normal generation, or approximately 6 TWh (i.e., Unit 1 not operating at all, and Unit 2 not operating for 127 days in 2025). This proration for 2025 is entirely consistent with ARB's overall methodology and we encourage ARB to include this adjustment in the next regulatory package.

Making the changes suggested in the sections above would yield an allocation to PG&E as represented in the table below.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2021-2030
<i>ARB Dec Draft</i>	22.6	15.6	14.4	13.6	12.9	11.5	16.4	15	13.7	12.5	11.3	137
Add: Adjust annual decline		0.4	1	1.3	1.9	2.4	2.6	3	3.4	3.7	3.9	23.6
Add: Transition assistance		2.9	2.6	2.3	2.1	2	1.9	1.8	1.7	1.5	1.3	20.3
Add: DCPD adjustment		-	-	-	0.1	4	-	-	-	-	-	4.1
PG&E Total		18.8	18	17.3	17	19.9	21	19.9	18.8	17.7	16.6	185

⁶⁰⁶ Pacific Gas and Electric Company. "In step with California's evolving energy policy, PG&E, labor, and environmental groups announce proposal to increase efficiency and renewables ,and storage while phasing out nuclear power over the next decade. " Press Release. June, 2016. https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160621_in_step_with_california_as_evolutionary_energy_policy_pge_labor_and_environmental_groups_announce_proposal_to_increase_energy_efficiency_renewables_and_storage_while_phasing_out_nuclear_power_over_the_next_decade

(PG&E)

Comment:

CARB's allowance allocation proposal is based on the use of the California Energy Commission (CEC) data that "provide the most recent, publicly available projections of load and EDU resources, and thereby provide the most robust basis for estimating future cost burden."⁶⁰⁷ NCPA appreciates the need to use on publicly available information from which load projections can be made, but notes that the CEC forms are not going to be the "appropriate data source for each EDU's projected generation."⁶⁰⁸ There are factors that can have significant impacts on the load projections; one such example is PG&E's proposal to close its Diablo Canyon Nuclear Generation Facility after it had submitted its load projections upon which the CARB allocation is based. To the extent that EDUs have clearly demonstrated and documented changes in the load forecasts that their allowance allocation was based on, NCPA encourages CARB to work with the stakeholder to determine an equitable means by which to address such circumstances. (NCPA)

Response: The commenters request that staff change its assumed retirement date for the Diablo Canyon Power Plant to reflect the dates when its operating licenses expire, and make similar changes. Staff implemented this change, although using a slightly different calculation than PG&E. The commenter suggests assuming the first unit at the plant operates during the entirety of 2024. Instead, staff averaged the months of license expiration to get a closure date of the end of March in 2025 and assumed that it was replaced with natural gas power at that time. This change is an example of how staff adjusted allocations to reflect updated load information during this rulemaking.

B-1.8. Comment:

6. Retail Sales Subject to RPS Mandate for the Port of Oakland

NCPA reviewed the basic methodology employed by CARB staff to calculate the allocation of allowances to each NCPA member. In doing so, we highlight one place where the approach needs to be adjusted. In the case of the Port of Oakland, the spreadsheet incorrectly assumes a retail sales estimate that is considerably higher than what is traditionally the case.

In general, the spreadsheet adjusts "Energy to Serve Load" to account for utility transmission line losses ranging from 7-15%. In the event that the projected difference between retail sales and energy to serve load exceeds 15%, the model simply assumes a 7% adjustment, ignoring instances where the differential may exceed the 15% level. For the Port of Oakland, the differential between load and retail sales regularly exceeds 40%, well above the 15% threshold. Such a relationship is evident in the various Power

⁶⁰⁷ Attachment C, p. 4.

⁶⁰⁸ See Attachment C, Table 1, p. 7.

Source Disclosure reports the Port of Oakland has filed with the California Energy Commission (CEC) over the past two decades, consistent with the definition of retail sales as defined by the CEC.

Since the CARB spreadsheet only provides a 7% adjustment to the Port of Oakland's retail sales number, projected retail sales are overstated as well as the amount of load subject to the RPS, which ultimately reduced the amount of natural gas in the Port's portfolio once California-eligible renewable generation is removed. In this case, the amount of natural gas remaining to serve load is understated, leaving Port of Oakland customers exposed to additional costs. NCPA does not believe this was CARB's intent, and recommends that the following adjustment be made to accommodate this unique circumstance.

The adjustment itself is relatively simple: the retail sales number that is currently included in Row 4 of the spreadsheet should apply to Row 5 of the spreadsheet, ignoring the 15% limitation assumed in the methodology. Doing so will increase the number of allowances the Port of Oakland receive between 2021 and 2030 from approximately 173,000 to 209,000. (NCPA)

Response: The commenter requests that allocation to the Port of Oakland use its reported retail sales as the basis of assumed zero-emitting RPS power, which is 40 percent below the Port's electricity load, rather than a default value of seven percent below load. For the reasons discussed below, staff declined to make this change, but did adjust the default value to 15 percent rather than seven percent.

For most utilities, the difference between load and sales reflects "line loss," which is electricity that was generated but dissipated from the electricity lines or was otherwise lost and therefore did not reach the end user. Line losses can vary by utility since they depend on factors including the distance between where the power is generated and where it is consumed.

The Port of Oakland is the only utility with forecast retail sales more than 15 percent below forecast load. This occurs because the difference between the Port's sales and load represents not only line loss, but electricity consumed by the Port itself rather than sold.

Staff believes that equity across utilities requires that a consistent zero-emissions RPS percentage be applied across all utilities. Staff is aware that the RPS program is applied somewhat differently to different utilities, including co-operatives, with regard to RPS power categories and the Port of Oakland with regard to what power is defined as a "retail sale" (the basis for RPS calculations). However, the role of RPS assumptions in EDU allocation calculations is to assume a consistent decrease in GHG emissions which is broadly reflective of the impact of the RPS program. Since ARB has removed the cap decline factor from EDU allocations, the role of the RPS assumption in representing GHG

reductions and distributing allocation reductions equitably across all utilities is of greater importance.

Some other utilities have line losses above seven percent. Given this, ARB concluded that it is appropriate to assume the maximum plausible value of line losses rather than an average. ARB has determined that the potential range is zero to 15 percent, and therefore decreased the Port of Oakland's assumed retail sales to 15 percent below load.

B-1.9. Comment:

Retirement of Intermountain Power Plant

LADWP supports ARB's incorporation of a 2027 retirement date for the Intermountain Power Plant (IPP), rather than the aspirational target date of 2025, into its cost-based allocation, given the considerable uncertainty regarding the actual retirement date of the IPP units. As LADWP stated in its previous comments, LADWP has set an ambitious goal to replace these two existing coal-fired generating units several years early. Its goal, however, is not a binding obligation to do so. LADWP's ability to meet this earlier date is contingent upon several factors, including the completion of a lengthy permitting process to build the new gas-fired replacement units, material procurement of the components and construction of those replacement units, and final concurrence of all 35 participants of the power sales contracts to terminate those contracts early. ARB's decision to use a 2027 retirement year correctly avoids LADWP from being penalized for the failure to achieve its aspirational goal for shutting down early these two coal units. (LADWP)

Response: Thank you for the support.

B-1.10. Comment:

PacifiCorp continues to support ARB's "cost burden" approach to post-2020 utility allowance allocations. Given its unique status as the only MJRP in California, PacifiCorp appreciates ARB staff's willingness to work with PacifiCorp to develop an allocation methodology that is based on public information and reflects PacifiCorp's MJRP status. One amendment PacifiCorp requests be made to its allocation calculation is to *not* include New Class 2 demand-side management as a zero-emitting system resource in the company's projected energy mix. This would be consistent with ARB's treatment of the other California utilities, where ARB is not including additional achievable energy efficiency in the allowance allocation calculations. (PACIFICORP)

Response: PacifiCorp expresses general support for the EDU allocation calculation methods and requests that staff consider its "New Class 2 demand-side management" as part of general load and not as having zero emissions. This category represents energy efficiency. Staff made the requested change as part of the second 15-day amendment package. Just as energy efficiency assumptions forecasted by most California utilities have been included as part of

load and not as having zero emissions, it is appropriate to apply the same policy to energy efficiency reported by PacifiCorp.

B-1.11. Comment:

Load Growth Considerations

CARB used an “average annual growth” factor in their load forecast methodology. The Cooperatives are concerned that low growth estimates will penalize EDUs for load growth.

Electric cooperatives are anticipating significant load growth that is not reflected in the “Energy to Serve Load” forecasts. Since this data is fundamental to projecting the cost burden of compliance with the Program, we believe the data must be revised to reflect dramatic differences in annual growth projections. Each of the cooperatives are experiencing or anticipating significant load growth due to agricultural irrigation load expansion, heating and cooling fuel switching, as well as transportation electrification.

Anza Electric Cooperative’s year-over-year load growth has been significant over the previous two years due mainly to marijuana cultivation, in addition to normal levels of new residential construction. In total, this growth is 3.4% per year, and expected to rise further with the legalization of marijuana cultivation in California. Average annual growth of only 0.41% was used to calculate allowance allocation, which significantly underestimates their cost burden to comply with the Program and detracts from the ability of AEC to mitigate the impact of the Program on their members...

We hope to work proactively with staff to identify acceptable source documents to substantiate the need to update the “average annual growth” factor used in Cooperatives’ load forecasts. Based on the demonstrated disparity between the cooperatives’ current load and documented load growth and the information used in the CARB allocation proposal (“Proposal”), the number of allowances allocated to the cooperatives is insufficient to meet their program cost burden.

(GOLDENSTATEPOWER)

Response: The commenter requests that EDU allowance allocation use updated average annual growth values for electric cooperatives’ load factors, and discusses the load growth of Anza Electric Cooperative in particular. As part of the second 15-day amendments, staff adjusted Anza’s assumed load upward from S-2 forecasted values to the 2016 actual value in response to discussions with the commenter and Anza regarding Anza’s load growth. Staff declined to adjust the load growth as well because future load growth is uncertain. Using a percentage load growth factor results in an exponential increase over time, so any increase to the load growth factor will dramatically increase predicted load. Although load growth may have been high during several recent years, that does not mean that it will continue at a similar rate during 2021-2030.

Staff is aware that disparities between predicted and actual load will occur, because predictions cannot be perfectly accurate. This is one of the costs of allocating in advance to provide certainty rather than calculating allocations each year based on more recent data. Such disparities are discussed further in response to first 15-day comments B-1.2.

Allocation for Transportation Electrification and Other Load Growth

B-1.12. Multiple Comments:

ARB should continue to remove disincentives for increased electrification in Transportation and other end-uses through the allowance allocation process. In order to meet the State's emission reduction goals in 2030 and 2050, electrification needs to be cost effective and remain a low cost alternative fuel for transportation and other end uses. SCE strongly supports the state's electrification goals and would like to highlight the need for ARB staff to continue its work with on a methodology for allocating allowances due to increased electrification. As the state continues towards its long-term climate targets, the emissions intensity of delivered electricity will continue to fall, making it an ever more attractive option as an end-use fuel. Electricity's role in powering transportation systems, industrial boilers, and building heating are just a few examples of the applications that may increase the emissions attributable to SCE (due to the nature of ARB's current accounting system) but would result in clear emission reductions from a societal perspective. In addition, electrification of the transportation and other sectors of California will yield substantial net reductions in criteria pollutants that will be needed for attaining ambient air quality standards for ozone and particulate matter under the federal Clean Air Act. SCE looks forward to discussing options to quantify these cross-sectoral effects and determine a reasonable method for delivering allowances to utilities where they are warranted. (SOCALEDISON)

Comment:

Transportation Electrification. We welcome staff's continued recognition of the need and commitment to assess potential modifications to EDU allocations to reflect increased emissions from the State's efforts to electrify the vast swaths of the California economy, starting with the transportation sector.⁶⁰⁹ Staff notes the importance of "ensur[ing] any method used to calculate any allocation for increased electrification is as accurate and verifiable as the methods used to allocate for industrial sectors for product-based allocation." While we agree that having "accurate and verifiable" data is important, this must be balanced with practical implementation constraints. It is critical to consider limitations on the availability of data and recognize the expected and real cost burdens that will be faced by electric utilities in collecting, managing, and submitting reports on such data. The timeframes in which various solutions could be implemented must also be considered. We encourage ARB staff to engage with stakeholders and other agency

⁶⁰⁹ [Attachment C: 2021-2030 Allowance Allocation to Electrical Distribution Utilities](#), released with the Cap-and-Trade regulatory package on December 21, 2016.

staff (in particular, those at the CEC) to identify possible solutions in an expedited manner. (SCPPA)

Comment:

Vehicle electrification will play a significant role in the future of the EDU sector and in achieving the state's emissions goals, and should be recognized in EDU allowance allocation. ARB continues to recognize that allowance allocation for electrification of vehicles and other sources of emissions remains an important issue and that the agency will work with EDUs to address it. However, the proposed allocation methodology is still devoid of any recognition of the issue. In Attachment C to the 15-Day Changes ARB states that, "it is important to ensure that any method used to calculate any allocation for increased electrification is as accurate and verifiable as the methods used to allocate for industrial sectors for product-based allocation." However, it is not feasible for EDUs to meter all load from electric vehicles. EDUs have no authority to require our customers to install or use separate metering equipment for their vehicles or electrified appliances. Vehicle electrification will play a large role in achieving the state's emissions reduction goals, and MID fears that additional cost burden for the emissions associated with increased load from electrification could increase electricity prices and result in a downward effect on demand of zero emission vehicles. An ideal solution would involve an after-the-fact allocation that closely estimates the additional load within each EDU's service territory, using information similar to that currently used by the Low Carbon Fuel Standard (LCFS) program. Many elements of the Cap-and-Trade program are estimated, and MID remains willing to work with ARB and other EDUs and stakeholders to develop a thoughtful method of estimating electrified load as well. (MODESTOID)

Comment:

There are a multitude of State Programs incentivizing the electrification of the Transportation sector, and the utilities will be incurring an increase in load and an increase in the associated emissions. The Scoping Plan assumes the state will add 4.2 million Zero Emissions Vehicles, or more. Furthermore, most realize that substantial additional building electrification will occur prior to 2030. Staff has indicated that they are open to providing "supplemental allocations" to the utilities in regards to electrification, as contemplated in SB 350. TID supports this effort and stands willing to assist in developing a methodology to account for increased vehicle and building electrification. (TURLOCKID)

B-1.13. Comment:

D. Appropriate Recognition of Transportation Electrification Remains Critical to Achieving the 2030 Target

The electric sector has a key role to play in helping achieve GHG emission reductions by electrifying the transportation sector. This will result in electric sector load growth

between seven thousand to twenty thousand megawatts by 2030 according to E3, and an associated increase in Cap-and-Trade compliance costs.⁶¹⁰ PG&E appreciates that ARB staff remains committed to assessing the potential for adjusting allocation to reflect GHG emissions that result from transportation electrification, as this will help ensure that regulatory incentives are aligned with California's desired environmental outcomes. We note that in addition to being accurate and verifiable, the methodology for determining GHG emissions from increased electrification must not be overly burdensome, or create regulatory obstacles that could slow the transition to electric vehicles. (PG&E)

Comment:

Allowance Allocations for Electrification

LADWP appreciates that ARB is open to a supplemental additional allowance allocation methodology in order to mitigate the consumer cost burden that may result from vehicle electrification.⁶¹¹ LADWP looks forward to working with ARB and CEC staffs to address methodologies to quantify the net emissions decrease that would result from electrification. Given that the transportation sector accounts for a significant portion of California's GHG emissions, electrification of the transportation sector could potentially have a significant impact in reducing overall GHG emissions and criteria pollutants. To support transportation electrification, LADWP is considering heavily investing in electric vehicle charging infrastructure and promoting electric vehicle technology. Providing an allowance allocation to cover the increased electricity demand resulting from electrification is critical for encouraging and maximizing LADWP's investment in electrification.

Furthermore, LADWP believes that similar efforts will be necessary as ARB moves forward with the electrification of industrial sources and other sectors of the economy. Given the importance of electrification in achieving both the climate change and air quality goals for California, it is important that ARB develop a regulatory framework that sends the correct market signals for encouraging the electrification of transportation and other sectors of the California economy. The following are suggested principles for ARB consideration in the development of such regulatory framework.

1. ARB should incentivize electrification in the transportation sector through its policies and programs, including, without limitation, the California Cap-and-Trade Program.

California's Low Carbon Fuels Standard (LCFS) is a complementary policy to the Cap-and-Trade Program that helps to reduce GHG emissions from the transportation sector. However, the LCFS is not sufficient to achieve the very substantial reductions in GHG emissions that are necessary to achieve California's long-term GHG reduction goals

⁶¹⁰ Energy and Environmental Economics. "California PATHWAYS: GHG Scenario Results." April, 2015. p 69.

https://ethree.com/documents/E3_PATHWAYS_GHG_Scenarios_Updated_April2015.pdf

⁶¹¹ Enclosure C, p.4

(i.e., 80 percent economy-wide GHG emission reduction by 2050). Other State policies are necessary for promoting the expeditious development and implementation of vehicle electrification and that some of these incentive policies should be incorporated into the Cap-and-Trade Program. Senate Bi11350 recognized this need when it directed ARB identify and adopt policies, rules, or regulations to remove regulatory disincentives to EDU investment in transportation electrification. SB 350 states, "Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers, and local publicly-owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification."

2. The compliance burden under the California Cap-and-Trade Program should not increase for EDUs as a result of the implementation of electrification measures that achieve net GHG emission reductions.

Vehicle electrification results in substantial net GHG reductions by shifting from the use of transportation fuels to cleaner, lower-carbon electricity. EDUs should not be required to obtain additional allowances to cover the increased GHG emissions incidentally resulting from the increased electricity demand due to vehicle electrification. Such an approach would effectively penalize EDUs for net GHG emissions achieved through electrification. Instead, ARB should develop allowance allocation rules, as well as other regulatory mechanism, that encourage vehicle electrification by rewarding EDUs for achieving net GHG reductions.

Similar mechanisms should also be developed for encouraging the electrification of other sectors of the economy.

3. Future projected electrification should be fully reflected in the baseline demand forecasts that ARB intends to use for allocating post-2020 allowances under the Cap-and-Trade Program.

ARB should proactively take measures to ensure EDUs receive full credit, and are not penalized, for increased load that can already be forecasted to result from vehicle electrification. This is best achieved by developing a methodology for fully projecting electricity demand increases for EDUs, based on current and future policies, measures, and incentives that will likely be developed to promote electric vehicle deployment through federal, state and local government initiatives. In addition, the methodology should give utility-specific emission reduction credit for additional policies, measures, and incentives that any particular EDU has committed or is planning to undertake to support and encourage deployment of electric vehicles.

4. ARB's allowance allocation rules should provide upfront certainty on the allocation of additional allowances if an EDU exceeds its projected electricity demand (as reflected in its baseline) due to unexpected increases in the levels of electrification.

ARB's allowance allocation rules should provide assurances that additional allowances will be available for distribution, as well as the specific number of allowances that will be allocated if EDU exceeds its projected electricity demand due to electrification. The development of such a mechanism is necessary to accommodate growth in electric vehicles beyond the level contemplated in the demand forecast that ARB will rely in setting the post-2020 allowance allocations. One approach for reallocating allowances to EDUs could involve the establishment of a reserve of additional allowances that ARB would use to cover the increased electric sector emissions resulting from future increases in vehicle electrification that would be necessary to meet overall GHG reductions goals of the Cap-and-Trade program. The allowances would be allocated to the extent that actual production levels exceed forecasted demand levels as a result of increased electrification.

5. Clear methodology and criteria must be established for determining when electrification exceeds forecasted measures used for setting an EDU's baseline electricity demand and allocating post-2020 allowances.

The Cap-and-Trade Regulation must include a methodology for determining when an electric utility exceeds projected electricity demand levels due to increased vehicle electrification beyond baseline projections. One reliable criterion could be the number of electric vehicle registrations in the State. When the number of electric vehicle registrations exceeds the level forecasted by ARB, this would trigger the allocation of additional allowances based on the increased electrification attributed to that utility. In addition, it would be appropriate for ARB to establish utility-specific application of criteria, given that there could be different levels of electrification and different GHG emission profiles for different regions of the State.

6. An emission accounting system must be developed to ensure sufficient allowances are allocated for vehicle electrification. This accounting system needs to provide estimates of the increased emissions to the utility sector with a reasonable degree of accuracy, timeliness, and reliability that is appropriate for achieving the goals of the Cap-and-Trade Program.

There must be an accurate accounting for the actual emissions attributable to vehicle electrification above pre-determined baseline projects. This methodology should incorporate data on increased generation and the net reduction of emissions due to electrification. The vast majority of electric vehicles (both battery and plug-in hybrids) have built-in charging data capture systems in place, which should help to provide a sound basis for such accurate accounting. (LADWP)

Comment:

Failure to include any provisions for allocating allowances to the EDUs to address the impacts of transportation electrification is a fundamental flaw in the allocation proposal. Given the state's clear direction to increase electrification of the transportation and other sectors, the impact on EDUs cannot be dismissed, nor "pushed down the road" for

future consideration. NCPA supports CARB's desire to ensure that the exact extent of those impacts can be uniformly quantified, and encourages ongoing work with the CPUC, CEC, and affected stakeholders on a long-term measure. However, as NCPA noted in the September 19 comments, while it is important to establish an appropriate metric for measuring the impacts of this transition, "that metric need not – and should not – be so cumbersome as to restrict practical acknowledgement of the impacts of transportation electrification." It is inappropriate to simply ignore these impacts on the EDUs pending development of such a methodology; it is not a question of "if" transportation electrification will impact the EDUs, but "how much" will they be impacted.

Furthermore, this is not a nascent issue; the impacts of transportation electrification on EDUs have been raised by stakeholders many times. As far back as 2010, stakeholders noted the demands that increased electric vehicle fleets would place on EDUs. CARB acknowledged the potential for impacts in the 2011 FSOR, but stated that "we do not expect that the growth in this electric load will significantly impact utility costs by 2020. We will monitor the electrification of transportation and will address this concern if it arises in the future."⁶¹² Since then, not only has electrification of the transportation sector continue to expand, but electrification of other segments of the economy have also increased. Added to this, the Legislature has placed an even greater focus on greater transportation electrification.⁶¹³ In light of the fact that transportation electrification is intended to play an increasingly significant role in moving the state towards its 2030 and 2050 emission reduction targets, NCPA believes that CARB should address this directive to remove barriers and recognize the impacts on EDUs now. Staff should continue to work with affected stakeholders, the CEC, and the CPUC on a feasible methodology that will accurately capture the emission ramifications of transportation electrification to the greatest extent possible. These further deliberations and assessment of options should be conducted as part of this current rulemaking and proposed amendments to address the effects of transportation electrification on the EDUs should be included in subsequent 15-day changes to the regulation. (NCPA)

Comment:

Load Growth Assumptions:

We support CARB's decision to use a "change in load" assumption, rather than a fixed load over the 2021-2030 period. However CARB's growth assumption overlooks a key consideration, in that electricity load will grow increasingly as electric vehicles are put to use on the road. While the growth pattern may vary between utilities, the increased

⁶¹² 2011 FSOR, p. 570.

⁶¹³ Health & Safety Code § 44258.5(b) The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification.

demand will be met with a mixture of electricity fuel types such as coal, natural gas, and wind or solar; subsequently, modeling of the anticipated and assured growth impacts will need to be performed to ensure that the cost burden effects are captured appropriately. These cost burdens include the expense associated with the upgrade of utility infrastructure, such as transmission and distribution burdens. (PASADENA)

Comment:

Electrification of the transportation sector is clearly a statewide goal that merits significant consideration when making forecast assumptions. However, we are concerned that Staff's focus on transportation sector is the only exception to load growth assumptions. Fuel switching to decarbonized electricity for home and building space conditioning is also a crucial part of the state's plan to reduce greenhouse gas emissions and should not be overlooked as having a potentially significant impact in the electricity sector's growth projections. Capping the allowances available to EDUs that experience growth from "beneficial electrification" would penalize those EDUs that proactively sought to encourage the state's overall greenhouse gas reduction goals to fuel switch away from fossil fuels in buildings and cars. (GOLDENSTATEPOWER)

Response: Please refer to the response to 45-day comments B-1.10, which answers these comments.

B-1.14. Comment:

SMUD also proposes that ARB establish a cap decline factor that is unique to the electricity sector, as a way to recognize the unique cost burdens placed on EDU customers in furthering State objective of sharply reducing carbon emissions (e.g., energy efficiency, distributed energy resources, etc.), and the increased emissions that will come in the electric sector as a result of increased electrification, particularly in the transportation sector. The increased emissions in the electricity sector that result from transportation electrification are more than offset by emission reductions in the transportation sector, today resulting in about 4 tons of GHG reduction for each ton of increase in the electricity sector.

Additional Allowances for Electrification.

SMUD appreciates the ARB staff considering some method within the Cap-and-Trade structure of accounting for the additional load and emissions from electrification. Broad substitution of electricity for fossil fuel combustion is an essential measure for achievement of Governor Brown's goal of a 50% reduction in petroleum use in vehicles by 2030. Electrification will reduce overall GHG emissions because it would result in a significantly greater decrease in emissions from the sectors or end-uses being electrified than the increase in emissions from additional electrical load. However, it represents a significant barrier to electrification when the increase in emissions in the electric sector is not covered in the Cap-and-Trade program.

ARB Staff has been insistent on requiring metering of the additional load from electrification of transportation, or some equivalently robust demonstration of this load, in order to reflect these emissions in the Cap-and-Trade structure. This is simply not feasible in the current electric transportation market, where most electric vehicles are charged at home without their electricity draw being separately metered. Requiring such a separate meter for demonstration of the additional load would be an additional cost burden that will reduce both EDU interest in and marketplace interest in investing in electric transportation.

The ARB should be comfortable relying on the demonstration and verification of increased electric load through the conservative estimation methodology that is used to generate Low Carbon Fuel Standard (LCFS) credits. It would be administratively efficient for the Cap-and-Trade program to take advantage of the same methodology as this complementary program, and not cost-effective of the Cap-and-Trade program to reject a methodology that is fully accepted by a sister program at ARB. The dramatic reductions of GHG emissions on the transportation side of the ledger (approximately 4 times the increases in emissions in the electric sector) implies a more than adequate “margin of error” to support providing allowances based on a simple, cost-effective structure that does not require metering or the equivalent.

Electrification of other end-uses, such as water heating, space heating, etc., is considered necessary by many academic studies to achieve the State’s longterm GHG goals. Once again, while likely less significant in magnitude than transportation electrification, it is not cost-effective to separately meter this load increase for purposes of demonstration of the load to receive allowances. EDUs could provide an estimation here similar to that for electric vehicles, based on a demonstration of the penetration of electric technologies for each end use, and the standard end use intensities (EUI) that are used in forecasting models and energy efficiency programs for various technologies (such as a heat-pump water heater that has a specific rated efficiency). While individual installations can use different amounts of electricity depending on consumer behavior, etc., these standard values are sufficient to provide good estimates of the electricity load involved. Verification would then simply be verification of installation or penetration of the technologies – how many were installed – rather than a complicated statistical analysis of before and after electricity use or some system of individual meters for each appliance.

Other methods of reflecting the overall effects of electrification without undue complication should also be on the table, outside of providing additional allowances on top of the basic EDU allocation structure. For example, the revised Cap Factor suggested above could be used through 2030 as an approximation of the impacts of electrification over time. Including a reflection of the impacts of transportation electrification in the underlying allowance structure makes sense, as that structure is already based on a variety of assumptions about loads and resources over time, not after-the-fact metered data. It seems unreasonable and counterproductive for the

allowance structure for EDUs to reduce allocations based on the assumed impact of RPS procurement, but then require after-the-fact proof of increased emissions for inclusion of electrification-related emissions. (SMUD)

Comment:

D. Transportation electrification must be recognized and addressed in this rulemaking

The allocation proposal provides no recognition of the impacts that transportation electrification will have on the EDUs and their electricity customers. Staff has committed to continuing to “assess the potential for adjusting allocation amounts to reflect emissions that result from electrification of transportation,”⁶¹⁴ as it committed to doing in the original Staff Report at the beginning of this rulemaking. However, this is not a matter that can continue to be deferred to future rulemakings. Indeed, if it is not addressed at this time, it will be at least a year to 18 months before any future amendments would be likely to be approved, further exacerbating the concerns that are being raised at this time; concerns that were raised and acknowledged as far back as 2010-2011.⁶¹⁵

The state continues to rely on increased electrification to meet its climate objectives. As such the legislature placed an emphasis on transportation electrification and the role it will play in helping the state meet its goals, and explicitly directed CARB to consider allocating allowances to electrical distribution utilities to address the increased emissions that would result.⁶¹⁶ M-S-R understands that CARB is seeking a methodology to both quantify the impacts and allocate allowances commensurately. To that end, CARB has been coordinating with the energy agencies and stakeholders; that process should continue with the objective of finding a long-term methodology that will recognize how electrification of all other sectors impacts the electricity sector, and in particular, the EDUs. However, rather than defer this issue until that process has been resolved, since transportation electrification will impact the entire electricity sector, the agencies must address the immediate and near term impacts *at this time*. Ensuring that such a methodology is accurate and verifiable should not be a deterrent to also ensuring that this issue is properly and timely addressed. (M-S-R)

Response: The commenter requests a decreased cap decline factor for EDU allocation or other accommodations for increased electrification of transportation and other activities. In the second 15-day regulatory changes, staff removed the use of the cap decline factor entirely from EDU allocation. Increased electrification is addressed further in the response to 45-day comments B-1.10. Staff considers a priori assumptions appropriate for Renewable Portfolio Standard (RPS) power, but not for transportation electrification because the

⁶¹⁴ Attachment C, p. 4.

⁶¹⁵ 2011 FSOR, p. 570.

⁶¹⁶ Health & Safety Code section 44258.5(b).

amount of RPS power is set by regulatory mandate while transportation electrification amounts and impacts continue to be highly uncertain.

B-1.15. Comment:

Proposed Calculation of Renewable Portfolio Standard Load

LADWP supports ARB's proposed approach which assumes that an EDU would meet its Renewable Portfolio Standard (RPS) targets based on retail sales instead of Net Energy for Load. This approach would be consistent with the approach set forth in the Public Utilities Code Section 399.11. (LADWP)

Response: Thank you for the support.

Allocation and the RPS Adjustment

B-1.16. Comment:

2. The RPS Adjustment Should be Retained

The 15-Day Changes would retain the RPS adjustment, rather than eliminate the provision as originally proposed. M-S-R appreciates staff's responsiveness to stakeholder concerns regarding the adverse implications associated with removing the RPS adjustment, and the proposal to retain the provision. The alternate proposal that had originally been proffered to replace the RPS adjustment would have failed to account for the actual RPS-eligible deliveries that an EDU has invested in. This would have cost M-S-R's member agencies millions of dollars in additional compliance costs each year and depreciated the value of the RPS-eligible resources for which their ratepayers paid a premium. As addressed in the M-S-R September 19 Comments, and in subsequent comments submitted by the Joint Utilities, the RPS adjustment is an important element of the cap-and-trade program that directly acknowledges the interaction between two of the state's pivotal climate programs.

However, merely retaining the RPS adjustment, without properly administering the adjustment or requiring the reporting and verification of the associated renewable energy credits, is not enough to ensure the necessary alignment between the RPS program and the cap-and-trade program. M-S-R urges the Board to recognize the significance of this alignment and the importance of the appropriate administration of the RPS adjustment, and direct staff to include proposed modifications to the regulatory language in subsequent 15-day modifications to the cap-and-trade program regulation and the Mandatory Reporting Regulation to ensure consistency and clarity. M-S-R joins in the January 20, 2017, Utility Recommendations to Improve Implementation of the Renewable Portfolio Standard Adjustment Under the Cap-and-Trade Program, and urges CARB to work with stakeholders to incorporate the program refinements addressed therein. (M-S-R)

Response: See responses to 45-day comments D-3.1 and D-3.2.

Inclusion of Industrial Covered Entity Electricity in Industrial Benchmarks and Removal from EDU Allocation

B-1.17. Comment:

We understand that the Western States Petroleum Association has provided comments on this 15-day package as well. Tesoro supports those comments, but wishes to provide additional focus on a couple of the subjects because our operations are somewhat unique in regards to these two aspects of the regulation. First, our refinery in southern California falls into both an Investor Owned Utility (IOU) service territory and in a Publically Owned Utility (POU) service territory, but also generates power.

2021-2030 Allowance Allocation to Electrical Distribution Utilities

In attachment C released with the 15-day changes, CARB continues to propose that allocation for electricity consumed by covered entities will be changed to a direct allocation method following the end of the 3rd compliance period.

Tesoro supports ARB's proposal to include emissions associated with electricity use by covered industrial entities in calculated industry-specific benchmarks and thereby provide allocation for electricity consumed directly to these industrial entities. Tesoro believes the proposal provides the opportunity for more equitable allocation, significantly reduces ARB's and the California Public Utilities Commission's (CPUC's) administrative burden, and improves transparency of the allocation process.

Within the refining sector, some facilities self-generate all or a portion of their power, some purchase all or a portion of their power from IOUs, POUs, third parties, or from more than one source. Currently, benchmarks are based on adjusted emissions per unit of production. Adjusted emissions include direct emissions plus emissions associated with steam purchases, minus emissions associated with steam and power sales. Emissions associated with power purchases have not been included in the adjusted emissions used to calculate ARB's industry specific benchmarks. Instead, allocations have been provided to the Electrical Distribution Utilities with the intent that the EDU's distribute the benefits of these allocations to energy intensive trade exposed entities (EITE's) or their rate payers. Though the CPUC has established a revenue sharing rule that closely parallels and compliments ARB's allocation methodologies, the CPUC rule does not apply to facilities or portions of facilities outside CPUC's jurisdiction. Though the POU' s have been directed to utilize EDU allocation for the benefit of rate payers, the benefits do not extend to self-generators or purchasers of electricity from third parties. Thus, for facilities outside of CPUC jurisdiction inequitable or perverse situations are likely to occur, particularly for facilities that self-generate and/or purchase power from third parties. ARB's proposal to include emissions associated with power purchases in the adjusted emissions used to calculate benchmarks affords ARB the opportunity to improve allocation equity within each industrial sector regardless of differences between facilities and their respective with power supply.

Additionally, direct allocation to industrial entities (for emissions associated with purchased power), will reduce the significant administrative burden associated with implementation of the CPUC rule; as well as, any necessity to evaluate the methodologies implemented by POU's to insure that such methods are consistent with ARB's objectives. In the case of the CPUC, the current approach requires exchange of data between ARB and CPUC, calculation of a dollar conversion factor to convert tonnes of allocation to rate credits, communication from CPUC to each IOU, and distribution of credits from the IOU's to their industrial customers; as well as checking the results to insure that the credits actually received by industrial entities are consistent with facility data and the CPUC rule. This process is both cumbersome and opaque. Inclusion of emissions associated with purchased power in ARB's direct allocation will reduce the number of steps in the process and improve transparency. (TESORO)

Response: The commenters express support for removing allocation for industrial covered entities' use of electricity from electrical distribution utility allocations (EDU) and adding it to industrial entity allocations. The regulatory amendments remove this allocation from EDUs for 2021-2030 using EDU-specific emission factors. Thank you for the support.

B-1.18. Multiple Comments:

Industrial Allocation Shift. SPPA and its Members oppose ARB's proposal to shift industrial electric allocation value away from POUs and to a direct allocation methodology. This policy proposal is another example of ARB staff's attempts to push POUs into an IOU regulatory/policy model. Similar to the suggested future requirement that POUs consign their allowances, this proposal is problematic from both a policy and implementation perspective. SPPA has repeatedly stated this position since the idea was first presented by staff. We have consistently maintained that position in all subsequent comments. The staff proposal, critiqued below, has been presented without a complete analysis or justification.

"This change will encourage pass through of program costs to industrial entities, thus incentivizing them to reduce emissions, while direct allocation will provide emissions leakage prevention in line with existing industrial allocation policy. This change will also remove the potential inequity between IOU-customer industrial covered entities, which already see a GHG cost and receive distribution of IOU auction proceeds to prevent against emissions leakage, and POU-customer industrial covered entities that may not be protected from emissions leakage."⁶¹⁷

The inequity cited by staff is not valid for the vast majority of POUs. The generic language neglects to discuss the impacts on EDUs that serve significant industrial loads. SPPA believes that in fact, the change will pass additional costs through to all industrial entities; and it will also result in costs being passed on to other POU customers. This shift will have a disproportionately high impact on EDUs who have

⁶¹⁷ *Ibid.*

significant amounts of industrial customers in their service areas, and will complicate local ratemaking (which should not be underestimated). For POU with sizable industrial load, the dramatic and additive reduction in POU allowance allocations will result in a distinctly contradictory effect as compared to ARB's intended use of allowance allocations.

Placing emissions leakage prevention in line with existing industrial allocation policy at a time when material reductions are occurring in industrial allocations is counter-intuitive to the goals being presented. This policy proposal has not been supported by staff analysis, and will create losses for both the utility and its industrial customers, regardless of size. EDUs will lose allocation flexibility and revenue which has historically been used to protect the very industries that this policy is stated to help. As a result, the industrial entities in POU service territories will not only see a significant price increase in their particular rates, but will also see dramatically decreased allocations from which to draw a counter benefit. The critical points about this proposed structure are summarized as:

1. The allowances provided to industry to cover purchased electricity carbon costs will be significantly less than the allocation that is currently provided to EDUs to cover the carbon obligations for that electricity;
2. The staff proposal exchanges one potential inequity (IOU versus POU customers) for two known inequalities:
 - a. Regional GHG emissions profile — The benchmarking allocation methodology will create geographic winners and losers, something that has been sought to be avoided in previous benchmarking efforts. Namely, industrial customers served by EDUs with higher-emitting portfolios (typically located in Southern California where water resources are scarce and coal plant retirements are forthcoming) may see a more pronounced impact from this policy;
 - b. Differing electrical rate impacts depending on an industrial facility's size — Compliance entities will feel a different price of carbon than those not large enough to be in the program.

Any staff policy concerns that exist regarding unequal treatment of industrial entities in IOU versus POU service areas should be discussed in detail, including estimated differential cost impacts, with all relevant parties. ARB should not take action until such discussion has occurred, and a number of solutions have been publically evaluated. When coupled with the consignment proposal, the industrial allocation shift creates a potential double hit to POUs that has not been evaluated by ARB staff. Neither POUs nor industrial entities have sufficient information to fully analyze the extent of the compounded impacts that could realize as a result of this policy change. (SCPPA)

Comment:

The POU Should Continue to Receive All Allowances for its Customers

The SFPUC supports continuation of the current process that allocates all allowances directly to the electric utility. For the investor-owned utilities, the California Public Utilities Commission (CPUC) is in the process of developing the appropriate mechanisms to allocate the value of allowances to affected Energy Intensive/Trade Exposed Industries (EITE). POU's can allocate the allowance value back to EITE industries through using their allowances either to reduce their own compliance costs and/or through their rate design policies.

However, if CARB chooses this approach the SFPUC proposes where a single government entity (such as a city) operates both the POU and the EITE industry, allowances would continue to be allocated to the POU. This would allow the government entity to exercise its own discretion to maximize the value and use of the allowances. (SFPUC)

Comment:

Deducting emissions associated with electricity sales to covered industrial entities from EDUs' allowance allocation should not be pursued. The 15-Day Changes continue to seek to reduce direct allocation to EDUs by an amount commensurate with the estimated emissions attributed to electricity purchased by Cap-and-Trade covered industrial entities, and instead supply a lesser amount of allowances directly to the covered industrial entities while the full compliance obligation for the industrial entities' electricity use remains with the EDU. Implementation of this proposal would be harmful both to the affected EDUs and to the covered industrial customers within those EDUs' service territories.

The value of MID's allocated allowances reduces the impact on its ratepayers from Cap-and-Trade compliance costs and above-market renewable energy procurement for compliance with the RPS program. Through cost control efforts and the allocated allowance value, MID has not raised its energy rates since 2011. Stable and predictive rates have been enjoyed by all of MID's customer classes and especially welcomed by the larger Industrial customers. More recent rate comparisons show that MID Industrial customers are situated at least as well as their peers within Investor Owned Utility (IOU) service territories for protection from emissions leakage.

Rate setting is a difficult and lengthy process, and the targeted nature of these rate changes could result in rate disparity among facilities producing similar products in a very close proximity, potentially inducing local economic and emissions leakage. Additionally, the changes mentioned above would require substantial changes to the POU's electric retail rates requiring alterations that conflict with the cost-of-service methodology the utility employs. These changes would not only need to be reconciled with the cost of service methodology but would make the POU vulnerable to various commercial and regulatory risks.

Electricity sales to the three covered industrial customer facilities within MID's service territory represent approximately 10% of MID's total annual retail energy sales. In 2015,

the allowance value allocated to MID in association with the covered industrial customers' electricity use was valued at \$1.5 million. If this value is no longer allocated to MID in the future, it will be necessary for MID to create special rates for these three customers to collect funds to cover the compliance obligation for their electricity use and avoid having MID's other ratepayers shoulder the cost of the covered industrial customers' emissions. Additionally, since a portion of MID's allowance value is applied for purposes that provide system-wide emissions benefits, MID will need to reflect in the covered industrial entities' rates that they have not contributed towards the cost of those emissions-reducing expenditures and ensure that they do not receive a double-benefit from the combination of other ratepayers' allocated allowances and allowances directly allocated to the industrial entities by ARB.

Ratemaking would be further complicated because covered industrial facilities would only receive allocation for electricity usage related to the processes within their operations that produce on-site emissions, even if the entire facility produces only the covered product. Not only will these customers need to be treated differently from other industrial customers, but these customers' load would need to be treated differently within each customer's bill. For example, a facility may only report 50% of its electricity usage as supporting the processes that are listed in Table 9-1 of the Cap-and-Trade Regulation (i.e. excluding office load, product conveyance, facility cooling, etc.), which would mean that the Publicly Owned Utility (POU) receives allocated allowances for a portion of the covered industrial customer's load and the customer receives allocated allowances for another portion of their load. It is infeasible for the POU to separately meter the energy used for only these processes and would need to create separate rate classes and rate calculations to account for this change.

Additionally, this proposed change would be harmful to the covered industrial entities. For every one allowance taken from their EDU, the covered industrial entity would receive less than one allowance. This disparity will necessarily be much less than the allowances taken from the EDU. The level of disparity would be contingent upon: a) the emissions profile of the EDU in whose territory the industrial customer is situated, b) each customer's energy efficiency relative to the other entities within their industry, and c) the assistance factor for their industry.

In the meantime, the EDU still receives the full cost burden of the covered industrial customers' emissions, and will need to pass those costs through to each covered industrial customer.

Therefore, under this change the costs of the covered industrial customer's emissions will remain relatively stable, but the amount of allowance value available to them to cover those costs will be drastically reduced. MID recommends that the resulting cost disparity be more widely communicated to affected entities through a series of workshops dedicated to the issue to ensure that all affected entities have the same understanding of the impacts. Any potential implementation of this change should be

delayed until the affected parties have enough information to fully assess its implications.

This change remains unwarranted and MID recommends that ARB not proceed with it so that EDUs may still receive allocation to reduce the cost burden for all load for which they generate electricity, including load from covered industrial entities. (MODESTOID)

Comment:

TID does not support the redistribution of allowances to the covered Industrial customers in our service territory. Our EITE customers have benefited from the allowance allocation as constructed from 2013-2020 in that TID has been able to shield not only the Industrial customers, but all of our ratepayers from the cost of Cap & Trade compliance. The increased costs associated with the lower allocation of allowances will be borne by all ratepayers while the fractional benefit due to the application of the assistance factor only marginally benefits the industrial customer. The reduction in allocations will result in costs that will be borne by all of our customers and will not be directly attributed to our EITE customers. To avoid placing this additional cost burden on all of TID's customers (particularly our disadvantaged communities), the ARB should not redistribute EITE allowances, or at a minimum, apply the assistance factors in the EITE redistribution. (TURLOCKID)

Comment:

CMUA opposes ARB's proposal to shift allocation value away from POUs and instead provide a direct allocation to industrial entities. Several of CMUA's members have raised this issue numerous times in past discussions with ARB staff and in formal written comments.

Nonetheless, the proposal remains included in the regulation even though no robust analysis or justification for the change has been presented. In Attachment C, ARB states the following:

This change will encourage pass through of program costs to industrial entities, thus incentivizing them to reduce emissions, while direct allocation will provide emissions leakage prevention in line with existing industrial allocation policy. This change will also remove the potential inequity between IOU-customer industrial covered entities, which already see a GHG cost and receive distribution of IOU auction proceeds to prevent against emissions leakage, and POU-customer industrial covered entities that may not be protected from emissions leakage.⁶¹⁸

These generalizations greatly overstate any potential inequities and do not consider the significant impacts that could occur for a POU with a high portion of its load coming from industrial covered entities. For POUs with sizable industrial load, the severe reduction in allowance allocations will inhibit the ARB's intended use of allowance allocations.

⁶¹⁸ Attachment C at 5.

Further, both electric rate structures and the ratemaking process for POUs are very complex. POUs may not always be able to simply adjust rates to ensure the added costs from the loss of these allowances will be directly passed on to only the covered industrial entities. The result is that these costs could be passed on to other POU customers.

By attempting to place “emissions leakage prevention in line with existing industrial allocation policy” at the same time that material reductions are occurring in industrial allocations is counter-intuitive to the goals being presented. This policy proposal has not been supported by staff analysis, and will create losses for both the utility and its industrial customers, regardless of size. POUs will lose allocation flexibility and revenue that has historically been used to protect the very industries that this policy is stated to help. As a result, the industrial entities in POU service territories could not only see a significant increase in their rates, but will also see dramatically decreased allocations from which to draw a counter benefit.

Any concerns that exist regarding unequal treatment between industrial entities in IOU and POU service areas should be discussed in detail during a workshop with all relevant parties. ARB should not take action until such a discussion has occurred, and several solutions have been publically evaluated. When coupled with the consignment proposal, the industrial allocation shift creates a double hit to POUs that has not been adequately evaluated by ARB staff. (CALMUNIUTILASSOC)

Comment:

SMUD opposes the proposal to reduce EDU allocations in relation to the amount of electricity supplied to industrial covered entities being served by each EDU. The intent of providing administrative allowances to EDUs was for ratepayer protection, to cover the obligations the EDUs pass on to their customers (in addition to the costs of complementary programs). The carbon obligation remains with the EDU for the electricity used by covered industrial customers, and EDUs are capable of passing the benefit of allocations to cover this obligation. There is no need for a complicated structure involving some industrial customers have the carbon obligation imbedded in electricity covered one way, while others are covered another way. And, since most industrial customers will not be compensated through the proposed new structure, administrative burden is not likely to be reduced by the proposal. The current structure should be maintained, where the allowances EDUs receive associated with emissions for generating electricity to serve retail load are not reduced for some but not all industrial customers, for the following reasons:

- Fairness and simplicity. All industrial customers have costs covered with the same structure, as opposed to one structure for covered entities and another for non-covered entities.

- The staff proposal would not cover actual carbon costs imbedded in electricity rates and returned to all customers (for POU's) as changes in the electricity mix change those costs over time.
- The current system reflects the cost differences between service areas in the state, the staff proposal does not – hence, the staff proposal may lead to unintended movement of industrial customers among utilities with no benefit to the atmosphere.
- It will be difficult to equate new industrial customer allowances with their actual emissions, which could lead to surplus allocations. Under the proposed rule industrial customers have no obligation to use those surplus revenues for AB 32 purposes, thus depriving the State of an important source of funding for carbon reduction.

In summary, SMUD opposes removing allowances from the EDUs and providing a related amount of allowances to covered industrial entities. The proposal is complicated and unnecessary. (SMUD)

Comment:

The allocation proposal described in Attachment C includes a reduction in allocated allowances “equivalent to the emission resulting from power that serves that EDU’s industrial covered entities.” NCPA continues to oppose this adjustment as not only unnecessary, but ultimately detrimental to the affected customers serviced by the POU's. As CARB found in 2011,

“Allocation to electricity utilities was chosen as the preferred method to return the allowance value to those affected by this program. Because most industrial facilities and Californians use electricity, returning allowance value via electricity utilities is the best alternative to reduce the cost burden of this program. We modified the regulation to include 95892 that demands electric utilities use allocation value to benefit ratepayers, which includes both industry and Californians.”⁶¹⁹

At that time, CARB also noted that the “CPUC and the POU governing boards will determine the most equal and fair way to redistribute the auction value back to its customers.”⁶²⁰ NCPA continues to believe that is the best way to ensure that the covered industrial customers receive the greatest total allowance value associated with their purchased electricity. Under CARB’s proposal, the transfer of allowances between the two sectors is not equivalent. As a result, the EDUs will not receive any allowances to cover the purchases electricity for their covered industrial customers, meaning that the full carbon price will need to be reflected in the customers’ rates. However, based on the current methodology, the allowances the covered industrial customers receive will not reflect this full value. In essence, the EDU’s covered industrial customers will

⁶¹⁹ 2011 FSOR, p. 567

⁶²⁰ FSOR, p. 590

see a diminution in their total allowance value when compared to the increased costs. NCPA is very concerned that this will detrimentally impact the economic viability of the very EITE entities that are supposed to be protected, and consequently the very communities in which they are located.

NCPA is also concerned that CARB's basis for proposing this change is based on a perceived problem that does not actually exist, as reflected in the reference to the "potential inequity between IOU-customer industrial covered entities, which already see a GHG cost and receive distribution of IOU auction proceeds to prevent against emissions leakage, and POU customer industrial covered entities that may not be protected from emissions leakage."⁶²¹ Just as electricity rates and services vary between the utilities, so to do the programs that are designed to provide GHG value to the electricity customers, including industrial covered entities. NCPA member EDUs may not have a uniform approach to returning allowance value to these customers, but such uniformity is not necessary to ensure that the customers receive value from the allocated allowances. The proposal to reduce the number of allowances allocated to the EDUs in this manner should be rejected. (NCPA)

Comment:

Shifting EDU Allowance Allocations to the Industrial Sector

ARB has proposed to discontinue the allocation to EDUs of the allowances associated with energy used at "energy intensive trade exposed" (EITE) facilities. Instead, the ARB proposal would allocate these allowances directly to EITE facilities, with the amount of the allowance allocation representing their electricity consumption and using a formula that includes Product-Based Benchmarks. ARB's stated purpose of this reallocation of allowances is to mitigate electricity cost increases for Cap-and-Trade Regulation compliance costs that would otherwise be borne by EITE sources by providing this supplemental allocation of allowances directly to those sources. Under this approach, ARB would "subtract from an EDU's allocation an amount equivalent to the emissions resulting from power that serves industrial covered entities that are customers of each EDU."

LADWP believes that ARB's proposal, as applied to publicly-owned utilities (POUs), is unlikely to accomplish ARB's goal of leakage prevention for the reasons described in LADWP's prior comment letter of September 19, 2016.⁶²²

LADWP again recommends that the most efficient and effective way to mitigate cost impacts to EITE facilities (and thereby avoid resulting leakage) is for the ARB to retain the current approach and not shift any allowances from EDUs to EITE sources, at least in the case of POUs, such as LADWP. (LADWP)

⁶²¹ Attachment C, p. 5, emphasis added.

⁶²² <https://www.arb.ca.gov/lists/com-attach/42-capandtrade16-UmsFLI1tUDoLIAQ1.pdf>

Comment:

C. The reduction in allocation to EDUs for sales to covered industrial entities should be eliminated

The proposal to reduce the number of allowances allocated to EDUs for industrial covered entities' purchased electricity should be removed from the EDU allocation methodology. Not only does this proposal represent a significant shift from the current policy, but the need for such a change has not been evidenced. M-S-R member agencies are concerned that the proposal results in an actual reduction in the total allowance value provided to their covered industrial customers, which could have adverse impacts on the companies and the communities they are located in. Based on the proposed allocation methodology, the covered industrial customers will not receive a 1:1 transfer of the allowances deducted from the EDU, but rather, will have that value reduced by their specific benchmarking, resulting in an actual reduction to their mitigation. This means that those customers will not be able to cover the increased electricity costs associated with the price of carbon with the allowances "transferred" from the EDUs to the industrial customers.

Additionally, M-S-R is concerned about the lack of specificity associated with the underlying justification put forth in Attachment C⁶²³ and claims that POU customers are disadvantaged or under-compensated. If specific instances do exist, those concerns about the use of allowance value should be addressed directly with the affected entities prior to moving to a draconian alternative with potentially adverse impacts for both the EDUs and the covered industrial customers. M-S-R member utilities return the allowance value to their customers, including the industrial covered entities, in the manner that best meets the needs of the utility's customers. This is exactly what was contemplated in 2011.⁶²⁴ Investments in programs and measures that advance the intent of AB 32 are already in place; reducing allowances for one class of electricity customers could result in diminishing the benefits of the allowance proceeds to remaining customers. M-S-R remains concerned that this proposal is misguided and urges the Board to direct staff to revise their EDU allocation proposal to exclude reductions based on covered industrial customers purchased electricity. Additionally, to the extent that CARB staff has specific concerns about the return of allowance value, M-S-R urges staff to notify those entities so that the issue can be reviewed and resolved. (M-S-R)

Response: Please refer to the response to 45-day comments B-1.16 which answers these comments. Staff notes that SFPUC has no industrial covered entities as customers and is unaffected by the amendment to redistribute allowances from EDUs to industrial covered entities.

⁶²³ Attachment C, p. 5.

⁶²⁴ "CPUC and the POU governing boards will determine the most equal and fair way to redistribute the auction value back to its customers." 2011 FSOR, p. 590.

B-1.19. Comment:

Reallocation of Allowances From the Electricity Sector to EITE Entities Should Be Done on a 1:1 Basis.

The ARB has proposed to update the EITE benchmarks to reallocate allowances from the electricity sector to the industrial sector. We believe this also requires further analysis. As a general matter, Praxair supports a direct allocation to EITE entities to account for GHG costs imbedded in electricity rates. However, we are concerned that utilities may develop new rate structures to account for the loss of Cap-and-Trade allowances attributable to a small subset of their ratepayers. Since the EITE assistance factors decline at a faster rate than the electricity sector allocations, GHG costs passed onto EITE entities in electricity rates may exceed the value of allowances EITE entities receive directly from the ARB post-2020. In order to avoid this unintended consequence, the ARB should ensure that allowances reallocated from the utility to the EITE entity are done on a one-for-one basis, and decline at a rate equivalent to the electricity sector's cap-decline-factor. To account for this unintended consequence, the portion of allowances reallocated to the EITE entities should be a separate allocation from the existing EITE allocations. In addition, the reallocation should be based on the emissions factor for the utility that actually serves the EITE customers, and not a system-wide emissions factor. (PRAXAIR)

Response: Please refer to the responses to 45-day comments B-1.16 and B-1.17, which answer this comment.

Use of Allocated Allowance Value

B-1.20. Comment:

SMUD supports including the prohibition of the use of allowance value to cover basic program costs (MRR, COI fees, etc.), in addition to the current prohibition of use to cover obligations from sales into the CAISO, as seen in the Proposed Amendments.

However, SMUD does not believe that there should be an explicit prohibition for POU's from returning allowance "proceeds" (the revenue from the sale of the allowances provided) in a volumetric fashion to ratepayers. ARB has stated that they do not intend to monitor or regulate POU rate structures or proceedings, nor do they intend to direct the CPUC's ratemaking authority on this issue. SMUD suggests that ARB should not establish an explicit prohibition that it does not have the intention to enforce, as that will likely just elicit market confusion.

At the very least, clarification is in order. POU's that consign allowances to auction are allowed to use the proceeds from those sales to purchase allowances, and are allowed to retire those allowances to cover their compliance obligation. The ARB should clarify that such retirement does not constitute "Returning allocated allowance auction proceeds in a volumetric manner..." and is not prohibited by Sections 95982(d)(3) and (5).

SMUD also suggests that the ARB consider a change to how consigned and unsold allowances are handled. Currently, these consigned allowances remain in the auction pool for sale at the next auction. SMUD suggests that ARB should allow the consigning entities to instead place unsold allowances directly into their compliance accounts. This change will address a problem faced by entities that are required to consign their allowances (IOUs) or that have chosen to do so (POUs, in some cases) when those allowances remain unsold for multiple auctions. The problem is that these entities continue to face compliance costs, but are delayed indefinitely in getting the auction revenue intended to offset those compliance costs. (SMUD)

Response: This comment is outside the scope of the first 15-day proposed regulatory changes. These subjects are addressed in response to 45-day comments B-1.21 and B-1.22.

B-1.21. Multiple Comments:

Specified Uses of Allowance Value. In Attachment C and in past meetings, ARB also expressed concern with certain uses of allowance value. SCPPA believes this is an unjustified concern, and that the proposed amendments in Section 95892 provide sufficient direction on how POUs may use allowance proceeds. ARB acknowledged at the beginning of the program that it “does not have authority to appropriate funds. The use of revenue obtained from consignment of allowances is the responsibility of the California Public Utilities Commission (CPUC) for investor-owned utilities and the governing Boards of publicly owned utilities.”⁶²⁵ SCPPA concurs that such decisions are fully under the authority of a POU’s local governing board, and are not decisions to be made by ARB. The current regulations appropriately acknowledge this authority, and that any attempt to circumvent ARB’s limited authority would be unlawful. SCPPA is willing to work with ARB after this current rulemaking is completed to see if there is common ground that can be found on this potential staff concern. However, ARB should consider offering additional clarification in the Final Statement of Reasons on what is meant by “non-volumetric” use of allowance value; though, any such clarification should not identify specific uses. (SCPPA)

Response: This comment is outside the scope of the first 15-day proposed regulatory changes. Non-volumetric use of allowance value is discussed in response to 45-day comments B-1.21.

POU Consignment of Allocation Allowances

B-1.22. Multiple Comments:

Provisions in the cap-and-trade program regulation regarding EDU consignment of allowances and use of auctions proceeds should not be altered. Attachment C states that “Staff is also considering requiring POUs and co-ops to consign allocated

⁶²⁵ See pages 65-66 of the October 2011 [Final Statement of Reasons](#) for the Cap-and-Trade Regulations.

allowances to auction and requiring that the auction proceeds be used for specific purposes” and notes that “additional proposed amendments would be proposed in a subsequent 15-day regulatory proposal.”⁶²⁶

The current distinction between the provisions regarding POU/co-ops and IOUs was based on an extensive record. In 2011, CARB acknowledged the different provisions, and noted that the distinction was justified because “POUs and IOUs operate differently with respect to electricity generation. POU generally own and operate generation facilities which they use to provide electricity directly to their end-use customers. In order to minimize the administrative costs of the program to the POU, and recognizing that directly allocating the allowances to the POU does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POU to surrender directly allocated allowances without participating in the auction process.”⁶²⁷ Furthermore, CARB acknowledged that all entities should have a reasonable means to comply with the cap-and-trade regulation in a manner that accommodates their respective business models and compliance strategies, and that imposing auction design features on vertically integrated POU is an unnecessary additional step that does not provide any value to POU electric ratepayers, nor to California overall.⁶²⁸ No changes are warranted, as the underlying rationale for the distinction remains unchanged.

Furthermore, NCPA notes that the scope of the current rulemaking does not include changes to the provisions regarding POU allowance consignment. Any such changes, even those intended to align use of allowance value among the different EDUs and natural gas suppliers, were not previously raised in the August 2 Proposed Amendments.⁶²⁹ If there is a desire on the part of the agency to amend the provisions of the regulation related to the consignment of allowances, that issue should be properly raised and noticed in a future rulemaking.⁶³⁰ Likewise, while the Proposed Amendments include changes to the provisions regarding the use of allowance value, those amendments are referred to as “clarifications” and are explicitly termed “nonsubstantive changes.”⁶³¹ To the extent that CARB is now contemplating substantive revisions or new rules surrounding the use of allowance value outside of what was identified in the August 2 Proposed Amendments, they would be outside the scope this rulemaking.

Given the already significant issues under consideration in this rulemaking, the inclusion of additional changes at this late date should be avoided. (NCPA)

⁶²⁶ Attachment C, p. 3.

⁶²⁷ 2011 FSOR, pp. 564-565.

⁶²⁸ 2011 FSOR, pp. 560-561.

⁶²⁹ It is telling that the Proposed Amendments did forecast changes to the provisions regarding the consignment of allowances for natural gas suppliers, yet makes no mention of consideration of consignment changes for EDUs. (August 2, 2016 Proposed Amendments, Initial Statement of Reasons, p. 45)

⁶³⁰ See Administrative Procedure Act, Govt Code section 11340, et seq.

⁶³¹ August 2, 2016 Proposed Amendments, Initial Statement of Reasons p. 40

Comment:

Allowance Use

Electric Cooperatives are concerned that CARB staff is considering prescriptive mandates for the use of the allowance value. Attachment C states:

“Staff is also considering requiring POU and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes. Requiring consignment would align the use of allowance value amongst investor-owned EDUs, publicly owned EDU, electrical cooperatives, and natural gas suppliers.”⁶³²

The EDUs are already restricted in the use of allowance value by the section 95892(d); regardless of the specific manner in which the cooperatives’ governing bodies direct the allowance value to be used, those uses must “be used exclusively for the benefit of retail ratepayers . . . consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.” Within those specific parameters, the ability of the cooperatives to use the allowance value has been a positive component of the Program for electric cooperatives. Not only do the three electric cooperatives differ greatly in their use of the allowance value, they are collectively significantly different than other EDUs, especially investor owned utilities. The flexible use is integral in recognizing the autonomous structure of democratically elected, local boards that make decisions in the best interest of their member-owners; not investors. The electric cooperatives do not believe it is prudent or good policy for CARB to prescribe additional restrictions on the use of allowance value. Indeed, doing so would more likely adversely impact EDU ratepayers as CARB attempts to mandate one-size-fits-all restrictions on the use of allowance value.

Electric cooperatives serve rural consumers; the infrastructure cost to serve less than five members per mile of power line is a challenge that shouldn’t be ignored. Electric cooperatives are different, and it is imperative that we are afforded a magnitude of flexibility so that we are able to keep electricity service affordable for the rural Californian.

Furthermore, the electric cooperatives are concerned that CARB is raising this issue for the first time in the context of 15-day changes to the originally proposed amendments. The August 2, 2016 regulatory documents did not raise this issue, except to include a new provision regarding the time during which the allowance value must be used. Indeed, CARB’s explanation of the proposed amendments to section 95892 specifically referred to the changes as “nonsubstantive.” Based on that characterization and the fact that no reference was made to potential further revisions in the original rulemaking materials, the cooperatives do not believe that this issue is properly within the scope of the current rulemaking. (GOLDENSTATEPOWER)

⁶³² <https://www.arb.ca.gov/regact/2016/capandtrade16/attachc.pdf>

Comment:

4. Suggested amendments to EDU consignment provisions and rules for use of allowance value should not be changed in this rulemaking

In discussing the allocation proposal, the 15-Day Changes states that “Staff is also considering requiring POU and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes” and that “[a]dditional proposed amendments would be proposed in a subsequent 15-day regulatory proposal.”⁶³³ M-S-R was surprised to see this reference in Attachment C, as there have been no market or regulatory changes that would warrant a corresponding change to the consignment provisions. Further, as this issue was not previously raised in the context of the August 2, 2016 proposed amendments, any changes to provisions regarding EDU consignment of allowances would be outside the scope of this rulemaking.

The provisions of section 95892(b) were the subject of extensive deliberations during the 2010-2011 rulemaking process. The final rule reflects the significant structural differences between the vertically integrated POUs and the IOUs, and ensures that POU electricity ratepayers would not have to incur needless administrative costs by consigning all of their allowances into an auction when they own or operate their own generation resources to provide electricity directly to their end-use customers.⁶³⁴ Requiring the POUs to do so would only increase compliance costs and decrease the amount of allowance value available to directly benefit the electricity ratepayers. Since that time, there have been no changes to the regulatory structure or legislative mandates that alter the underlying rationale or justification upon which the current consignment rules are based. In the absence of such changes, M-S-R does not believe that any changes to the regulation are warranted.

Further, the scope of this rulemaking, as set forth in the August 2, 2016 Staff Report, did not raise EDU consignment in any manner. Changes to consignment provisions for gas utilities were proposed.⁶³⁵ Accordingly, while the 15-Day Changes modify the original consignment proposal for gas utilities, that is appropriate given that the issue was raised as one being considered in this rulemaking. It would be inappropriate – and unlawful⁶³⁶ – for the 15-Day Changes to include amendments to provisions that were not previously noticed. Had staff also contemplated changes to the EDU consignment provisions, they similarly could have raised the issue at that time. However, since changes to EDU consignment rules was not included in the August 2, 2016 scope of proposed amendments under consideration, any changes to the program rules in this regard would need to be taken up in a subsequent rulemaking.

⁶³³ Attachment C, p. 2.

⁶³⁴ 2011 FSOR, pp. 564-565.

⁶³⁵ August 2, 2016 Staff Report, Initial Statement of Reasons, p. 45.

⁶³⁶ Government Code section 11346.8(c).

Attachment C also notes that staff is considering “requiring that the auction proceeds be used for specific purposes.” To the extent that additional proposed amendments are contemplated that address “specific purposes” for the use of allowance value that are not already part of section 95892(d) or addressed in the August 2, 2016 Staff Report, those amendments are not appropriately part of the current rulemaking. Potential changes to the provisions regarding the use of allowance value included a proposed amendment to section 95892(d) adding a deadline to the use of allocated allowance value and a requirement that the allowance value be returned on a non-volumetric basis, citing consistency with the restrictions placed on natural gas suppliers.⁶³⁷ Other than these explicit amendments, the Staff Report notes that “Proposed changes to the Regulation would also make several clarifications to the allowed uses of [EDU] allocated allowance values. . . . These amendments are not substantive changes, but clarifications to the meaning of benefiting ratepayers and consistency with AB 32 goals.”⁶³⁸ Any further revisions or changes to the regulations to restrict the use of allowance value “for specific purposes” would go beyond the scope of amendments discussed in the initial rulemaking materials and there would not be appropriate for the current rulemaking.

Had amendments to the rules governing EDU consignment and further restrictions on the use of allowance value been contemplated but not fully developed, those issues should have been referenced in the August 2, 2016 Staff Report and Initial Statement of Reasons in a similar manner as other issues were raised.⁶³⁹ Absent the inclusion of these issues in the original rulemaking, or notice to stakeholders that this matter may be the subject of a subsequent 15-day regulatory proposal in the initial rulemaking materials, those matters are not properly included in the 15-Day Changes or any subsequent 15-day amendments in this current rulemaking. M-S-R urges staff not to expand the scope of this rulemaking at this time, but rather continue to work with stakeholders on resolution of the critical issues that are already being addressed. (M-S-R)

Comment:

Any changes to EDU allowance consignment would be outside of the scope of the current rulemaking process. In Attachment C to the 15-Day Changes, ARB states that they are, “considering requiring POU and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes.” The unique, vertically integrated and locally controlled nature of POU and co-ops led the original program to be set up so that those entities are allowed the flexibility to use allocated allowances directly towards their compliance obligations or to fund emission

⁶³⁷ August 2, 2016 Staff Report, Initial Statement of Reasons, p. 40.

⁶³⁸ *Id.*

⁶³⁹ There are several references in the August 2, 2016 Staff Report to items that staff was still reviewing at that time, noting that “any proposed revisions would be circulated for a 15-day comment period.” In this way, stakeholders were made aware of the scope of potential amendments, even in instances where the specific regulatory language had not yet been developed.

reduction projects. Nothing has changed in how POU's operate that would justify reducing their options for satisfying their compliance obligation in the most cost-effective manner. Furthermore, this issue has not been addressed in the rulemaking so far, and should be considered outside the scope of the rulemaking. MID requests that this issue not be included in subsequent 15-day amendments, the current rulemaking is already populated with a large amount of complicated and impactful changes and does not lack for more. (MODESTOID)

Comment:

The ARB should retain the option for POU's to consign all allowances to auction. We are also concerned by the potential for prescriptive ways of spending the revenue. ARB correctly recognized in the 2010 Program design the inherent differences between POU's and IOU's. POU's are typically vertically integrated, and fully resourced, and were never deregulated in the manner in which IOU's were. As noted in the October 2011 FSOR:

"POUs and IOUs operate differently with respect to electricity generation. POU's generally own and operate generation facilities that they use to provide electricity directly to their end-use customers. In order to minimize the administrative costs of the program to the POU's, and recognizing that directly allocating the allowances to the POU's does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POU's to surrender directly allocated allowances without participating in the auction process. IOUs, on the other hand, have contracts with electricity generators that do not afford the IOUs the same level of control over the capital investments and operating decisions of the generation facility. We are concerned that the terms of these contracts could be adversely affected by allowing the IOUs to directly surrender allowances on behalf of their counterparties, which could lead to some foregone cost-effective emissions reductions. Instead, by requiring the IOUs to surrender the allowances at auction, the electricity generators will be sure to have a strong incentive to pass their GHG costs back to the IOUs, who will then be able to use their share of the auction revenue to reduce the ratepayer burden in a manner that is consistent with the goals of AB 32."⁶⁴⁰

TID sees no compelling reason to require the consignment of allowances. POU's are focused on compliance, and one of the stated reasons for free allocations is to shield electric ratepayers from the cost of the Cap & Trade program. The POU is uniquely situated to pass any allowance value onto the ratepayers. Requiring the sale of allowances and crafting prescriptive measures for revenue usage will require POU's to raise rates on the very ratepayers that the allowances were designed to protect. (TURLOCKID)

⁶⁴⁰ See page 342 of the October 2011 Final Statement of Reasons for the Cap and Trade Regulations

Comment:

In Attachment C of the Proposed 15-Day Modifications, ARB staff notes that it is considering “requiring POUs and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes.”⁶⁴¹ ARB staff asserts that such changes could be presented in future 15-day language.

This is a significant new proposal that could have wide-ranging harmful impacts, and yet, this is the first time ARB staff has raised this proposal. Such a substantial change should only be proposed in 15-Day Language if it is “sufficiently related to the original text that the public was adequately placed on notice that the change could result from the originally proposed regulatory action.”⁶⁴² This proposal is likely outside the scope of this proceeding, and CMUA is not aware of any previous discussion or related proposals in the 45-day package that would have put the public on notice that it may be proposed. Furthermore, the discussion included in Attachment C does not provide adequate justification or reasoning for revisiting this impactful shift in policy.

In addition to these procedural concerns, CMUA objects to the policy and rationale for requiring POUs to consign their allowances to auction. In prior Rulemakings, ARB correctly excluded POUs from the requirement to consign allowance allocations to auction, as is required of investor owned utilities (“IOUs”), because of the fundamental differences in the way that IOUs and POUs are structured and governed. ARB noted these differences in its October 2011 Final Statement of Reasons for the Cap-and-Trade Regulations (“FSOR”)⁶⁴³:

*POUs and IOUs operate differently with respect to electricity generation. POUs generally own and operate generation facilities that they use to provide electricity directly to their end-use customers. In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive to make costeffective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process.*⁶⁴⁴

ARB also acknowledged that some POUs would be disproportionately impacted if they were required to participate in the quarterly auction.⁶⁴⁵

A requirement for POUs to consign all allocated allowances could impose significant financial risks and resource needs that cannot reasonably be addressed. This change would result in significant increases in administrative burdens. Many POUs have limited staff to participate in the resource-intensive auction process, and do not have the

⁶⁴¹ Attachment C at 2.

⁶⁴² Cal. Gov. Code § 11346.8(c).

⁶⁴³ See e.g., October 2011 Final Statement of Reasons for the Cap and Trade Regulations, 342, 564.

⁶⁴⁴ *Id.* at 342.

⁶⁴⁵ *Id.* at 578-579, 580-581.

infrastructure or financial resources to mitigate against financial exposure in the same way that IOUs can.

Because POU's often own and operate generation facilities, they have the direct compliance obligation for the assets under the Program. Due to long-term contracts with base-load, fossil-fueled generation including both coal and natural gas, some POU's would be required to have significant capital available to purchase sufficient allowances from auction to comply with the Regulations. These burdens would disproportionately affect some POU's more than others.

If the Cap-and-Trade auctions are undersubscribed or oversubscribed, POU's will face substantial financial risks that may impede their ability to meet compliance obligations due to the resulting financial uncertainties. Unlike the IOUs, POU's do not have shareholder funding to fall back on if there are challenges with auction participation. Any additional cost burdens incurred by POU's to manage compliance with the Cap and Trade requirements could negatively impact the ratepayers served by POU's, while achieving no measurable, incremental GHG emissions reduction benefits...

As noted above, ARB Staff stated that they are considering "requiring that the auction proceeds be used for specific purposes."⁶⁴⁶ The currently applicable requirements in Section 95892 provide sufficient direction on how POU's may use allowance proceeds. Further, the ARB acknowledged at the beginning of the program that it "does not have authority to appropriate funds. The use of revenue obtained from consignment of allowances is the responsibility of the California Public Utilities Commission (CPUC) for investor-owned utilities and the governing Boards of publicly owned utilities."⁶⁴⁷ CMUA concurs that such decisions are fully under the authority of a POU's local governing board, and are not decisions to be made by ARB. (CALMUNIUTILASSOC)

Comment:

Consignment of Allowances:

The current regulation allows Publicly Owned Utilities (POUs) the flexibility to comply with the Cap and Trade Program through the distribution of allowances directly to the POU's compliance account, or through the consignment procedure. PWP considers the continuance of this distribution process as appropriate, as this ensures that allocated allowances are used "exclusively for the benefit of the retail ratepayers", consistent with AB 32 legislation.

CARB staff's, Attachment C of the Allowance Allocation to EDUs states that "Staff is also considering requiring POU's and co-ops to consign allocated allowances to auction and requiring that auction proceeds be used for specific purposes".

⁶⁴⁶ Attachment C at 2.

⁶⁴⁷ October 2011 Final Statement of Reasons for the Cap-and-Trade Regulations, 65-66.

Publicly Owned Utilities are vertically integrated with owned generation capacity along with contracted renewable resources that meet or exceed our current and projected future sales. A regulatory mandate that requires POU's to fully consign allowances for auction exposes them to a significant financial risk and rate impacts. In instances when the supply of allowances is less than the demand, POU's may be unable to secure a sufficient amount of allowances to meet its obligation. It is difficult for POU's to shoulder the financial unpredictability.

Additionally, it is incorrect to assign proceeds for a specific use, because the regulation already places limitations on the allowances and auction proceeds to ensure that AB 32 requirements are carried out. Imposing a "specific use" clause would be regulatory overreach as the POU's governing board has the authority over utility investments into GHG reducing technologies. Such a severe change in regulatory direction could effectively negate the underlying reasons for many resource portfolio decisions made by POU's. (PASADENA)

Comment:

Publicly-Owned Utility Use of Allowances for Compliance

Enclosure C: 2021-2030 Allocation to Electrical Distribution Utilities states that ARB staff is "considering requiring POU's and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes. Requiring consignment would align the use of allowance value amongst investor-owned EDUs, electrical cooperatives, and natural gas suppliers." LADWP strongly opposes any proposal that would require POU's to consign its allocated allowances to auction.

ARB consideration of this alternative runs counter to ARB's long-standing policy on the use of allowances by POU's, which ARB recently affirmed in its August 2016 proposal to continue to permit POU's to directly use allocated allowances for the post-2020 compliance period. Unlike IOUs, POU's operate for the exclusive benefit of their retail ratepayers and own and operate their generation assets on behalf of their retail ratepayers. POU-owned generation also is generally used only to serve POU ratepayers as part of a vertically integrated electric utility system. Unlike IOUs, POU's do not have subsidiaries that can profit from selling power on the market from their merchant generators. Thus, not-for-profit POU's have no incentive to use allowance allocations to artificially lower the price of the power from their own resources in order to increase market share. Rather, they have a legal obligation to serve their communities and customers by providing reliable and clean electricity at the most affordable cost. Therefore, the concerns that led to ARB's 2010 decision to require IOUs to consign allowances to auction continue not to apply to POU's.⁶⁴⁸

⁶⁴⁸ ARB, Staff Report: Initial Statement of Reasons at IX-62 (Oct. 28, 2010), <https://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf> [hereafter "2010 ISOR"] ("Rational for Section 95892(c). Monetization of allowances through auction is intended to ensure that the amount of

LADWP agrees with ARB's rationale for allowing POUs to surrender directed allocated allowances without consigning their allowances to auction.⁶⁴⁹ Excerpts from ARB's 2011 Final Statement of Reasons in support of this approach are outlined below:

- IOUs and POUs operate differently with respect to electricity generation.
- POUs generally own and operate generation facilities that they use to provide electricity directly to their end-use customers. ARB also acknowledged that if POUs consigned their allowances, they would be required to sell and repurchase their own allowances.
- IOUs compete in an open market for electricity with their own generation and third party generators. In order to ensure that independent generators have equal access to allowances, IOUs are required to auction their allowances.
- By requiring IOUs to consign allowances at auction, the electricity generators will be sure to have a strong incentive to pass their GHG costs back to the IOUs who will then be able to use their share of auction revenues to reduce ratepayer burden consistent with the goals of AB 32.
- Directly allocating allowances to POUs does not distort their economic incentive to make cost-effective emissions reductions.
- Whether auctioned or not, the price of carbon affects decisions to emit. Even though POUs are not required to consign allowances, they are required to use that value for ratepayer benefit and no other purposes. This is equitable with the requirements on the IOUs.

The requirement for POUs such as LADWP to consign their allowances to auction would result in the following adverse impacts:

- Increased staff time related to participation in the auctions
- Risk that LADWP will not be successful in purchasing all of its allowances back if the auction is oversubscribed. LADWP would have to bid more in subsequent auctions, purchase allowances through the secondary market and pay

value given to distribution utilities is transparent to the public, and that this value is used on behalf of electricity ratepayers. This practice will also ensure that freely allocated allowances to a distribution utility will not impact competition in the electricity generation market (where utilities compete with merchant power producers) ") *Id.* at II-32 ("By requiring IOUs to put their allowances up for auction, the regulation maintains the current competitiveness of the deregulated California electricity market. In this way, utility owned generation and independent generation have equal access to allowances."); ARB, Final Statement of Reasons at 342 (Oct. 2011), <https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf> [hereafter "2010 FSOR"] ("In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process.")

⁶⁴⁹ ARB Final Statement of Reasons, California Cap-and-Trade Program, October 2011

commission fees, or participate in ARB's reserve auction (at prices at least \$60 above the auction reserve price) if auction allowances are exhausted.

- Increased transactional costs resulting from payment of commission fees and/or bid guarantees that would limit LADWP's ability to mitigate the cost burden on ratepayers for no corresponding environmental benefit.
- Risk that LADWP would be at a significant deficit if the auction is unsubscribed. LADWP would purchase its needed allowances which would be a significant outflow of money but would receive significantly less auction proceeds.
- Increased cost associated with getting bid guarantees for the purchase of allowances.

Enclosure C also states that ARB staff is considering that POU's use the auction proceeds "for specific purposes." In discussions with POU's, ARB staff has also expressed concern with certain uses of allowance value. LADWP has committed to investing in programs to meet the City of Los Angeles' strong environmental goals which are beyond regulatory requirements. For example, LADWP committed to a 33 percent RPS goal by 2020 before that State goal was established, committed to a 15 percent energy efficiency goal by 2020 (beyond the 10 percent State mandate), and is providing residential and commercial electric vehicle incentives in the amount of \$21.5 million (2016 to 2018 time period). LADWP believes that its local policymakers are in the best position to know how to use the value of its allowances in order to achieve GHG emission reductions. (LADWP)

Comment:

Concern with ARB Staff Proposals to Reverse Previous Policy Decisions Recognizing the Differences between Publicly-Owned Utilities and Investor-Owned Utilities. SCPPA and its Members are increasingly concerned with ARB Staff's concerted and multi-pronged efforts to treat POU's and IOU's as a single type of entity. They simply are not. The two utility types are fundamentally different in objectives, resource procurement mix, financial structures, and governance.

These differences are statutorily directed and were previously acknowledged by ARB when the Program was initially developed. Yet, there has been a consistent theme in this rulemaking process to prescribe uniform policies to these disparate entities.

We recognize the value and importance of having as even a playing field as possible across Program entities. However, treating public utilities the same as investor-owned utilities is not the way to achieve this goal. Just as there are differences in regional generation make-up that define the impact of the regulations on a particular utility and the different objectives amongst the state agencies (e.g., ARB versus CEC), the differences between IOU and POU customers cannot be understated. ARB should acknowledge the differences between POU's and IOU's, and should refrain from pushing POU's to an IOU Cap-and-Trade model. In the past we have noted several important

examples of why such a shift is not needed and will cause undo costs and hardships under the Program without achieving any additional environmental benefits. We continue to raise similar points in this letter.

POU Consignment of Allowances. Attachment C in the Cap-and-Trade regulatory package states:

“Staff is also considering requiring POU and co-ops to consign allocated allowances to auction and requiring that the auction proceeds be used for specific purposes. Requiring consignment would align the use of allowance value amongst investor-owned EDUs, publicly owned EDU, electrical cooperatives, and natural gas suppliers. Additional proposed amendments would be proposed in a subsequent 15-day regulatory proposal.” [emphasis added]

SCPPA and its Members do not agree with the policy approach and reasoning presented in the attachment. We STRONGLY OPPOSE any modifications to the regulations to require POU to consign allowances to auction. ARB has historically exercised sound reason in its decision to exclude POU from the requirement to consign allowance allocations to auction, as is required of IOUs; IOUs and POU are neither structured nor governed the same way. This historic rationale is still valid.

A requirement for POU to consign all allocated allowances could introduce sizable financial risks and resource needs that cannot reasonably be addressed, would be administratively inefficient, and would disproportionately affect some POU more than others. Many POU have limited staff to participate in the resource-intensive auction (carbon market) process, and do not have the infrastructure or financial resources to mitigate against financial exposure in the same way that IOUs can. ARB, in fact, stated in its October 2011 Final Statement of Reasons for the Cap-and-Trade Regulations (FSOR)⁶⁵⁰:

“POU and IOUs operate differently with respect to electricity generation. POU generally own and operate generation facilities that they use to provide electricity directly to their end-use customers. In order to minimize the administrative costs of the program to the POU, and recognizing that directly allocating the allowances to the POU does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POU to surrender directly allocated allowances without participating in the auction process. IOUs, on the other hand, have contracts with electricity generators that do not afford the IOUs the same level of control over the capital investments and operating decisions of the generation facility. We are concerned that the terms of these contracts could be adversely affected by allowing the IOUs to directly surrender allowances on behalf of their counterparties, which could lead to some foregone cost-effective emissions reductions. Instead, by requiring the IOUs to surrender the allowances at auction, the electricity generators will

⁶⁵⁰ See pages 342 and 564 of the October 2011 Final Statement of Reasons for the Cap and Trade Regulations.

be sure to have a strong incentive to pass their GHG costs back to the IOUs, who will then be able to use their share of the auction revenue to reduce the ratepayer burden in a manner that is consistent with the goals of AB 32.” [emphasis added]

As ARB is aware, POUs, including SCPPA’s Members, are vertically integrated, meaning that they often own or operate much of their generation and transmission assets that serve customers. In the regulations adopted in 2011, as well as specifically noted in the October 2011 FSOR651, ARB correctly acknowledged that some POUs would be disproportionately impacted if they were required to participate in the quarterly auction. Because POUs own and operate generation facilities, they have the direct compliance obligation for the assets under the Program. Due to long-term contracts with fossil generation including both coal and natural gas, some POUs, particularly SCPPA Members, would be required to have significant capital available (including transaction costs) to participate in auctions to purchase allowances that would be required for compliance. If auctions are undersubscribed, as demonstrated in this past year, or oversubscribed, POUs will face substantial financial risks that may impede their ability to meet compliance obligations due to the financial uncertainties that result. POUs do not have shareholder funding to fall back on if there are auction challenges. Any additional cost burdens incurred by POUs to manage the Cap & Trade Program, including mitigating the aforementioned financial risks associated with the consignment requirement (assuming such mitigation measures even reasonably exist), may negatively impact POUs’ ratepayers, while achieving no measurable incremental GHG reduction benefits. (SCPPA)

Response: The commenters request that POUs continue to not have a consignment requirement and not be required to use their auction proceeds for specific purposes. Staff agrees that changes to POU consignment are outside the scope of the current rulemaking. Changes to the use of auction proceeds are also outside the scope of the first 15-day proposed regulatory changes. These topics are discussed in responses to 45-day comments B-1.20 and B-1.29.

Miscellaneous

B-1.23. Comment:

NCPA fully supports CARB’s recommendation to continue to provide EDUs with allowances for the benefit of their electricity customers. NCPA supports use of an allowance allocation methodology that would assign allowances for the entire period 2021 to 2030, reflecting the period covered by the current GHG Allowance budget. (NCPA)

Response: Thank you for the support.

⁶⁵¹ See pages 578-579 and 580-581 of the October 2011 Final State of Reasons for the Cap-and-Trade Regulations.

B-1.24. Multiple Comments:

PG&E also supports several of the technical adjustments that are incorporated in this proposal.

This includes calculating RPS energy based on retail sales (per statute) and not energy for load. It also includes utilizing the California Energy Commission (CEC) load forecast that does not include additional achievable energy efficiency (AAEE). These adjustments strengthen this proposal and should be maintained. (PG&E)

Comment:

SCE supports key changes made in these 15-day Modifications. SCE supports the amendments in the 15-day language that ensure the Renewables Portfolio Standard (RPS) component of the allowance allocation computation is applied to retail sales and not 'load including losses', which is consistent with the way compliance is calculated for the RPS Program. SCE also supports ARB's proposal in the 15-day language that bases the allocation calculation on demand forecasts that do not include additional achievable energy efficiency (AAEE). Finally, SCE commends CARB for ensuring that this proposed EDU allocation methodology will be in effect throughout the 2021-2030 period. (SOCALEDISON)

Comment:

Proposed Use of Mid-Demand Baseline Forecast Scenario

LADWP supports ARB's application of the CEC's 2015 Demand Forecast's Mid-Demand No Additional Achievable Energy Efficiency (AAEE) forecast scenario. Since AAEE is defined as future energy efficiency programs that are not yet approved or funded, LADWP believes that it is appropriate to not include AAEE in the allowance allocation methodology. (LADWP)

Response: Thank you for the support.

B-1.25. Comment:

PG&E filed extensive comments on the EDU allocation topic on November 4, 2017, which are here incorporated by reference.⁶⁵² In particular, we reiterate that maintaining a reasonable allocation to EDUs is a critical component of a broader strategy to ensure equitable impacts for California households.

PG&E thanks ARB staff for incorporating several recommended changes in this 15-day package to better reflect EDU cost exposure and protect California households. Specifically, staff is to be lauded for recognizing PG&E's proposed retirement of Diablo Canyon Power Plant (DCPP) and for utilizing a consistent replacement assumption that maintains incentives for voluntary overcompliance with California's Renewables

⁶⁵² *Ibid.* p 7-10.

Portfolio Standard (RPS). While some technical suggestions for improvement to that provision are described later, ARB's proposed framework for addressing retirement of coal and nuclear plants is sound. (PG&E)

Response: Thank you for the support.

B-1.26. Comment:

2021-2030 Electrical Distribution Utility Allowance Allocation

LADWP appreciates ARB efforts to provide a fuller picture regarding the proposed allowance allocation methodology, including proposed year-by-year allowance allocations for each Electrical Distribution Utility (EDU). LADWP continues to support the consumer cost burden allocation methodology that has enabled the electric sector to meet the state emission reduction targets without imposing undue adverse impacts on ratepayers. LADWP is concerned that certain features of ARB's current proposal do not fully reflect the goals of its approach. LADWP recommends a limited set of changes to more fully harmonize the proposal with ARB's stated goals...

ARB's Proposed "Change Load" Approach

In the October 14, 2016 informal staff proposal,⁶⁵³ ARB staff proposed two options for calculating post-2020 EDU allowance allocations: 1) assume that EDUs' loads change as projected in the 2015 California Energy Commission (CEC) Demand Forecast and assume loads would be fixed at 2020 levels. LADWP appreciates ARB staff's recognition, in this proposal,⁶⁵⁴ that there would be EDU service territories that would have loads that increase post-2020 and supports ARB staff's proposed approach to calculate the cost burden based on anticipated load changes instead of keeping load fixed over the 2021-2030 period. calculation of each individual EDU's allowance allocation using each EDU's projected load level is a reasonable approach that would account for growth and increased load due to increased electrification of sources and other expected electricity demand growth in the EDU's service territory. (LADWP)

Response: The commenter expresses support for the use of changing loads when calculating EDU allocations. Thank you for the support.

B-2. Natural Gas Suppliers

Consignment Requirement

B-2.1. Multiple Comments:

Support Current Consignment Level Increases of 5% per year

⁶⁵³ Cap-and-Trade Regulation, Post-2020 Allocation to Electrical Distribution Utilities, Informal Staff Proposal, dated October 14, 2016.

⁶⁵⁴ ARB Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation First Notice of Public Availability of 15-Day Amendment Text Enclosure C (Dec. 21, 2016) [hereinafter "Enclosure C"]

SoCalGas maintains that the current 5% annual increase in required allowance consignment levels for natural gas suppliers is the most prudent way forward. The most recent changes to the Cap-and-Trade Amendments propose full consignment starting in 2021. While SoCalGas does not object to the goal of reaching full consignment earlier than 2030, the sudden and aggressive acceleration to 100% consignment would cause substantial rate increases, which would be punitive to our customers, without delivering the reductions in emissions that ARB anticipates. In the supplemental material referred to as “Attachment D,” ARB makes several arguments for starting 100% consignment in 2021. In the following paragraphs, we attempt to summarize and address them, and demonstrate why introducing a price signal with gradual consignment, the approach used between 2015 and 2020, is more sensible and effective.

Attachment D addresses post-2020 natural gas supplier consignment requirements and offers the following four major reasons to radically accelerate the consignment to 100%: 1) it will drive conservation, 2) it will lead to equitably distributed costs, 3) it will drive electrification, and 4) it will result in reduced fugitive emissions. ARB’s arguments are not supported by the facts as demonstrated below.

1. ARB acknowledges that higher consignment will lead to higher costs passed-through to consumers, but that this will result in less natural gas use thereby decreasing household emissions by “40 to 50 kg CO₂e” in 2021, the first year of the policy change. ARB argues that commercial and industrial sectors would reduce their emissions even more. As evidenced by well-respected energy efficiency studies and through SoCalGas’ own observations and resource planning activities, natural gas price increases appear to have little short-term effect on consumption behavior in the retail market.^{655,656,657}

The price elasticities that ARB used to derive the emission reduction values are four to fifteen times higher than existing national, regional and state-specific studies of the natural gas short-run price elasticity.⁶⁵⁸ For comparison, the CEC Demand Analysis Office used the following price elasticities for the 2014-2024 California Energy Demand Forecast:⁶⁵⁹

⁶⁵⁵ California Climate Change Center, *Price Impact on the Demand for Water and Energy in California Residences*, (CEC-500-2009-032-F) (2009).

⁶⁵⁶ Bernstein, M.A., Griffin, J., *Regional Differences in the Price-Elasticity of Demand for Energy*, National Renewable Energy Laboratory, (Subcontract Report NREL/SR-620-39512) (2006).

⁶⁵⁷ U.S. Energy Information Administration, *Price Elasticities for Energy Use in Buildings of the United States*. (2014).

⁶⁵⁸ The CEC/CCCC paper (footnote 3 above) noted a price elasticity value in the Pacific census division to be -0.12; the NREL paper (footnote 4 above) found California residential short-run elasticity to be -0.098; EIA study found average short-run elasticities (avg. years 1-3) for residential sector to be -0.09; and the CEC Demand Analysis Office used residential elasticity of -0.035 for the California Energy Demand 2014-2024 Final Forecast (footnote 7 below).

⁶⁵⁹ See page A-9 of California Energy Commission. *California Energy Demand 2014-2024 Final Forecast. Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency*. (CEC-20002013-004-V1CMG). 2014.

Table A-6: Price Elasticities of Demand by Sector, *CED 2013 Final*

Sector	Electricity	Natural Gas
Residential	-0.08	-0.035
Commercial	-0.15	-0.15
Industrial: Manufacturing	-0.17	-0.11
Industrial: Resource Extraction and Construction	-0.10	-0.02

Source: California Energy Commission, Demand Analysis Office, 2013.

The logic behind using long-term elasticities to calculate same-year demand changes is flawed (see footnote 7 of Attachment D), leading to inflated emissions savings purportedly realized beginning in year 1 of the policy change (year 2021). ARB's analysis applied long-run elasticities to calculate short-term effects, vastly overstating the short-run impacts. A gradual change in consignment, if known in advance, should supply the same long-run effects, without the potential for rate shock.

2. Attachment D states that accelerating full consignment will achieve equitable GHG costs between consumers and across sectors. While SoCalGas can understand the intent behind this thinking, in practice full consignment will likely exacerbate the disproportionate impact to residential vs. non-residential ratepayers. For example, Capand-Trade costs are imposed on all customer classes volumetrically; however, Cap-andTrade revenues are returned to customers non-volumetrically through the Climate Credit with the specific customer classes eligible to receive the Climate Credit currently being determined by the California Public Utilities Commission ("CPUC").⁶⁶⁰ Therefore, a full consignment scenario increases the cost of compliance for everyone volumetrically then redistributes the consignment proceeds to certain customers non-volumetrically, thereby creating disproportionate rate impacts.

As stated previously, SoCalGas is supportive of gradually reaching full consignment, but jumping to 100% over-night may place a needless and severe hardship on the state's nonresidential customers, such as small businesses, non-profits and industry, who will bear the cost burden, but will not benefit from consignment proceeds in the same way that residential customers will under a non-volumetric return of revenue regime, as proposed by the CPUC.

ARB also makes the assertion that partial consignment incentivizes fewer GHG emissions reductions from the natural gas supplied sector and leaves other sectors to accomplish those reductions. As stated in Item 1 above, increased cost pass-through resulting from full consignment will increase economic hardship on individual natural

⁶⁶⁰ CPUC Decision 15-10-032 directs natural gas investor owned utilities to return consignment proceeds to residential ratepayers as an annual Climate Credit. Subsequently, the CPUC has granted a limited rehearing of the Decision in the GHG Natural Gas OIR Rulemaking 14-03-003 to discuss the California Manufacturers & Technology Association's application for rehearing, resulting in a temporary suspension of Cap-and-Trade cost recovery and Climate Credit activity.

gas customers while having little effect on short-run GHG reductions. The same long-run reductions can be achieved with a known path of consignment reductions. It is also noted that fully 25% of the electric sector has no consignment requirements at all (publicly – owned electric distribution companies), so that a 5% decline will match the average consignment amounts in the same time period to 2030.

3. ARB explains that full consignment is also a means to encourage fuel switching from natural gas to electricity. Increasing the costs of operating natural gas appliances would be harmful to customers who currently use or prefer to use natural gas appliances, especially to those, such as tenants, who cannot make changes to building hot water and heating equipment, the two predominant end-uses of natural gas in the residential and commercial sectors.⁶⁶¹

Furthermore, it is far from a foregone conclusion that electric end-use appliances are lower GHG emitters than natural gas appliances in the near to mid-term. Currently, “end-use natural gas appliances most often represent a lower GHG emissions alternative because their efficiencies are higher than power plants, avoiding energy lost in the conversion of heat (from natural gas combustion at a power plant) to electricity and back to heat. End-use natural gas appliances also avoid the major transmission and distribution losses that are inherent in the electricity system.”⁹

Moreover, moving to electric appliances presupposes that renewable natural gas (“RNG”) will never materialize. SoCalGas is optimistic about the role RNG will play in supporting the state’s ambitious SB 32 GHG reduction target. SoCalGas has also been actively engaged in the development of the 2030 Target Scoping Plan and in advocating for actions and policies to increase RNG utilization.

In addition to the environmental benefits of near-term natural gas appliances and longterm RNG, it has been documented that consumers prefer having natural gas in their home. A recent study concluded that mixed-fuel homes have cost and consumer preference advantages over electric-only homes.⁶⁶² ARB should not limit consumer choice, and should remain fuel and technology agnostic.

4. A final argument that ARB provides for accelerating the consignment requirements to 100% in 2021 is to reduce fugitive methane emissions. However, given how low natural gas demand elasticities are (as shown above in Item 1), the impact of raising natural gas prices on fugitive emissions in the near term may not be significant. Therefore, fugitive emissions should not be a foundational consideration for amending Program

⁶⁶¹ Renters comprise of over 50% of all property occupants in Los Angeles County. US Census Bureau, 2012

American Community Survey. For predominant natural gas end uses, see 2009 California Residential Appliance Saturation Survey, KEMA, Inc., October 2010 and the California Commercial End-Use Survey, Itron, March 2006. ⁹ See page 43, 44 from: California Energy Commission. 2015. *2015 Integrated Energy Policy Report*. Publication Number: CEC-100-2015-001-CMF.

⁶⁶² Navigant Consulting, Strategy and Impact Evaluation of ZNE Regulations on Gas-Fired Appliances and Phase 1 Technology Report, March 2015.

regulations, especially when they are addressed directly by other regulations that will be more impactful. For example, ARB's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, scheduled for adoption in Q1 2017, set strict emission controls and continuous ambient monitoring of natural gas facilities to prevent fugitive methane emissions.

Furthermore, SoCalGas has a long-standing commitment to reducing methane emissions from our natural gas system. SoCalGas was one of the nation's first participants in the Environmental Protection Agency's Natural Gas STAR Program in 1993. This voluntary program to control methane emissions successfully identified emission sources and mitigation methods and has resulted in significant CO₂e reductions every year since the program began. To further these gains, SoCalGas is implementing a number of best practices and new technologies, which are described in detail in our Natural Gas Leakage Abatement Report filed with the CPUC.⁶⁶³ (SOCALGAS)

Comment:

Support Current Consignment Level Increases of 5% per year – The GUG maintains that the current 5% annual increase in required allowance consignment levels for natural gas suppliers is the most prudent way forward. The most recent changes to the Cap-and-Trade Amendments propose full consignment starting in 2021. While the GUG does not object to the goal of reaching full consignment earlier than 2030, the sudden and aggressive acceleration to 100% consignment would cause substantial rate increases, which would be punitive to our customers, without delivering the reductions in emissions that ARB anticipates.⁶⁶⁴ In the supplemental material referred to as "Attachment D,"⁶⁶⁵ ARB makes several arguments for starting 100% consignment in 2021. In the following paragraphs, we attempt to summarize and address them, and demonstrate why introducing a price signal with gradual consignment, the approach used between 2015 and 2020, is more sensible and effective.

Attachment D addresses post-2020 natural gas supplier consignment requirements and offers the following four major reasons to radically accelerate the consignment to 100%: 1) it will drive conservation, 2) it will lead to equitably distributed costs, 3) it will drive

⁶⁶³ Natural Gas Leakage Abatement Report, filed by Southern California Gas Company, on June 17, 2016, in partial fulfillment of (R.) 15-01-008 to Adopt Rules and Procedures Governing Commission Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leaks Consistent with Senate Bill 1371, Leno.

https://socalgas.com/regulatory/documents/r-15-01-008/R1501008_SoCalGas%202016_Annual_Report.pdf

⁶⁶⁴ See page 3 of "Attachment D: First Notice of Public Availability of 15-Day Amendment Text. Post-2020 Natural Gas Supplier Allowance Allocation and Consignment." State of California Air Resources Board. December 21, 2016.

⁶⁶⁵ Ibid

electrification, and 4) it will result in reduced fugitive emissions. ARB's arguments are not supported by the facts as demonstrated below.

1. ARB acknowledges that higher consignment will lead to higher costs passed-through to consumers, but that this will result in less natural gas use thereby decreasing household emissions by “40 to 50 kg CO₂e” in 2021, the first year of the policy change. ARB argues that commercial and industrial sectors would reduce their emissions even more. As evidenced by well-respected energy efficiency studies and through the GUG's own observations and resource planning activities, natural gas price increases appear to have little short-term effect on consumption behavior in the retail market.^{666,667,668}

The price elasticities that ARB used to derive the emission reduction values are four to fifteen times higher than existing national, regional and state-specific studies of the natural gas short-run price elasticity.⁶⁶⁹ For comparison, the CEC Demand Analysis Office used the following price elasticities for the 2014-2024 California Energy Demand Forecast:⁶⁷⁰

Table A-6: Price Elasticities of Demand by Sector, CED 2013 Final

<u>Sector</u>	<u>Electricity</u>	<u>Natural Gas</u>
Residential	-0.08	-0.035
Commercial	-0.15	-0.15
Industrial: Manufacturing	-0.17	-0.11
Industrial: Resource Extraction and Construction	-0.10	-0.02

Source: California Energy Commission, Demand Analysis Office, 2013.

The logic behind using long-term elasticities to calculate same-year demand changes is flawed (see footnote 7 of Attachment D), leading to inflated emissions savings supposedly realized beginning in year 1 of the policy change (year 2021). ARB's analysis applied long-run elasticities to calculate short-term effects, vastly overstating

⁶⁶⁶ California Climate Change Center, *Price Impact on the Demand for Water and Energy in California Residences*, (CEC-500-2009-032-F) (2009).

⁶⁶⁷ Bernstein, M.A., Griffin, J., *Regional Differences in the Price-Elasticity of Demand for Energy*, National Renewable Energy Laboratory, (Subcontract Report NREL/SR-620-39512) (2006).

⁶⁶⁸ U.S. Energy Information Administration, *Price Elasticities for Energy Use in Buildings of the United States*. (2014).

⁶⁶⁹ The CEC/CCCC paper (footnote 3 above) noted a price elasticity value in the Pacific census division to be -0.12; the NREL paper (footnote 4 above) found California residential short-run elasticity to be -0.098; EIA study found average short-run elasticities (avg. years 1-3) for residential sector to be -0.09; and the CEC Demand Analysis Office used residential elasticity of -0.035 for the California Energy Demand 2014-2024 Final Forecast (footnote 7 below).

⁶⁷⁰ See page A-9 of California Energy Commission. *California Energy Demand 2014-2024 Final Forecast. Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency*. (CEC-20002013-004-V1CMG). 2014.

the short-run impacts. A gradual change in consignment, if known in advance, should supply the same long-run effects, without the potential for rate shock.

2. Attachment D states that accelerating full consignment will achieve equitable GHG costs between consumers and across sectors. While the GUG can understand the intent behind this thinking, in practice full consignment will likely exacerbate the disproportionate impact to residential vs. non-residential ratepayers. For example, Cap-and-Trade costs for the are imposed on all customer classes volumetrically; however, Cap-and-Trade revenues for the IOUs are returned to customers non-volumetrically through the Climate Credit, with the specific customer classes eligible to receive the Climate Credit currently being determined by the California Public Utilities Commission (“CPUC”).⁶⁷¹ Therefore, a full consignment scenario increases the cost of compliance for everyone volumetrically then redistributes the consignment proceeds to certain customers non-volumetrically, thereby creating disproportionate rate impacts.

As stated previously, the GUG is supportive of gradually reaching full consignment, but jumping to 100% over-night may place a needless and severe hardship on the state’s nonresidential ratepayers, such as small businesses, non-profits and industry, who will bear the cost burden, but will not benefit from consignment proceeds in the same way that residential customers will under a non-volumetric return of revenue regime, as proposed by the CPUC.

ARB also makes the assertion that partial consignment incentivizes fewer GHG emissions reductions from the natural gas supplied sector and leaves other sectors to accomplish those reductions. As stated in Item 1 above, increased cost pass-through resulting from full consignment will increase economic hardship on natural gas ratepayers while having little effect on short-run GHG reductions. The same long-run reductions can be achieved with a known path of consignment reductions.

3. ARB explains that full consignment is also a means to encourage fuel switching from natural gas to electricity. Increasing the costs of natural gas appliances would be harmful to customers using natural gas appliances, especially to those who do not have authority to make changes to building hot water and heating equipment, such as renting tenants. The Los Angeles County rentership rate is over 50%, the highest in the nation.⁶⁷²

Furthermore, it is far from a foregone conclusion that electric end-use appliances are lower GHG emitters than natural gas appliances in the near to mid-term. Currently, “enduse natural gas appliances most often represent a lower GHG emissions

⁶⁷¹ CPUC Decision 15-10-032 directs natural gas investor owned utilities to return consignment proceeds to residential ratepayers as an annual Climate Credit. Subsequently, the CPUC has granted a limited rehearing of the Decision in the GHG Natural Gas OIR Rulemaking 14-03-003 to discuss the California Manufacturers & Technology Association’s application for rehearing, resulting in a temporary suspension of Cap-and-Trade cost recovery and Climate Credit activity.

⁶⁷² US Census Bureau, 2012 American Community Survey.

alternative because their efficiencies are higher than power plants, avoiding energy lost in the conversion of heat (from natural gas combustion at a power plant) to electricity and back to heat. End-use natural gas appliances also avoid the major transmission and distribution losses that are inherent in the electricity system.”⁶⁷³

Moreover, moving to electric appliances presupposes that renewable natural gas (“RNG”) will never materialize. The GUG is optimistic about the role RNG will play in supporting the state’s ambitious SB 32 GHG reduction target. As key stakeholders, many GUG members have also been actively engaged in the development of the 2030 Target Scoping Plan and in advocating for actions and policies to increase RNG utilization.

In addition to the environmental benefits of near-term natural gas appliances and longterm RNG, it has been documented that consumers prefer having natural gas in their home. A recent study concluded that mixed-fuel homes have cost and consumer preference advantages over electric-only homes.⁶⁷⁴ ARB should not limit consumer choice, and should remain as technologically agnostic as possible.

4. A final argument that ARB provides for accelerating the consignment requirements to 100% in 2021 is to reduce fugitive methane emissions. ARB correctly acknowledges in Attachment D that fugitive emissions are not covered with a compliance obligation under the Cap-and-Trade Program. Therefore, since fugitive emissions are outside the scope of the Program, they should not be a foundational consideration for amending Program regulations, especially when they are addressed directly by other regulations. ARB’s Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, scheduled for adoption in Q1 2017, sets strict emission controls and continuous ambient monitoring of natural gas facilities to prevent fugitive methane emissions.

The GUG participants are committed to reducing methane emissions from their natural gas systems. For example, SoCalGas was one of the nation’s first participants in the Environmental Protection Agency’s Natural Gas STAR Program in 1993. This voluntary program to control methane emissions successfully identified emission sources and mitigation methods and has resulted in significant CO₂e reductions every year since the program began. To further these gains, SoCalGas is implementing a number of best practices and new technologies, which are described in detail in its Natural Gas Leakage Abatement Report filed with the CPUC.⁶⁷⁵ (JOINTGASUTILS)

⁶⁷³ See page 43, 44 from: California Energy Commission. 2015. *2015 Integrated Energy Policy Report*. Publication Number: CEC-100-2015-001-CMF.

⁶⁷⁴ Navigant Consulting, Strategy and Impact Evaluation of ZNE Regulations on Gas-Fired Appliances and Phase 1 Technology Report, March 2015.

⁶⁷⁵ Natural Gas Leakage Abatement Report, filed by Southern California Gas Company, on June 17, 2016, in partial fulfillment of (R.) 15-01-008 to Adopt Rules and Procedures Governing Commission Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leaks Consistent with Senate Bill 1371, Leno.

https://socalgas.com/regulatory/documents/r-15-01-008/R1501008_SoCalGas%202016_Annual_Report.pdf

Comment:

By 2020 the current regulation allows natural gas suppliers to use 50 percent of their allocated allowances to reduce the cost of compliance. Beginning in 2021, the proposed amendments would prevent natural gas suppliers from using any of their allocated allowances to reduce compliance costs. Instead, the proposed amendments would require natural gas suppliers to consign 100 percent of the allocated allowances to ARB's auctions. This is likely to produce a significant rate increase in a period of only one year. Even though the proceeds of the allowances consigned to auctions are returned to customers, it is unlikely that the amount returned will offset the rate increase that results from decreasing the amount of allowances that can be used for compliance from 50 percent to zero in a single year.

Unlike investor-owned electric distribution utilities, which have options to meet electric demand using renewable resources, natural gas suppliers have limited available natural-gas renewable resources to reliably meet the natural gas demand. Moreover, expecting customer behavior to change in response to the Cap-and Trade price signal in the three years remaining before the proposed regulation would go into effect may not be feasible. For instance, one of the options to avoid the increased cost of gas would be to replace natural gas water heating or natural gas space heating with electric equipment. It is unclear how many residential and commercial customers, including small businesses, would be able to replace (and incur the capital costs of) their natural gas heating (space and water) with electric heating in only three years to avoid the potentially significant spike in natural gas rates due to compliance with the Cap-and-Trade program.

Before adopting such changes, ARB should assess the impact of the proposed amendments on ratepayers, and should conduct market feasibility studies on the expected adoption of electrical heating equipment (water and space heating).

ORA recommends that ARB reconsider the proposed amendment that prohibits natural gas suppliers from using any of the allocated allowances for compliance beginning in 2021. ORA recommends consideration of alternative proposals, such as a previously proposed second option to gradually increase the level of consigned allocated allowances (increasing the required amount to consigned allowances by 10 percent annually, starting in 2021 to reach 100 percent by 2025). A more gradual transition to the ultimate target of requiring 100 percent of the allocated allowances to be consigned would allow incremental increases in rates without the potential for significant rate shock, and would allow more time for the market to adopt new technologies for reducing natural gas use. (OFFICERATEPAYERADVCT)

Response: The commenters request that natural gas consignment requirements increase 5% per year from 2020 through 2030, reaching 100% in 2030. ARB has adopted the requested changes as part of the second 15-day amendment package. One commenter made a similar request for gradual consignment

increases. Consignment plays an important role in the Cap-and-Trade Program for the reasons outlined in Attachment D to the First 15-Day Notice. However, in the second 15-day amendments, ARB opted to gradually increase consignment in order to avoid a sudden rate increase.

Staff wish to clarify several points disputed by commenters. The price elasticities used in Attachment D are the same values used by the California Energy Commission in the Integrated Energy Policy Report process. They are long-term elasticities because ARB is interested in the complete effect of a given policy, not only the effect which occurs during the first year of the policy.

One commenter notes that, with consignment, residential and non-residential customers are subject to similar GHG costs but receive different amounts of proceeds, since proceeds are distributed non-volumetrically. ARB agrees and notes that the Regulation requires proceeds to be distributed non-volumetrically.

Some comments mentioned that EDUs that are POUs or co-ops have no consignment requirement and this contributes to the inequity among consignment requirements which ARB is concerned about. As indicated in the ISOR, staff is considering proposing a consignment requirement for all EDUs in a future rulemaking.

One commenter requested that ARB conduct feasibility studies specifically regarding the adoption of electric water and space heating equipment. This comment is outside of the scope of this rulemaking.

Miscellaneous

B-2.2. Multiple Comments:

Maintain the Existing Cap Adjustment Factor for 2021-2030

The Cap-and-Trade Amendments continue to increase the rate of decline for Post-2020 cap adjustment factors (“CAFs”). As stated in previous comments, SoCalGas requests that ARB apply a linear continuation of the current CAFs for years 2021 through 2030. Reductions in direct allocation allowances will increase the cost pass-through while simultaneously decreasing the amount of consignable allowances that are used to mitigate costs for impacted customers and distributed as Climate Credits. The proposed CAFs are estimated to generate lower Climate Credit value than that of the current regulations, when compliance costs are at their highest (\$48 vs. \$63 per Climate Credit in year 2030).⁶⁷⁶ This mismatch between credits and costs will result in rate impacts to utility customers that can be avoided by maintaining current regulations. (SOCALGAS)

⁶⁷⁶ Values in real 2016 dollars; consignment values assume a low allowance price scenario, derived from the auction floor price in 2016 escalated by 5% a year and adjusted 2% a year for inflation. By 2030 both scenarios would have reached full consignment.

Comment:

The GUG Requests Maintaining the Existing Cap Adjustment Factor for 2021-2030

The Cap-and-Trade Amendments continue to increase the cap adjustment factor for natural gas. As stated in previous comments, the GUG requests that ARB continue to apply the same cap adjustment factor for 2021-2030 that has been applied for 2015-2020. The lower cap adjustment factor for natural gas customers is appropriate for several reasons: first, natural gas suppliers did not become regulated until 2015, and the investor owned utilities (IOUs) still have not received authorization from the California Public Utilities Commission (CPUC) to pass on their costs to customers. Second, residential natural gas customers do not have the same suite of efficiency options available to them that electric customers have, so that opportunities to reduce natural gas usage are considerably fewer in the near term for households. Finally, natural gas suppliers currently have scant opportunity to procure renewable natural gas (RNG). Providing natural gas customers the less aggressive cap adjustment factor will allow natural gas suppliers time to ramp up development and procurement opportunities in a nascent market. The cost of that market development will be reflected in retail gas rates, and a steeper increase in the cap adjustment factor would exacerbate those rate increases. (JOINTGASUTILS)

Response: The commenters request that natural gas suppliers be subject to the 2013-2020 cap decline factor of about two percent annually rather than the 2021-2030 cap decline factor of about three and a half percent per year. Please refer to the response to 45-day comment B-2.5, which answers this comment.

B-2.3. Comment:

GAS ALLOWANCE ALLOCATION – CONTINUING ALLOCATION AND MAINTAINING PLANNED CONSIGNMENT

PG&E remains concerned with the sharp increase in cost impacts to customers (including lowincome customers) from ARB staff's proposals for an accelerated CAF and accelerated consignment.⁶⁷⁷ In addition, staff's stated goal to create equity between EDUs and natural gas suppliers is premature given the few options for alternatives to natural gas, or technologies to reduce its use compared to those available in the electricity sector. PG&E recommends maintaining the existing annual decline of the cap adjustment factor (~2%), maintaining the existing annual consignment increase (5%), and increasing the ability to use offset credits for natural gas supplier compliance. These recommendations have been explained thoroughly in PG&E's previous comments and are summarized below.⁶⁷⁸

⁶⁷⁷ Attachment D: <https://www.arb.ca.gov/regact/2016/capandtrade16/attachd.pdf>

⁶⁷⁸ Pacific Gas and Electric Company. "Re: Pacific Gas and Electric Company's Comments on the Air Resources Board's Proposed Modifications to the 2016 Cap-and-Trade Amendments." Nov. 4, 2016. <https://www.arb.ca.gov/lists/com-attach/57-ct-amendments-ws-VyddPFMNUmRWDwRn.pdf>

A. Achieving the Right Balance of Carbon Costs Is Critical

The impact of the proposals to double the annual rate of decline for the CAF and sharply accelerate the consignment requirement will negatively impact customers. Staff estimates that full consignment of natural gas allowances in 2021 would result in a decrease of the average household's annual emissions by 40 to 50 kg CO₂e. ⁶⁷⁹ This equates to approximately a 2% reduction in a household's emissions compared to a 54% increase in average annual residential natural gas compliance costs in 2021 under staff's proposal. ⁶⁸⁰ This approach requires customers to pay a high price for minimal reductions. PG&E's recommendations for maintaining the current regulations are based on our support of carbon reduction approaches that customers will embrace, while maintaining affordable customer rates.

B. The Natural Gas Sector Is Fundamentally Different From the Electric Sector, and Therefore Should Be Treated Differently

Of particular concern in staff's proposal is the application of the steeper CAF for the natural gas sector. A well-designed CAF would allow the natural gas sector to reduce gas use commensurate to the CAF to maintain affordable rates for customers. However it will be very challenging to achieve the rate of reduction needed to match the steeper CAF because the natural gas sector is fundamentally different from the electric sector.

These differences include:

Different elasticities of demand

- Historically, natural gas demand from residential, small commercial and small industrial customers has not been highly responsive to retail price signals. For example, natural gas price elasticities in the near-term used by the California Energy Commission Demand Analysis Office are much lower.⁶⁸¹

Different opportunities for efficiencies

- The natural gas system is already highly efficient.
- Unlike the many end-uses for electricity, natural gas is primarily used for producing heat, for which there is a more limited range of potential efficiency gains (e.g. compared to electricity used to produce light).

Different renewables markets

⁶⁷⁹ Attachment D, p. 3: <https://www.arb.ca.gov/regact/2016/capandtrade16/attachd.pdf>

⁶⁸⁰ Pacific Gas and Electric Company. "Re: Pacific Gas and Electric Company's Comments on the Air Resources Board's Proposed Modifications to the 2016 Cap-and-Trade Amendments." Nov. 4, 2016. <https://www.arb.ca.gov/lists/com-attach/57-ct-amendments-ws-VyddPFMNUmRWDwRn.pdf>

⁶⁸¹ See page A-9 of California Energy Commission. California Energy Demand 2014-2024 Final Forecast. Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency. (CEC-20002013-004V1-CMG). 2014.

- The renewable natural gas (RNG) market is still in the early stages of development and is not yet capable of providing affordable and reliable RNG at-scale.
- Unlike solar and wind, RNG feedstock is a limited resource and is in competition with the electricity and transportation sector.
- The higher price of RNG means introducing more costs to natural gas customers, who will also face rate pressure from other sources (including GHG costs).

As PG&E has commented previously, the current differences between the natural gas and the electric sectors mean that a more gradual approach is warranted, and that other policy options to incent RNG development will be more effective to promote GHG reductions. The existing CAF, existing consignment rate and access to more offsets for natural gas would still introduce a growing price signal while allowing the natural gas sector to develop more options for alternatives and protect customers from unnecessary costs.

C. Natural Gas GHG Reduction Achievements Should be Reflected in Allocation

PG&E recommends ARB staff consider an additional allocation approach to reflect GHG reduction accomplishments in the natural gas sector. This additional allocation would account for the potential expansion of natural gas into new markets that lead to net reductions in GHG emissions, such as in the medium- and heavy-duty vehicle sectors and off-road transportation, as well as the decarbonization of the natural gas system through RNG, hydrogen, and other forms of lower carbon gas. (PG&E)

Response: The commenter requests that the natural gas supplier allowance allocations be calculated using the 2013-2020 cap decline factor, that natural gas suppliers' required allowance consignment rates increase by five percent annually during 2020-2030, that ARB increase the ability to use offset credits for natural gas supplier compliance, and that ARB allocate additional allowances to natural gas suppliers reflecting their potential expansion of supply to net GHG-reducing activities or their other GHG reductions.

Staff declines to apply a custom cap decline factor to natural gas suppliers for the reasons discussed in response to 45-day comments B-2.5 and first 15-day comments B-2.2, which focus on treating natural gas suppliers equitably with other sectors to incentivize efficiency and decarbonization. ARB has adopted 2021-2030 consignment rates for natural gas suppliers, which constitute annual five percent increases. With respect to the portion of the comment seeking to change the offset limit for natural gas suppliers or other compliance entities, that comment is outside the scope of this rulemaking, and the request would constitute treating natural gas suppliers differently from other sectors. Offsets limits are further discussed in response to 45-day comments E-1.1. Allocating

additional allowances to natural gas suppliers is also outside the scope of this rulemaking.

B-3. Legacy Contracts

B-3.1. Comment:

PEC respectfully asks ARB to amend the Regulation to continue Legacy Contract Relief for entities without an industrial counterparty as proposed by ARB staff in June 24, 2016⁶⁸². We also request that allowances not be granted to entities where a cost burden pass through does not exist. These recommended changes will ensure California's Cap and Trade Program continues to be consistent with the principles of AB 32, and will recognize that PEC has acted in good faith as a Legacy Contract holder and within the bounds of the Regulation for the past five years. Our amendments provide suggested changes to the proposed allocation methodology that are included in the 15-day package.

HISTORY

PEC is a large natural gas peaking plant with a tolling agreement ("PPA") for the exclusive sale of electric power to Pacific Gas & Electric Company ("PG&E"). The PPA was executed, prior to AB 32 in March 2006 which, in part, qualified PEC as a "Legacy Contract" PPA. Another element of PEC's "legacy contract" is that it does not include a mechanism to recover the cost of its GHG emissions. Additionally, under the PPA, PG&E controls when and how much the facility runs, and thus controls the quantity of GHG and criteria pollutant (smogforming) emissions the facility emits. At PG&E's sole discretion, the price of carbon was removed from PEC's variable energy dispatch price effective January 1, 2014 which has resulted in PEC's actual dispatch (and associated emissions) being much higher than its anticipated dispatch. This disconnect, lack of a carbon price in PEC's variable energy dispatch price, is in direct conflict with the program's foundational policies. Fundamentally, because *PEC cannot pass the costs associated with its GHG emissions along to PG&E*, those costs (the intended AB 32 "carbon price signal") are not included in PG&E's bids into CAISO for PEC's energy production ("dispatch price"). The ratepayers are not seeing the cost burden of PEC's emissions, in conflict with the Program design. Without a price of carbon included in PEC's dispatch price, the facility has operated far more, resulting in:

- (1) increasing local air pollution,
- (2) the complete undermining of the regulatory "price signal" intended to be sent to consumers,
- (3) increasing use of scarce water resources,
- (4) increasing costs for PG&E ratepayers, and

⁶⁸² <https://www.arb.ca.gov/regact/2016/capandtrade16/appf.pdf>

(5) increasing costs of operation.

Another key element of the Legacy Contract regulation is that counterparties work to resolve the Pre-AB 32 contractual issues. Since the Cap and Trade Regulation's original adoption, PEC has continually sought in good faith to secure a just and reasonable contract amendment with its counterparty *on terms consistent with other Public Utilities Commission approved Legacy Contract settlements*. PEC has repeatedly approached its counterparty to negotiate a resolution directly and through the offices of the Public Utilities Commission, ARB, private channels, and others, all to no avail. The structure of ARB's Legacy Contract Relief granted to PEC did not incentivize and may have dis-incentivized our counterparty from negotiating a settlement in good faith. Over the past five years, PEC has only sought an equitable and reasonable renegotiation of the terms of the Legacy Contract, but this has not been achieved due to our counterparty's complete lack of good-faith effort. Additionally, the proposed cessation of Legacy Contract relief would harm PEC and its bondholders, including public pension funds, and all other stakeholders (including PG&E ratepayers), except for PG&E who would continue to run PEC's facility without AB 32 compliance costs. The 15-day package proposes to continue this inequity. PEC opposes the ARB's proposed allocation to PG&E on the basis of potential and significant environmental quality impacts.

ARB has made it clear that their preferred solution is a contractual fix between the two counterparties such that going forward the cost of the program would be included in the price of the facility's electricity. But early on ARB recognized that such a fix required good faith renegotiations, and absent of this a regulatory solution was required. This is the situation we find ourselves in now. Unless ARB addresses this issue immediately within the regulatory arena, or the compliance costs are rightfully passed along to PG&E's ratepayers for the emissions created when it runs PEC's facility, this situation will continue unabated for years to come. Such a situation should undoubtedly trigger an Adaptive Management Review.

PROPOSED SOLUTION

Both Attachment A and C ignore this continuing Legacy Contract issue. We request that ARB address this issue in the next 15-day package and before this inequity is permanently codified.

ARB's proposed Electrical Distribution Utility allocation methodology is presented in Attachment C of the 15-day package⁶⁸³ with the actual allocation number provided in Attachment A (Section 95892). Attachment C states the following as fact in the background discussion:

"Electricity generators and importers face a compliance obligation for the GHG emissions associated with the energy they generate or import into California, and they

⁶⁸³ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachc.pdf>

may pass that cost on to the electrical distribution utilities (EDU) that supply the electricity to end-users.”

The first statement is not true for Legacy Contract holders, such as PEC, which is precisely why ARB included allocation provisions in prior versions of the regulation.

“In developing the Regulation, ARB recognized that allocation to EDUs should “reflect the ‘cost burden’ associated with Program emissions costs that is anticipated to be borne by the ratepayers for each distribution utility” (ARB 2010B). Cost burden is the effect on ratepayers of the incremental cost of power to serve load due to the compliance cost for GHG emissions caused by the Program.”

Whereas, the second statement has been the foundation for PEC’s policy argument for the last five years—the cost of producing the electricity should be passed along to the EDU in question, in this case that EDU is PG&E. PEC’s PPA does not contain a variable GHG emission cost component to cover the intermittent nature of its operations that coincide with a peaking power plant.

The EDU allocation numbers and methodology laid out in Attachments A and C continues the cost-burden approach. That approach is summarized in this sentence *“Cost burden would be calculated by estimating emissions for each year from 2021–2030 associated with generation from natural gas resources”*. PEC’s PPA for natural gas fired generation extends past the current 2020 EDU allocation and the plant’s operation will be directly impacted by the allocation scheme presented in this 15-day package. PG&E will be receiving allocations for PEC’s fossil fuel fired generation, but PEC will still not be able to pass along the compliance costs of the program. If the price of carbon is not associated with this generation, it will be dispatched at a higher rate than a plant of its thermal efficiency should, resulting in increased local air pollution. This increase in criteria and toxic pollutants will occur in an area identified as disadvantaged by the State.⁶⁸⁴ ARB staff presented a workable solution to address this situation, in the public workshop preceding the August 2, 2016 release of the regulatory package. This solution proposes to treat the few remaining Legacy Contract holders without an industrial counterparty the same as other non-power plant Legacy Contract holders.⁶⁸⁵ The subsequently published proposed amendments failed to include that staff’s recommended solution (without opportunity for public input), and now proposes to completely eliminate “Legacy Contract” status and regulatory relief for the remaining entities such as PEC. This 15-day Amendment Package continues this inequity and exacerbates the policy problem facing ARB. PEC’s costs are being calculated in PG&E’s ‘cost-burden’ without PG&E actually having those costs. If adopted without change, the current draft amendments would leave the PEC facility completely exposed

⁶⁸⁴ <http://oehha.ca.gov/calenviroscreen/report/calenviroscreen-version-20>

⁶⁸⁵ Staff’s presentation at the June 24, 2016, workshop (slide 35)

https://www.arb.ca.gov/cc/capandtrade/meetings/062416/arb_and_caiso_staff_presentations_updated.pdf, is included in Appendix F to the Initial Statement of Reasons – <https://www.arb.ca.gov/regact/2016/capandtrade16/appf.pdf>.

to the price of AB 32 compliance, stranding those costs with PEC, and would continue the ongoing environmental and economic consequences described above.

There is still an opportunity for ARB to correct this situation, and a way to move forward with a specifically tailored, holistic solution. In light of the unsuccessfully Legacy Contract renegotiations, PEC requests that ARB amend the regulatory language to include the June 24, 2016, staff workshop proposal in a future 15-day amendment package⁶⁸⁶.

In addition to PG&E receiving allocations for the emissions associated with PEC's facility without a cost-pass through obligation, ARB erred in its assignment to PG&E for having Natural Gas cost burden associated with the replacement of Diablo Canyon's zero GHG electricity. PG&E has committed to the following⁶⁸⁷:

"Pacific Gas & Electric (PG&E), International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, Friends of the Earth, Natural Resources Defense Council, Environment California, and Alliance for Nuclear Responsibility (together, the parties) have developed a joint proposal to retire PG&E's Diablo Canyon Power Plant at the close of its current operating license period and replace it with a portfolio of greenhouse gas (GHG)-free resources."

This commitment should be applauded, but it should not entitle PG&E to an additional and very large set of allowance allocation. ARB's allocation methodology comparison, starting on page 4 in Attachment C clearly states "The proposed method accounts for retirements of coal plants and the Diablo Canyon nuclear facility by assuming that these facilities are replaced by natural gas-powered electricity after they retire." *This assumption is not accurate and further reflects PG&E obtaining significant allowances without the accompanying cost burden— 4,925,396 tons worth.* PEC is opposed to this allocation as unwarranted and inconsistent with the cost-burden approach used for other electrical allocations.

There are no legal impediments that prevent ARB from implementing PEC's request. Because the staff proposal was included in the Initial Statement of Reasons for the proposed amendments, modifying the proposed amendment to include staff's proposal in a future 15-day package complies with law. Likewise, the recent Court of Appeal decision in litigation between PG&E and PEC and the earlier arbitration award, both acknowledge the limited contractual scope of that dispute, and explicitly state that nothing written in those decisions in any way limits ARB's power to resolve the issue of PEC's stranded costs in order that the PEC facility be run consistent with CARB policy to protect the environment and the public.

The prior regulatory relief, set to be eliminated, and the current proposed amendments (failing to address PEC's issue and providing unwarranted allocations to PG&E)

⁶⁸⁶ Numerous references to a second 15-day amendment package in Attachment A:
<https://www.arb.ca.gov/regact/2016/capandtrade16/attacha.pdf>

⁶⁸⁷ https://www.pge.com/includes/docs/pdfs/safety/dcpp/MJBA_Report.pdf

provided no incentive for PG&E to address this situation, while the environment, the citizens of the San Joaquin Valley (a disadvantaged community), PG&E's ratepayers, and PEC's bondholders are would be negatively affected. There are no winners under the current proposal, only losers.

To avoid these impacts, and for the reasons described in this letter, ARB should not adopt the amendments as proposed, but instead should either incorporate the June 24, 2016, staff workshop proposal constructed specifically to address the problem outlined below or take other actions to ensure the fundamental policies of the program are upheld without undue burden on Legacy Contract holders.

PEC urges ARB to act now. We have actively engaged at all levels of the ARB process and sought in good faith to find a solution for the better part of five years, now it is up to ARB to step in and fix this problem before additional local pollution is emitted as a direct result of its implementation. With at least one future 15-day amendment package remaining, ARB still has a chance to bring this conclusion. (PANOCHE)

Response: The commenter requests amendments to the legacy contract transition assistance for generators without industrial counterparties as staff proposed at its staff workshop on June 24, 2016, and that "allowances not be granted to entities where a cost burden pass through does not exist." Staff notes that the workshop proposal was not included in the formal regulatory amendments package, and insofar as staff are able to interpret what is meant by the latter request, it appears to be outside the scope of the current rulemaking. Therefore, the requested change is outside the scope of the current rulemaking.

B-3.2. Comment:

On behalf of Crockett Cogeneration ("Crockett"), I submit the following comments on the California Air Resources Board's proposed amendments to the Cap-and-Trade Regulation, as well as suggested modifications to the text of the amendments as proposed. An earlier version of these comments was submitted to the Board on behalf of Crockett on November 4, 2016 for consideration and inclusion in the record for the proposed amendments to the Cap-and-Trade Regulation.⁶⁸⁹ Crockett subsequently presented its views at the Board's November 17, 2016 meeting, where the Board directed Staff to evaluate options for considering Crockett's comments.⁶⁹⁰ These

⁶⁸⁸ Submitted at:

https://arb.ca.gov/lispub/comm/bcsubform.php?listname=capandtrade16&comm_period=1.

⁶⁸⁹ These comments were also submitted for consideration following the Cap-and-Trade Program Workshop held on October 21, 2016. See Comments of Crockett Cogeneration (Nov. 4, 2016), [https://www.arb.ca.gov/lispub/comm2/bccomdisp.php?listname=ct-amendments-
ws&comment_num=21&virt_num=20](https://www.arb.ca.gov/lispub/comm2/bccomdisp.php?listname=ct-amendments-ws&comment_num=21&virt_num=20). They are also now included in the record within Attachment E: Public Workshop Materials, as part of the Board's December 21, 2016 Notice of Availability of Modified Text and Availability of Documents and/or Information. See Attachment E, at 155-157, <https://www.arb.ca.gov/regact/2016/capandtrade16/attache.pdf>.

⁶⁹⁰ Transcript of Meeting of the State of California Air Resources Board, at 334-337 (Nov. 17, 2016), <https://www.arb.ca.gov/board/mt/2016/mt111716.pdf>.

comments and proposed textual modifications are submitted today in connection with the Board's November 17 directions...

Background: Legacy Contracts and the Proposed Amendments

When the Cap-and-Trade Regulation was initially implemented, the Board provided allowances to investor owned utilities ("IOUs") and various other covered entities, subject to a declining cap. It became apparent that some "legacy contracts" (now defined in 17 CCR § 95802(a)(204)) were not covered by the Board's original allocation of allowances, and that there were inequities with regard to legacy contract treatment. Legacy contract holders appeared before the Board to plead their case, and the Board directed Staff to consider and act upon these concerns. Accordingly, Staff proposed in 2013 and the Board in 2014 adopted provisions to assist legacy contract holders.

Legacy contract holders with IOUs or industrial counterparties lent themselves to a solution in which allowances were transferred from one party to another. However, for legacy contracts without an industrial counterparty – with several diverse and unique examples – it became necessary to allocate allowances based on previous emissions. The Board chose 2012 as that reference year. The Board also conditioned assistance on proof that the legacy contract holders continue to try to negotiate with their counterparties to absorb the cost of allowances. In some cases this proved possible, in other cases it continues to prove impossible.

In 2014, the Board decided that for legacy contracts with an industrial counterparty, transition assistance would be provided for the life of the contract. 17 CCR § 95870(g)(2). However, for those without an industrial counterparty, the Board limited transition assistance to the end of the second compliance period *Id.* § 95870(g)(1). At the time of its decision, the Board understood that there was only one legacy contract without an industrial counterparty that extended beyond 2017 – Crockett – whose contract extends until 2026. The Board urged Crockett to continue to negotiate with its counterparty, C&H Sugar, and to return to the Board later if it could not do so.⁶⁹¹ No promises were made to extend the transition assistance period, but the door remained open for conversation.

On August 2, 2016, the Board issued its Notice of Public Hearing to consider proposed amendments to the Cap-and-Trade Regulation. On December 21, 2016, it subsequently issued a Notice of Availability of Modified Text and Availability of Documents and/or Information. Among the amendments as currently drafted, Staff proposes to delete provisions pertaining to transition assistance for legacy contract generators without an industrial counterparty. For the reasons detailed below, Crockett proposes that the relevant provisions be retained and modified to extend assistance for the life of the contract.

⁶⁹¹ C&H Sugar is not considered an industrial counterparty because it does not have sufficient emissions to be subject to reporting under the MRR or to the Cap-and-Trade Regulation.

Basis for Extension of Relief

Crockett is equitably as entitled to transition assistance as any other legacy contract generator that is provided that assistance for the life of its contract. Crockett provides steam (heat) to C&H Sugar. C&H Sugar uses the steam provided by Crockett to first produce all the electrical energy required for operation of the refinery and second to supply all the thermal processes required to refine the sugar and produce its products. The steam sales contract does not provide for any pass-through for the type of costs created by the Cap-and-Trade Regulation. C&H, were it to have emissions of its own, would readily qualify as an energy-intensive trade-exposed (“EITE”) industrial entity covered under the Regulation. It is the only cane sugar refiner west of the Mississippi, and competes nationally and internationally based on price. As a result, C&H has been unwilling to shoulder any of the load of compliance costs, including the cost of joining the system and reporting.

Given Crockett’s continued inability to re-negotiate its contract with its counterparty, we ask for the Board’s consideration of the fairness of extending transition assistance for the life of Crockett’s contract (2026), subject to all of the same conditions that have been heretofore required for such assistance. Consistent with this letter, Crockett respectfully requests that Staff incorporate the changes included in Exhibit A to the amendments as currently proposed.

EXHIBIT A

Recommended Modifications

Section 95802(a)(206). As proposed by Staff, the language relating to generators without an industrial counterparty would be deleted. Crockett proposes that the existing definition be retained in full, as is, with Staff’s proposed deletions retained ([] underline):

“Legacy Contract Emissions” means the covered emissions calculated, based on a positive or qualified positive emissions data verification statement issued pursuant to MRR, by the legacy contract generator with an industrial counterparty, or from a legacy contract generator without an industrial counterparty, that are a result of either electricity and/or legacy contract qualified thermal output sold to a legacy contract counterparty, and calculated pursuant to section 95894 of this regulation.

Section 95802(a)(208). As proposed by Staff, this provision would be deleted entirely. Crockett proposes that it instead be retained entirely:

Legacy Contract Generator without an Industrial Counterparty” means a covered entity that generates and sells electricity, thermal energy, or both, subject to a legacy contract, and does not also sell electricity or thermal energy under the legacy contract to a covered entity eligible for allowance allocation pursuant to section 95891.

Section 95870(g)(1). Staff proposed to delete Section 95870(g)(1) in full. Crockett proposes that this provision be retained in full, with the following modifications:

Allowances will be allocated to legacy contract generators without an industrial counterparty for ~~budget years 2013 through 2017 for transition assistance~~ pursuant to section 95894 for the term of the contract. The Executive Officer will transfer allowance allocations into each eligible generator's annual allocation holding account by October 24 of each calendar year for eligible legacy contract emissions pursuant to the methodology set forth in section 95894 ~~each year through 2017.~~

Alternatively, Staff could identify parties "without an industrial counterparty" in current Section 95870(g)(2), as (g)(1) and (g)(2) would be largely duplicative under Crockett's proposal.

New Section 95871(f). Staff proposes to add this provision to address allocation to legacy contract generators post-2020. Crockett proposes the following amendment to capture generators without an industrial counterparty:

Allocation to Legacy Contract Generators. Allowances will be allocated to legacy contract generators with an industrial counterparty and without an industrial counterparty pursuant to section 95894 for the term of the contract. The Executive Officer will transfer allowance allocations into each eligible generator's annual allocation holding account by October 24 of each calendar year during the term of the contract for eligible legacy contract emissions pursuant to the methodology set forth in section 95894 beginning in 2020 for allocation from the 2021 annual allowance budget.

Section 95890(e). As proposed by Staff, the language relating to generators without an industrial counterparty would be deleted. Crockett proposes that Staff's proposed deletions be retained ([] underline):

Eligibility Requirements for Legacy Contract Generators. A legacy contract generator with an industrial counterparty that has demonstrated its eligibility to the satisfaction of the Executive Officer pursuant to section 95894 of this regulation shall be eligible for direct allocation of allowances if it has complied with the requirements of MRR and has obtained a positive or a qualified positive emissions data verification statement pursuant to MRR. A legacy contract generator without an industrial counterparty that has demonstrated its eligibility to the satisfaction of the Executive Officer pursuant to section 95894 of this regulation shall be eligible for direct allocation of allowances if it has complied with the requirements of MRR and has obtained a positive or a qualified positive emissions data verification statement pursuant to MRR.

Section 95894(a). As proposed by Staff, the language relating to generators without an industrial counterparty would be deleted. Crockett proposes that language be retained ([] underline), rather than deleted, from the excerpted portion of Section 95894(a), below:

Demonstration of Eligibility. Opt-in covered entities are not eligible for transition assistance due to legacy contract emissions. To be eligible to receive a direct allocation of allowances under this section, the primary or alternate account representative of a

legacy contract generator with an industrial counterparty or legacy contract generator without an industrial counterparty shall submit the following in writing via certified mail to the Executive Officer by...

Section 95894(a)(1)(A)-(B). As proposed by Staff, these provisions would be modified to delete Section 95894(a)(1)(B). Because this section is relevant to the allocation methodology for generators without an industrial counterparty under Section 95894(d), Crockett proposes that the following language be retained ([] underline) rather than deleted as proposed by Staff:

(A) Previous data year's legacy contract emissions, pursuant to section 95894(c); and

(B) 2012 data year's legacy contract emissions, pursuant to section 95894(d)

Section 95894(a)(3)(C). As proposed by Staff, the language relating to generators without an industrial counterparty would be deleted. Crockett proposes that language be retained ([] underline), rather than deleted, from the excerpted portion of Section 95894(a)(3)(C), below:

The operator of the legacy contract generator with an industrial counterparty or the legacy contract generator without an industrial counterparty made a good faith effort...

Section 95894(b). As proposed by Staff, the reference to Section 95894(d) would be deleted. This provision relates to allocations for generators without an industrial counterparty. Crockett proposes that this reference be retained.

Section 95894(d). As proposed by Staff, Section 95894(d) would be deleted entirely. Crockett proposes that relevant portions be retained and modified to extend assistance for the life of the contract. Specifically, Crockett proposes that Section 95894(d) be retained and modified as follows:

(d) Allocation to Legacy Contract Generators without an Industrial Counterparty. For legacy contracts not covered in 95894(c), the following ~~formulae~~ equation shall apply:

(1) For stand-alone generation facilities that are legacy contract generators without an industrial counterparty:

$$TrueUp_{2015} = (EE_{mlc} * c_{2013}) + (EE_{mlc} * c_{2014}) + (EE_{mlc} * c_{2015})$$

Where:

"TrueUp₂₀₁₅" is the amount of true up allowances allocated from budget year 2015 and allowed to be used for compliance for budget years 2013 and 2014 and subsequent years, pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"EE_{mlc}," is the emissions reported, in MTCO_{2e}, associated with electricity sold under the legacy contract in 2012; and

“c₂₀₁₃,” “c₂₀₁₄,” and “c₂₀₁₅,” are the cap adjustment factors for budget years 2013, 2014, and 2015, respectively, as specified under the “Cap Adjustment Factor (c) for All Other Direct Allocation” column in Table 9-2.

For budget years 2016 and 2017 the following equation applies:

$$A_t = (EE_{mlc} * c_t)$$

Where:

“A_t” is the amount of California GHG allowances directly allocated to the legacy contract generator without an industrial counterparty for legacy contract emissions from budget year “t.” This value shall only be calculated if the entity meets the eligibility requirements, pursuant to section 95894(a) and 95894(b), and is covered under the Cap-and-Trade Program during the second compliance period.

EE_{mlc},” is the emissions reported, in MTCO_{2e}, associated with electricity sold under the legacy contract in 2012; and

“c_t” is the adjustment factor for budget year “t,” as specified under the “Cap Adjustment Factor (c) for All Other Direct Allocation” column in Table 9-2.

(2) For legacy contract generators without an industrial counterparty not covered in 95894(c) or 95894(d)(1):

$$TrueUp_{2015} = ((Q_{lc} * B_s + E_{lc} * B_e) * c_{2013}) + ((Q_{lc} * B_s + E_{lc} * B_e) * c_{2014}) + ((Q_{lc} * B_s + E_{lc} * B_e) * c_{2015})$$

Where:

“TrueUp₂₀₁₅” is the amount of true-up allowances allocated from budget year 2015 and allowed to be used for compliance for budget years 2013 and 2014 and subsequent years pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

“Q_{lc},” is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in data year 2012, as reported to MRR;

“E_{lc}” is the electricity, in MWh, sold under the legacy contract in data year 2012;

“B_e” is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

“B_s” is the emissions efficiency benchmark per unit of legacy contract qualified thermal output,

0.06244 California GHG Allowances/MMBtu thermal; and

“c₂₀₁₃,” “c₂₀₁₄,” and “c₂₀₁₅” are the cap adjustment factors for budget years 2013, 2014, and 2015, respectively, as specified under the “Cap Adjustment Factor (c) for All Other Direct Allocation” column in table 9- 2.

For budget years 2016 and 2017, the following equation applies:

$$A_t = ((Q_{lc} * B_s + E_{lc} * B_e) * c_t)$$

Where:

“ A_t ” is the amount of California GHG allowances directly allocated to the legacy contract generator without an industrial counterparty, for legacy contract emissions from budget year “ t .” This value shall only be calculated if the entity meets the eligibility requirements, pursuant to section 95894(a) and 95894(b), and is covered under the Cap-and-Trade Program during ~~the second compliance period~~ budget year “ t ”;

“ Q_{lc} ,” is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in data year 2012, as reported to MRR;

“ E_{lc} ” is the electricity, in MWh, sold under the legacy contract in data year 2012;

“ B_e ” is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

“ B_s ” is the emissions efficiency benchmark per unit of legacy contract qualified thermal output,

0.06244 California GHG Allowances/MMBtu thermal; and

“ c_t ” is the cap adjustment factor for budget year “ t ” as specified under the “Cap Adjustment Factor (c) for All Other Direct Allocation” column in ~~Table~~ Table 9-2.

Section 95894(e). As proposed by Staff, the language relating to generators without an industrial counterparty would be deleted, and the Section would be re-lettered as “(d)” to account for Staff’s proposed deletion of Section 95894(d) in full. Crockett proposes that Staff’s proposed deletions be retained ([] underline):

Data Sources. In determining the appropriate values for section 95894(c) and 95894(d), the Executive Officer may employ all available data reported to ARB under MRR and all other relevant data, including invoices, that demonstrate the amount of electricity and legacy contract qualified thermal output sold or provided for off-site use does not include a carbon cost in the budget year for which it is seeking an allocation. If necessary, the Executive Officer will solicit additional data to establish a representative allocation. The operator of the legacy contract generator with an industrial counterparty and the operator of a legacy contract generator without an industrial counterparty, must provide the additional data upon request by the Executive Officer.

Section 95894(f). As proposed by Staff, the language relating to generators without an industrial counterparty would be deleted, and the Section would be re-lettered as “(e)” to account for Staff’s proposed deletion of Section 95894(d) in full. Crockett proposes that Staff’s proposed deletions be retained ([] underline):

Contract Expiration or Generator Closure. Once a legacy contract expires or the legacy contract generator with an industrial counterparty or legacy contract generator without an industrial counterparty closes operations, the generator will no longer be eligible for free allocation pursuant to 95890(e), and allocation will be prorated for the time in which the contract was eligible. (CROCKETTCOGEN)

Response: The comments request regulatory amendments to continue legacy contract transition assistance to generators without industrial counterparties. Prior to these amendments, the regulation included provisions for legacy contract generators without industrial counterparties to receive transition assistance through vintage year 2017. In this rulemaking, those provisions were removed because they are moot after 2017, not because ARB staff proposed any substantive revision to such provisions. The ISOR and Notice for this rulemaking set forth the scope of this modification, and staff believes this scope does not include the ability to extend legacy contract allocation beyond 2017 as part of this rulemaking. As such, the requested changes are outside the scope of this rulemaking.

B-4. University Covered Entities

B-4.1. Comment:

The University of California (the "University") supports the California Air Resources Board's ("CARB") staff proposal to continue to provide transition assistance through the annual allocation of allowances to universities and public sector entities ("UPSEs"). Nevertheless, the University requests two modifications to its annual allocation to account for a change in ownership of the combined heat and power ("CHP") facility located at the Berkeley campus. First, the University respectfully requests that CARB increase the Berkeley campus's baseline emissions for the purposes of calculating annual allocations in recognition of the increased emissions from the campus's assumption of ownership of the CHP facility. Second, if CARB is unable for the next few years to provide annual allocations equal to the Berkeley campus's revised baseline emissions after transfer of the CHP facility, the University asks that CARB provide in 2021 a true-up allocation for the additional allowances that CARB would otherwise have granted to the Berkeley campus during the years 2018-2020.

Under the proposal put forth by CARB, UPSEs would continue to receive an allocation based on an established baseline multiplied by the annual cap adjustment factor. The University views this as an appropriate solution, that balances monetary incentives to reduce emissions, while allowing for funds to be redirected toward greenhouse gas reduction efforts. In 2016, this provision saved the University almost \$9 million, which allowed it to spend the funds on projects that are reducing greenhouse gas emissions across the University's ten campuses.

Continuing under a business-as-usual scenario, however, does not address the changing needs of the Berkeley campus. Currently, the CHP facility located on the

campus is owned by a third-party, which sells steam to the campus and electricity to the local utility. The Berkeley campus is an opt-in entity under the cap-and-trade regulations, and it receives allowances from CARB under the provisions for UPSEs. The campus currently passes the majority of the allowances associated with the purchased steam through to the current owner of the CHP, while using the remaining allowances to meet the campus's compliance obligations. In 2017, the CHP contract with the third-party ends, as does the contract the third-party has to sell the electricity to the local utility. The ending of both of these contractual arrangements requires the campus to assume ownership of the CHP and use the electric output to meet its own load requirements.

One result of the change of ownership is that the campus would be responsible for the increased emissions and for meeting compliance instrument obligations under the cap-and-trade regulations. At current allowance prices, the University estimates that the annual fee just for the complying with the increased emissions from the electrical portion of CHP facility would surpass \$1 million. This money could be spent on greenhouse gas reduction projects instead, as happens at other UPSEs that operate such CHP facilities. Due to this serious financial impact, the University thus requests that CARB increase its allocation to the Berkeley campus to match the treatment of other universities and public sector entities. With the change in ownership of the CHP, there will be no net increase or decrease in statewide CO₂ emissions. CARB can reallocate the allowances from the local utility to the University since the utility will no longer purchase electricity from this facility and the cost of emissions will not be a burden on its ratepayers. Without a change in the campus's baseline emissions for annual allocation to reflect the assumption of ownership and operation of the CHP facility, the University's cost will be borne by students and will inhibit further greenhouse gas reduction investments.

Another concern is that the Berkeley campus would be under-allocated allowances for the third compliance period (2018-2020). It is the University's understanding that changes to allocations in the third compliance period are out of the scope for the current revisions of the regulations and that CARB may not be able to provide annual allowances at the University's new baseline for the 2018-2020 period. To address this problem the University respectfully requests that CARB retroactively allocate these needed allowances through a true-up allocation 2021, similar to the true-up allocation for UPSEs in 2015. The University estimates the additional cost related to cap-and-trade obligations for the third compliance period to be \$3-\$5 million. (UNIVCALIF)

Response: UC Berkeley requests that their baseline allocation value be recalculated for university allocation if they purchase the adjacent CHP facility. Section 95891(d)(2) of the Regulation regarding data sources for determining allocation to university covered entities specifies that the Executive Officer may employ all available data reported to ARB under MRR for data years 2008 through 2013, and staff is able to utilize data from both the UC Berkeley and adjacent CHP facility for those years. However, staff notes that baseline

allocation values are calculated based on total fuel consumed multiplied by the natural gas benchmark and adjusted to include emissions from steam purchases and exclude emissions from steam and electricity sales. Pursuant to this language, staff must exclude the electricity sold to the local utility during the 2008 through 2013 period. The university baseline allocation value section of the Regulation is out of scope for the Proposed Amendments. Staff welcomes further discussion with UC Berkeley on how this issue might be addressed in a future rulemaking.

B-5. Industrial Allocation

Benchmarks

B-5.1. Multiple Comments:

[W]e continue to emphasize additional concerns regarding benchmarks raised in previous comments.

Benchmarks

In the 45-day regulatory proposal, staff proposed eliminating the benchmark for tree nut manufacturing because emissions per unit of product are highly variable. In absence of a benchmark, staff suggested that covered entities conducting this activity would receive allowance allocations under the energy-based methodology. In joint comments by Ag Council and the Agricultural Energy Consumers Association on September 19, 2016, we recommended, “reinstating the benchmark for tree nut manufacturing and refining the product-based benchmark to reflect updated data and efficiency trends.”⁶⁹² In the Modified Regulation staff expresses that the benchmark review is ongoing and staff may propose further changes. We are committed to keeping the Almond Processing and Pistachio Processing Benchmark intact. We hope to find a resolution that works for both ARB and covered entities. (AGCOUNCIL)

Comment:

1. Roasted Nuts and Peanut Butter Manufacturing (NAICS 311911) Should Remain Under the Product-Based Benchmarking Category

ARB has tentatively proposed to eliminate tree nut manufacturing from the product-based benchmarking category. Instead, manufacturers in this NAICS code will be subject to energy-based benchmarking. In the *Initial Statement of Reasons*, ARB is proposing to change the product-based benchmark for this category based on the following reasons: (1) emissions in these sectors are highly variable making it challenging to accurately predict the energy required to roast nuts; and (2) there are no longer any covered entities conducting activities that fall within this category. We are opposed to the elimination of product-based benchmarking for tree nuts because ARB

⁶⁹² <https://www.arb.ca.gov/lists/com-attach/73-capandtrade16-UTIGYVEgVSsKbQNt.pdf> (page 7)

has failed to provide valid legal or factual rationale for doing so. Therefore, we request that the product-based benchmark for tree nuts be retained. If ARB needs additional technical information to further refine the previously approved benchmarks, WPA is committed to providing ARB that information.

As a fundamental issue, it is inappropriate for ARB to completely eliminate the product-based benchmarks that WPA spent over a year developing in collaboration with ARB, and that were adopted in 2014. Regulated entities need regulatory certainty. It is unfair for ARB to propose such a significant change to its approach a mere two years after it initially adopted the product-based benchmarks.

A. WPA Will Be Back in the Cap-and-Trade Program for 2016

In terms of ARB's factual rationale, while it is true that there are no covered entities currently subject to the Cap-and-Trade Program utilizing the product-based benchmark for roasted nuts, the 2016 crop will put WPA back in the Cap-and-Trade Program. The pistachio crop, like many other agricultural commodities that are impacted by weather, is variable. Last year, the industry produced 275 M lbs, while this year the estimated volume is a record 750-800 M lbs. To date, WPA has already processed 300 M lbs of pistachios at the same Lost Hills facility that was previously covered by the Cap-and-Trade Program. Greenhouse gas (GHG) emissions for nut processing facilities are closely correlated with pistachio and almond harvest volumes, which are directly influenced by climate, a factor outside of WPA's control. Due to extended drought conditions and other weather related issues, including insufficient chilling hours during the winter, 2013, 2014, and 2015 harvest volumes were down, and consequently GHG emissions at the WPA Lost Hills facility stayed below the Cap-and-Trade Program applicability threshold. But, based on a record harvest for 2016, WPA will be back in the Program next year, so elimination on the basis that there are no longer covered entities is not factually justified.

B. Variability of Emissions and Moisture Content is Inherent in Nut Processing and Previously Acknowledged by ARB

With regard to the variability in emissions, like many other agricultural products, the climatic and soil condition under which pistachios and almonds are grown, largely influence the moisture content of these products. As the climate and soil conditions change year to year, the moisture content of the product changes variability of moisture content of the raw pistachios and almonds is an inherent characteristic of tree nuts, which has always existed. During the 2013 rulemaking process, ARB was provided with a great deal of information regarding the harvest production, storage, treatment processes, and fuel consumption related to the processing of pistachios and almonds, and this information was used by ARB to develop the appropriate product-based benchmarks for pistachios and almonds, respectively. The harvest methodology and the inherent variability of moisture content in WPA's raw pistachios and almonds did not change since the 2013 rulemaking. It is therefore neither appropriate nor fair for ARB to

propose elimination of the 311911 NAICS code benchmarks because the water content of raw nuts varies year-to-year...

2. If Necessary, ARB Should Refine the Product-Based Benchmark, Rather Than Eliminate It

ARB asserts that product-based benchmarking is the preferred approach in order to minimize leakage. However, ARB's proposal to eliminate product-based benchmarks for pistachio and almond products is inconsistent with that approach and the intent of AB 32. As such, we strongly recommend that ARB consider refining the product-based benchmarks for pistachios and almonds, as opposed to elimination of the category. Such an approach is similar to ARB's proposal with respect to calcium ammonium nitrate solution and nitric acid production (NAICS code 325311), where emissions are also highly variable. Wonderful recommends that ARB bear in mind the following when considering the product-based benchmark calculation for this category:

- The initial benchmarks were derived using 2010 and 2011 data. The product-based benchmarks should be updated using data years 2010-2015 because: (1) ARB has Mandatory Reporting Regulation data to ensure the rigorousness of the data quality (2010 through 2015 data are verified); and (2) efficiency tends to improve over time, such that using these data years for nut products ensures that efficiency improvements are taken into account in an equitable manner.
- Because WPA is the only covered entity under the Cap-and-Trade program, apply ARB's benchmark stringency with "90% of Average" or "Best-in-Class" value, using the 2010-2015 data from WPA.

If ARB requires additional information to further refine the product-based benchmark for roasted nuts, including developing refined benchmarks for each process, WPA would be happy to work with ARB staff to provide that information. (WONDERFUL)

Response: Please refer to the response for 45-day comment B-5.4, which answers this comment.

B-5.2. Comment:

We are also requesting that our use of recycled glass, sourced from California, be retained as an early action credit and part of any changes to the industries emissions benchmark.

California Glass Container Manufacturing Company Capital and Environmental Investments:

The three California glass container manufacturing companies have made sizable investments to improve the efficiency of their plants, and to reduce greenhouse gas emissions. The California glass container manufacturing industry investments were made well in advance of Cap and Trade program regulations.

Since 1993, California glass container manufacturing companies have invested \$101.1 million directly into efficiency of their glass container plants (\$66.3 million of this investment since 2006), thereby reducing associated GHG emissions levels.

Specific investments have been made in the following equipment and technology include at multiple California glass container manufacturing plants:

- Converted furnaces to oxygen or “oxy-fueled” – reducing the levels of nitrogen oxide, fuel consumption and associated greenhouse gas emissions.
- To further improve efficiencies, oxygen plants have also been installed. In glass container manufacturing furnaces, this permits oxygen to be more effectively used to reduce energy needed to reach optimum melting temperatures, and improve the overall melting process.
- Updated and installed Continuous Emissions Monitoring Systems (CEMS) at the plants, as well as replacing and upgrading flow monitoring equipment.
- Scrubber and EP Systems have been updated and installed to reduce air emissions.
- Installed additional recycled glass bunkers and silos, in order to accommodate hundreds of thousands of tons of recycled glass annually.
- Replaced furnace burners to improve energy efficiency.
- Upgraded furnaces designs to improve energy efficiency.
- Installed predictive controls on furnaces to improve energy efficiency.

These investments in energy efficiency improvements do not include an additional \$105 million California glass container manufacturing companies have spent over the past decade to keep plants operational.

Credits for Early Action Need to be Maintained:

In addition to the efficiency investment described, California glass container manufacturing companies have purchased substantial recycled glass, for use in the manufacture of new bottles and jars. The use of recycled glass in the production of new glass containers reduces energy (2-3% for every 10% of recycled glass and associated greenhouse gas emissions (4-8% for every 10% of recycled glass).

This is an important issue for the GPI companies. The glass container manufacturing industry purchases large amounts of recycled glass processed in the state and the industry benchmark should continue to recognize this point.

Maintaining early action credit and a high industry assistance factor does not eliminate the cost of compliance for GPI members, and by extension the market signal to reduce GHG emissions. Purchasing California recycled glass is costly. In fact, recycled glass

sourced in the state is often at a 30% higher cost than recycled glass in neighboring jurisdictions.

Since 2014, the glass container manufacturing industry has purchased roughly 1.5 million tons of recycled glass for reuse in California glass container plants, at an estimated cost of \$135 million. This effort, along with the installation of energy efficiency based equipment and technology, has helped reduce overall GHG emissions levels in California glass container plants by 4% from 2014 to 2016.

The attached chart demonstrates that glass container manufacturers increased the use of cullet prior to the current cap-and-trade program implementation. Preserving the early action credit only helps to advance the state's recycling and emissions reduction goals.

Nonetheless, the benchmark was intended to provide early action credit to our industry consistent with the requirements in AB 32. Early action credit helps manufacturing facilities operating in the state to compete with out of state manufacturers which either have not taken early action or do not operate under a similar program. And therefore, producing similar products without the burden of additional cost. These circumstances have not changed, and eliminating early action credit would simply increase the trade exposure and risk of leakage. (GLASS PACKAGING)

Response: The commenter requested that ARB maintain credit for early action in the container glass benchmark. Benchmarks for industry allocation are set using representative years of operation; in cases where it is appropriate to set those representative years to recognize early action for GHG reductions, staff has done so. Benchmark amendments for post-2020 allocation will occur in a subsequent rulemaking process which will involve public meetings and stakeholder engagements.

Miscellaneous

B-5.3. Comment:

Section 95891 and Table 9- 2 - Cap Adjustment Factors

The cap adjustment factors proposed for certain industries with 50 percent or more process emissions and high trade exposure (e.g., nitric acid production, cement, etc.) should also be applied to coke calcining. This sector fits a similar process profile. As noted in February 27th, 2013 BP 's letter to ARB (provided directly to staff for business confidentiality reasons), approximately 95% of calciner's emissions are process emissions. (TESORO)

Response: The commenter requests to have coke calcining added to the sectors with a reduced decline in the cap adjustment factor. For the 2013-2020 cap adjustment factors, this comment is outside the scope of the Proposed Amendments. Potential alternate cap adjustment factors during the post-2020

period are premature until a post-2020 allocation methodology has been established in a subsequent rulemaking.

B-5.4. Comment:

3. Covered Entities Should Not Be Required to Pay Back Allocation Allowances Immediately

ARB has proposed to modify provisions related to the return of allowances by entities that were allocated free allowances and subsequently did not incur a compliance obligation or applied to exit the Cap-and-Trade Program. We acknowledge that the proposed changes are set to take effect for budget year 2018 and forward, but believe this is a critical issue, especially for entities in the agricultural sector that have variable GHG emissions, and therefore could come in and out of the Cap-and-Trade Program.

We recognize that ARB is proposing to apply this new retirement provision only to entities with energy-based benchmarks, but we cannot support ARB employing this method in any case where an entity's operations are not year round and highly variable year over year. This proposed amendment is particularly troubling for covered entities in the agricultural sector where seasonality, light and alternating crops (such is the case with tree nuts), and forces outside of the manufacturers control (i.e., drought and other climate conditions) impact whether an entity remains a covered entity under the Cap-and-Trade Program. We understand ARB's intention with regard to entities that exit the Cap-and-Trade Program permanently, but it is unfair for ARB to arbitrarily penalize covered entities that come in and out of the Program based on conditions beyond their control. To this end, we strongly urge ARB to reconsider this proposed amendment and allow retention of such allowances for a period of time, such as 5 years, to allow entities to retain such credits for future compliance obligations when they re-enter the Cap-and Trade Program. (WONDERFUL)

Response: Please refer to the response to 45-day comment B-5.7.

B-5.5. Comment:

Our Santa Maria commercial growing operation is considered a "new entrant" to the cap and trade program, so Windset's source category has not been listed as a regulated category in the cap and trade regulation. As a result, Windset has been ineligible for allocations under cap and trade, requiring us to purchase compliance instruments at considerable expense since we have entered the program. We are very appreciative that CARB has proposed to rectify this matter in the latest proposed rulemaking, allowing Windset to become eligible for allocations. (WINDSET)

Response: Thank you for the support.

B-5.6. Comment:

If Cap-and-Trade continues, do not give out more free allowances. (EJAC)

Response: Please refer to the response for 45-day comment B-5.9, which answers this comment.

B-6. Leakage Prevention

Leakage Studies

B-6.1. Comment:

The paperboard sector is currently in decline, with product demand down nearly 13% from 2010 to 2015. Several consumer buying factors are driving this decline, including preferences for fresh foods over dry grocery, package and product optimization that eliminates packaging material, and packaging substitution that results in switching to plastic containers. Furthermore, state and national extended producer responsibility (EPR) policies, including California, have created further uncertainty for the paperboard sector. Enacting these EPR policies may have the unintended consequence of increasing costs for paperboard while allowing plastic packaging with poor recyclability to become a competitive alternative. All of these trends are not temporary but a permanent part of the changing paperboard market driven by the sustainability movement. As such, we expect our sector to see continued decline through 2030. The assistance factor analyses ARB has conducted thus far has yet to account for market trends. With our sector facing severe headwinds in a permanent decline in demand, we ask that ARB realize that greenhouse gas emissions will be reduced in this secular decline, but please do not exasperate the extremely tough market environment with a reduction in the assistance factor for this sector. (GRAPHICPACKAGING)

Response: See staff's 45-day response to comment B-6.20 for why staff declines to provide allowance allocation for trends unrelated to the Cap-and-Trade Program. See response to 45-day comment B-6.1 for the cost to California consumers and other California businesses of Graphic Packaging's proposed allowance allocation for market trends.

B-6.2. Multiple Comments:

This number is projected to increase to nearly 67% during the period from 2020 to 2030. In this sector, there is a significant level of competition from both international competitors and US firms outside of California, despite the additional cost they bear in shipping to our state. As a result, the threat of leakage is very high. These competitors have cheaper labor costs, lower raw material costs, and lower regulatory burdens, including no cap and trade costs... We strongly recommend that the trade exposure for this sector be revised upward to no less than 67% to accurately reflect our market situation and the very real threat of leakage.

One significant threat is Chinese paperboard firms. In previous discussions with ARB staff, staff have discounted the threat Chinese firms present in our sector, based China's pledge to reduce greenhouse gas emissions under the Paris accord. This is no guarantee. Past pledges by the Chinese government underscore this. There is no

guarantee that greenhouse gas emissions reductions would come from their paperboard mills. To date, our market intelligence has not indicated emission controls at Chinese paperboard mills; nor was it expected. China has actually pledged to reduce greenhouse gas emissions only after 2025. Note that even if they started reducing greenhouse gas emissions in 2026, the Chinese mills will have far greater greenhouse gas intensities (closer to US firms in 2007) making it extremely difficult for California mills with significant greenhouse gas reduction investments to compete. Our market intelligence does indicate that they are increasing the capacity of their paperboard mills, fired on coal and other fossil fuels. We expect them to be a stronger competitor in the 2020-2030 decade than they are now. We expect increased leakage to China with their low cost structure and lack of environmental regulations, including no cap and trade. Similar arguments can be made for our competitors in North and South Korea and Mexico.

After a great deal of review of ARB's assistance factor analyses and proposed assistance factor for the paperboard sector, we recommend that:

1. The trade exposure for the paperboard sector be raised to at least 67% to accurately reflect the highly competitive market that exists with international and non-California US paperboard firms...

5. ARB incorporate market trends into the assistance factor analyses. Such trends give a vital perspective on a sectors ability to absorb a reduced assistance factor. The paperboard sector is in decline and is expected to continue this decline through 2030, making it extremely difficult to absorb the additional burden of a reduced assistance factor under cap and trade. (GRAPHICPACKAGING)

Comment:

Take measures, in implementing the proposed international AF formula, to meet the stated objective of AB 32 to "minimize emissions leakage to the extent feasible" including:...

Project and use trade shares for the post-2020 period to account for the nature of competition prevailing during that, rather than contemporaneous and historical periods. (GALLO)

Response: Commenters request that staff use projections of future business conditions (e.g., industry's estimate of what trade exposure will be in the 2020s) to set assistance factors. See the response to 45-day comment B-6.2 for ARB's preference to use historical or current data, rather than allocate based on projections of future conditions. See staff's response to the first 15-day comment B-6.3 for the definition of trade exposure. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a

rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.3. Comment:

ARB underestimates the trade exposure for paperboard sector at 11% to 14%. In actuality, nearly 60% of paperboard sold in California comes from outside California...

ARB's heavy reliance on just import and export data generate the misleading conclusion that trade exposure for this sector is only a moderate threat. It is in fact a very high threat, one where increased cap and trade costs can cause further leakage of business outside California.

After a great deal of review of ARB's assistance factor analyses and proposed assistance factor for the paperboard sector, we recommend that:..

3. ARB recognize that all other states in the union may never link to California's cap and trade system and are therefore a leakage threat to California businesses. For the paperboard sector, firms from other states, which have lower cost structures and lower regulatory burdens including cap and trade, are a significant threat to leakage. (GRAPHICPACKAGING)

Response: Graphic Packaging has an incorrect understanding of the current definition of trade exposure. Trade exposure is defined as

$$(\text{imports} + \text{exports}) / (\text{total domestic shipments} + \text{imports})^{693}$$

In this equation, established in the 2010 ISOR,⁶⁹⁴ imports and exports are calculated using shipments data on trade with other nations. Therefore, by definition, trade exposure does not capture domestic trade patterns.

See response to 45-day comment B-6.11 for a discussion of allowance allocation for the purpose of domestic leakage prevention.

B-6.4. Multiple Comments:

After a great deal of review of ARB's assistance factor analyses and proposed assistance factor for the paperboard sector, we recommend that:...

4. ARB not consider Chinese paperboard mills on par with California paperboard mills. They are not. In the period from 2020 to 2030, if Chinese paperboard mills begin reducing greenhouse gas emissions after 2025, their emission intensity will be significantly higher than California paperboard mills. (GRAPHICPACKAGING)

⁶⁹³ See definitions of allowance allocation terms in the 2010 ISOR Appendix K: Leakage Analysis, <https://www.arb.ca.gov/regact/2010/capandtrade10/capv4appk.pdf>

⁶⁹⁴ Ibid.

Comment:

For example, we have already seen increasing competition from South America which has reduced our market share in domestic markets. This wine is transported long distances and has a larger carbon footprint. (GALLO)

Comment:

Emissions Leakage may not be one for one. If emissions leakage occurs because production shifts to a less efficient out-of-state facility, with products transported to California to meet in-state demand, then emissions leakage is greater than 1:1. If actual emissions leakage is not 1:1, then ARB is under estimating the potential for leakage by basing their assumptions on a 1:1 exchange. (CCEEB)

Comment:

Furthermore, we believe it is incorrect to assume that there is a one-to-one market transfer rate when it comes to emissions leakage. For example, California currently has some of the most energy efficient, most emission efficient, and least GHG emitting facilities in the world. With the onset of AB 32, California emitters were required to produce lower emissions per metric ton than similarly producing facilities almost anywhere else in the world. As such, there is already a disparity in comparing California and non-California emitters. The third study ARB commissioned by *Hamilton et al.* (determined to be insufficient by ARB) elaborates further on this emission efficiency disparity:

For the case of California food processors, the typical plant operates on natural gas; however, global food processing plants including those in other U.S. states rely on other sources such as coal and fuel oil. In 2002, 52% of total energy supply utilized in the U.S. food manufacturing industry was natural gas, 21% net electricity, 17% coal, 3% fuel oil, and 8% other (e.g., waste materials). In aggregate, the market transfer of California production to producers in other U.S. locations in the U.S. therefore is likely to occur to plants relying on a mix of fuels that produce higher levels of emissions per MBtu. In the case of tomato processing, global market transfer that occurs to food processing facilities in China is likely to result in greater emissions per ton of processed tomatoes, as energy used to process tomatoes in China is generally derived from coal-fired plants.

In light of the challenges outlined with the studies above, we respectfully request that ARB reevaluate its assistance factor methodology prior to finalizing the Staff Proposal. (WONDERFUL)

Comment:

Emission Intensity Differentials: As acknowledged by the authors, neither study accounts for differences in GHG intensity between products produced inside California and products produced outside the state. As a result, neither study takes the final step

in translating estimates of “production leakage” to “emissions leakage.” It stands to reason that most products manufactured in California are likely to have a lower GHG footprint than those produced outside of California due to: (1) the state’s above-average energy prices, which encourages improvements in energy efficiency; (2) the state’s history as a pioneer in environmental policy, which encourages increased use of low-carbon fuels; and (3) the added emissions associated with transporting products from distant markets to be consumed in California.⁶⁹⁵ As a result, the studies’ results are likely to understate emissions leakage in most industries, including the California cement industry.⁶⁹⁶ (CSCME)

Comment:

Leakage Would Result in an Overall Increase in GHG Emissions

In addition to direct compliance requirements for fuel usage, UPI incurs significant Cap-and-Trade costs associated with its electricity consumption. Some of these costs are offset through allocated allowances provided to “trade exposed” industries and certain GHG cost credits to help mitigate electricity cost increases. These adjustments help UPI remain competitive and reduce the risk of losing production to other regions that would probably be less energy efficient and more carbon intensive.

As UPI noted in its comments on the 2030 Target Scoping Plan Update Discussion Draft,⁶⁹⁷ production that is displaced to facilities outside California would emit the same or probably more GHG because production that moves outside of California and is not subject to GHG regulations would be more likely to generate higher overall direct emissions, and higher indirect emissions due to electric generation profiles and increased transportation costs. Therefore, the Cap-and-Trade program should be designed and implemented in a manner that ensures that it will not have the unintended consequence of actually increasing overall GHG emissions. The proposed post-2020 Industry Assistance Factors would drastically reduce UPI’s Industry Assistance Factors from 75% of the compliance obligation in 2020 to 20% in 2021,⁶⁹⁸ resulting in

⁶⁹⁵ It is also worth noting that the displacement of domestic production with out-of-state production is likely to significantly exacerbate non-GHG emissions in the most disadvantaged California communities. For instance, CSCME estimates that each million tons of domestic cement (around 10 percent of California production) that is displaced by imports will result in a shift in approximately 40,000 heavy-duty diesel truck trips (and their associated emissions) from the relatively sparsely populated areas surrounding California cement plants to the more densely populated areas surrounding California ports.

⁶⁹⁶ For instance, all operating cement plants in California already utilize the most advanced and energy efficient technology available and have strong incentives to reduce the GHG intensity of fuel due to the cap-and-trade program. In addition, cement imports are routinely loaded on bulk carriers and transported vast distances to enter the California market, resulting in additional transportation emissions.

⁶⁹⁷ USS-POSCO Industries Comments on 2030 Target Scoping Plan Update Discussion Draft, pgs.1-2, <https://www.arb.ca.gov/lists/com-attach/50-sp2030disc-dec16-ws-Wi9RJwNrUV1SN1U6.pdf> (submitted December 16, 2016).

⁶⁹⁸ First Notice of Public Availability of 15-Day Amendment Text, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, Proposed Regulation Order, Tables 8-1 and 8-3, <https://www.arb.ca.gov/regact/2016/capandtrade16/attacha.pdf>.

significantly increased compliance costs for UPI (especially in light of the declining cap on emissions) and a heightened risk of leakage. (UPI)

Response: Commenters request the use of emissions differentials between in-State production and other jurisdictions' production in determining allowance allocation levels. Staff is unaware of verifiable sources of high-quality information on emissions intensity differentials for every industry listed in Table 8-1. ARB is directed by AB 32 to minimize leakage to the extent feasible. Emissions intensity differentials are used for quantifying the volume of emissions leakage after leakage has already occurred. Therefore, staff did not consider emissions leakage differentials when developing prospective post-2020 assistance factors. Moreover, as part of the second 15-day amendments, all post-2020 assistance factors have been removed. See response to 45-day comment B-6.3 regarding staff's commitment to initiating a deliberative process to establish post-2020 assistance factors in conformance with AB 398.

B-6.5. Comment:

Further, E&J Gallo Winery is the only winery required to be enrolled in the cap-and-trade program, and thus the only California winery that bears the financial burden of compliance allowances. This places our operations at a competitive disadvantage relative to other California wineries, and may result in emissions leakage even within California to the extent that other wineries are more carbon-intensive...

In summary, our recommendations are:...

1. Extend the scope of the 2016 study of emissions leakage risk from California food processing industries conducted by Hamilton, et al. (Hamilton Study) to include grape processing as a means of...
- b. Studying and measuring the potential for emissions leakage risk through market transfer of Gallo's production to other California wineries through marginal compliance costs it faces, but that all other California wineries do not. (GALLO)

Response: EJ Gallo requests that staff consider the impact on its production of non-covered facilities that face no compliance obligation under the Cap-and-Trade Regulation. While California facilities with annual emissions below the 25,000 MTCO_{2e} threshold for inclusion in the Cap-and-Trade Regulation do not have a direct compliance obligation, they still experience a carbon price signal through their energy consumption. Electricity IOUs are, and natural gas IOUs will be, required to pass on the cost of acquiring allowances into rates.

B-6.6. Comment:

We do not believe the ARB has adequately assessed the potential for domestic leakage risk from the wine industry, and we were particularly surprised to learn the ARB determined the domestic AF to be 0. Wine industry competition from Washington, New

York, Oregon, Pennsylvania and elsewhere in the United States has increased dramatically in recent years. As of 2015, these four states now account for 13 percent of domestic wine production.⁶⁹⁹ During 2010-2014, production in other states grew 12.1 percent annually, compared with 3.2 percent annual growth in California.⁷⁰⁰

We are concerned that the ARB determined the domestic AF using the leakage risk measures generated by Gray, Linn and Morgenstern of Resources for the Future, (RFF 2016). We believe this product to be unreliable because it suffers from significant issues in statistical and econometric modeling, and yields a counter-intuitive result for the wine industry...

We believe RFF 2016 is particularly unreliable for the wine industry, and therefore the ARB's determination of a 0 domestic AF based on its results is not appropriate. The model's result that California plants producing wine and related products classified under NAICS code 312130 would *increase* their output relative to plants in other states as natural gas prices paid by California plants *increase* relative to prices in other states runs counter to economic theory. Based on the model, a 5 percent increase in relative natural gas cost would increase our output by the same percentage. On the contrary, economic theory posits a negative relationship between a firm's output and its input costs, including energy.

While RFF 2016 acknowledged that this result contradicts the very economic theory motivating their model, they offer little in the way of explanation. RFF cite that the industries for which this anomalous result occurs have relatively low natural gas cost shares, and that the model produces the expected negative relationship for most industries. We find that explanation to be less than convincing for three reasons.

1. Absence of robust statistical significance of the estimated negative natural gas price elasticities across industries means that many of the estimated negative relationships are actually no different from no relationship at all, in a statistical sense.
2. Comparing industries by natural gas cost share (percent of total production cost) is based on the industry-wide averages for the year 1991 the authors used in the study, a full 25 years ago. For NAICS 312130, RFF reports a 0.29 and 0.40 percent electricity and natural gas cost shares, whereas recent cost shares at our Fresno, California facility are significantly higher.
3. According to Figures 4 and 5 in the October 21, 2016 ARB staff proposal for the AF calculations, negative output elasticities with respect to natural gas prices are estimated

⁶⁹⁹ United States Department of the Treasury Alcohol and Tobacco Tax and Trade Bureau (TTB). 2016. Monthly Wine Statistics, Monthly Statistical Release: Summary – Calendar Year 2015. Available at: <https://www.ttb.gov/statistics/15winestats.shtml>. Accessed January 18, 2017.

⁷⁰⁰ Wine Institute. 2016. US / California Wine Production. Available at: <http://www.wineinstitute.org/resources/statistics/article83>. Accessed January 18, 2017.

for several industry sectors with energy intensity (based on energy cost share) similar to NAICS 312130. (GALLO)

Response: EJ Gallo highlights that the counterintuitive output elasticity for the wine industry, and other features of the domestic study, do not fit the market conditions EJ Gallo experiences. As stated in the second 15-day notice, staff intends to provide industrial allowance allocation at levels sufficient to minimize emissions leakage for the post-2020 period. After the current rulemaking, staff will work with industrial stakeholders and others to establish a post-2020 assistance factor methodology, and will propose assistance factors and industrial allocation for post-2020 compliance periods. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.7. Comment:

In the following we present our concerns with the emissions leakage risk studies and the ARB's determination of the international and domestic AF. Also, we provide recommendations for the ARB's consideration, which we believe will move toward addressing these issues. In summary, our recommendations are:

1. Extend the scope of the 2016 study of emissions leakage risk from California food processing industries conducted by Hamilton, et al. (Hamilton Study) to include grape processing as a means of
 - a. Addressing and correcting the anomalous result derived in RFF 2016 that wine and related production increases as energy prices increase...
 2. Develop quantitative methods to incorporate the effects of general price inflation on non-energy inputs through inter-industry purchasing—a feature that is lacking from the market transfer estimates in the Fowlie, Reguant and Ryan of UC Berkeley (FRR 2016) and RFF 2016 studies.
 3. Take measures, in implementing the proposed international AF formula, to meet the stated objective of AB 32 to “minimize emissions leakage to the extent feasible” including:
 - c. Use the upper limit of the distribution of estimated energy price elasticity ratios.
- (GALLO)

Response: EJ Gallo provides two suggestions for additional research expenditures: extending the Hamilton et. al. study to industries associated with wine production, and estimating the energy effects of inter-industry purchasing (i.e., 1.a. and 2.a. respectively). The latter would require an additional study to run a general equilibrium model. See staff's response to the 45-day comment B-

6.10 for why staff is not considering commissioning new studies or extending current studies (e.g., Hamilton et. al.).

Within the completed studies and available industry or public data, however, see staff's response to comment B-6.12 for staff's consideration of alternate methodologies (e.g., 3.a. of the comment above).

B-6.8. Comment

II. CLARIFYING THE BOARD'S INTENT

CARB's efforts to revise the allowance allocation framework can be traced back to Board Resolution 1132, which directed the Executive Officer to: "continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California, and to recommend to the Board changes to the leakage risk determinations and allowance allocation approach, if needed..."

In response to this directive, CARB commissioned three studies to evaluate the risk of leakage in various industries, including one regarding interstate leakage ("domestic leakage study") and one regarding international leakage ("international leakage study").⁷⁰¹

Based on discussions at the beginning of that process, CSCME was under the impression that the studies would be used to inform and verify the accuracy of its current leakage risk classification — an impression that was recently confirmed by multiple members of the Board. Nevertheless, CARB is proposing to use the results of the studies as the sole and determinative basis for allocating allowances, which represents a radical departure from the current approach.

This radical shift in scope raises questions as to whether the Board is fully informed about the proposed approach, the potential consequences, and the wide range of stakeholder concerns that have been expressed. Accordingly, we request that CARB comment on the following questions:

- Has the Board been fully briefed on the results of the leakage studies?
- Has the Board been fully briefed on the proposed application of the studies' results, including the use of the international market transfer rate as a primary basis for determining industry-specific assistance factors?

⁷⁰¹ CARB has effectively discarded a third study on leakage in the food processor industry because staff, "was not able to follow the calculations by which the study developed its market transfer measurements. Staff also needs to verify that the elasticities from previous literature used inputs for the market transfer calculation that are appropriate for comparison with the elasticities of the other two studies." CSCME has similar concerns regarding the transparency of the data and methods used in the domestic and international leakage studies, as well as the extent to which those two studies can be combined to provide a complete and complementary view of an industry's leakage risk.

- Has the Board been fully briefed on the extraordinary qualifications offered by the authors of the international leakage study regarding the IMT, including the warning that they cannot estimate a transfer rate for any given industry with any degree of confidence?
- Has the Board been fully briefed on the extent and nature of stakeholder concerns regarding the proposed approach, including the lack of transparency in the process, the limitations of the studies results, and the inappropriate application of the studies' results?
- Has the Board approved the use of the studies as the sole and determinative basis for establishing assistance factors?
- Has the Board been fully briefed on the potential consequences of the proposed assistance factors, including the resulting decline in each industry's domestic production, as projected by the studies? In particular, is the Board aware that the leakage studies suggest that, under a \$20 allowance price, the proposed approach will likely result in a reduction in domestic cement production of at least 50 percent? If so, does the Board believe that such a result is consistent with the spirit and letter of AB 32 and, in particular, CARB's requirement to minimize leakage?

III. LEAKAGE RISK & ALLOWANCE ALLOCATION: A BROADER VIEW

3.1 CARB Should Consider All Aspects Of The Allowance Allocation Framework When Evaluating An Industry's Risk of Leakage

CARB asserts that the leakage studies have provided staff with a methodology for developing and applying revised assistance factors, and that this methodology, "would arrive at sector specific revised [assistance factors] to minimize the risk of leakage".⁷⁰² However, the extent to which allowance allocation will minimize leakage in a given industry is not determined solely by the assistance factor. Rather, it is determined by the overall allowance allocation rate (i.e., allowances received per unit of output), which is a function of the assistance factor as well as the product benchmark and the cap adjustment factor. Given that changes to any one of these factors will affect an industry's overall allocation rate, it is important to consider all three of them when evaluating leakage risk.

Under CARB's current approach, both the benchmark and the cap adjustment factor reduce an industry's overall allowance allocation rate. Consequently, even if CARB can successfully identify industry-specific assistance factors that minimize the risk of leakage, the application of the benchmark and the cap adjustment factor ensures that the overall rate of allowance allocation will be less than the rate needed to minimize leakage. In other words, an assistance factor that purportedly minimizes the risk of

⁷⁰² Staff Report: Initial Statement of Reasons (Aug 2016). Appendix E, Page 4.

leakage does not account for the additional leakage risk associated with the cumulative application of the benchmark and cap adjustment factor to reduce allowance allocation.

As a result, CARB's proposed approach will (by definition and design) fail to meet its mandate to minimize leakage. CSCME recommends that CARB establish industry-specific assistance factors that, when combined with an industry's benchmark and the cap adjustment factor, will result in the allowance allocation rate that is needed to minimize leakage risk. (CSCME)

Response: CSCME expresses concern regarding the studies' and staff's methodology's appropriateness in developing assistance factors. See staff's response to the 45-day comment B-6.8. Staff encourages CSCME's participation in the stakeholder process that will inform establishment of post-2020 assistance factors in a subsequent rulemaking, consistent with the requirements of AB 398. See staff's response to 45-day comment B-6.12 regarding CSCME's early participation in proposing alternate assistance factors frameworks for the post-2020 period.

The cement industry submitted comments in the 45-day package regarding the difficulty in reducing some emissions that result from the manufacturing of cement (i.e., process emissions that make it difficult to meet the expected reduction in allowance allocation resulting from the cap adjustment factor). See staff's response to the 45-day comment B-6.12 for the accommodations staff provided to cement and other industries with these process emissions within the existing leakage framework.

B-6.9. Comment:

IV. CARB'S PROPOSED APPROACH DOES NOT MEET BASIC STANDARDS FOR SOUND PUBLIC POLICY

4.1 CARB's Proposed Approach Lacks Transparency & Accountability

CARB's current approach to allowance allocation is based on metrics that are simple, transparent, verifiable, and consistent with those used in other cap-and-trade programs. In contrast, CARB's proposed approach for the post-2020 program is based on two studies that use highly complex methods that many stakeholders do not understand and confidential data that no stakeholder (including CARB staff) can access and verify. Specifically, CARB's proposed approach relies almost exclusively on the results of the leakage studies, which are based on confidential data from the U.S. Census Bureau that cannot be accessed, inspected, or verified by anyone other than the researchers.

The fact that the studies rely on confidential data gives rise to two fundamental issues. First, the regulated community has no ability to verify the accuracy of the underlying data, the analytical methods used, or the final results — creating a regulatory “black box” that lacks transparency and effectively denies the regulated community any

possibility of due process.⁷⁰³ Second, given that only the researchers can access the data, CARB has no ability to verify the accuracy of the data, methods, or results — meaning that CARB has effectively abdicated its regulatory responsibilities and outsourced them to unaccountable third parties.

[The commenter attached, as Exhibit A, correspondence between Meredith Fowlie (one of the leakage study authors) and ARB in 2013. In that correspondence, Fowlie discusses elasticity estimates, noting that they summarize an effect which “is a particularly important driver of leakage” but that the process which generates them “can seem like a “black box” from the outside looking in.” This appears to be the correspondence referred to in the preceding paragraph and footnote.]

Although the use of data that can only be accessed by the researchers may be an acceptable practice for intellectual or academic pursuits, it is an unacceptable basis for formulating public policy that will have a profound consequence on manufacturing facilities, their employees, and the communities that they support. Given this lack of transparency and accountability, CARB should consider alternative approaches in which the studies may inform assessments of leakage risk, but do not constitute the sole and determinative basis for establishing assistance factors (see Section 8).

4.2 CARB Should Subject The Leakage Studies To Peer Review

The lack of public transparency and accountability only heightens the importance of subjecting the studies to a peer review process that would allow an independent assessment of each study’s strengths, weaknesses, and limitations. Despite repeated requests from multiple stakeholders, CARB has refused to establish such a process. Given stakeholder concerns about CARB’s proposed approach and the realworld consequences of allowance allocation decisions, it is irresponsible for CARB to proceed with the rulemaking process without subjecting them to peer review.

4.3 CARB Should Provide Stakeholders With More Time To Analyze Recently Released Data

Although the confidential nature of the raw data that underpins the leakage studies ensures that stakeholders (again, including CARB staff) will never have an opportunity to verify the accuracy of the results, CARB has recently supplied additional data that will allow stakeholders to better understand and validate how CARB is translating those results into assistance factors. We applaud CARB for releasing this essential data. However, we also note that the data was released more than seven months after the studies were released. In contrast, CARB has provided stakeholders with less than a month to review, analyze, and develop thoughtful comments regarding the data. Again, given stakeholder concerns about CARB’s proposed approach and the real-world consequences of allowance allocation decisions, it is irresponsible for CARB to proceed

⁷⁰³ See Exhibit 1.

with the rulemaking process before it provides stakeholders with adequate time to fully evaluate this essential data.⁷⁰⁴

V. CONCERNS COMMON TO BOTH STUDIES

5.1 Both Studies Are Based On Flawed Assumptions

At a high level, both the domestic and international leakage studies use the same two-step process: (1) analyze historical data to estimate the relationship between energy prices and key outcomes for individual industries and (2) simulate the effect of a given carbon price on individual industries. In making the leap from the first step to the second step, the authors of both studies must make several explicit and implicit assumptions that are unlikely to hold true in reality, including:

- Assumption #1: The conditions of competition within an industry will not change in response to a carbon price impact. The studies calculate an industry's response to past variations in energy prices, and then assume that those historical relationships will hold regardless of the carbon price. In reality, however, there is a price point at which an industry's market structure (especially trade patterns) will fundamentally shift in response to the policy intervention. To the extent that a carbon price changes the conditions of competition in an industry, the studies are likely to understate future impacts, especially for emissions-intensive industries such as cement.⁷⁰⁵
- Assumption #2: The energy cost impacts observed in the past are likely to be similar to the carbon price impacts experienced in the future. The studies assume that the magnitude of energy price changes in the past will be similar to the magnitude of carbon price changes in the future. Yet, according to the international leakage study, "The magnitude of the energy price impacts associated with a \$10 to \$15 per metric ton of CO₂ carbon price lie within the scale of the variation in relative energy prices that we will use to identify impacts on production and trade flow."⁷⁰⁶ Given that the allowance price floor is estimated to be approximately \$20 per metric ton of CO₂ in 2025, it is clear that the energy price impacts observed in the studies is likely to be at least 25-50 percent lower than the carbon price impacts after 2020. To the extent that carbon price

⁷⁰⁴ On a related note, CSCME has not been able to replicate the IMT calculations using the data provided by CARB. As one example, in the worksheet labeled "berkeley data", the ratio of "imp_p50" and "prod_p50" elasticities does not appear to equal the values for "ratio_imp_p50." Given that all values are hard coded into the spreadsheet, it is impossible to trace through the actual calculations. To the extent that CSCME is misinterpreting the data, we would appreciate clarification from CARB staff. To the extent that the data is incorrect, we recommend that CARB: (1) issue the correct data; (2) comment on the source and nature of the error; and (3) comment on whether, how, and the extent to which the error affects any values contained in the proposed regulation.

⁷⁰⁵ This is particularly true for the international leakage study, which estimates import and export elasticities. Although domestic producers are effectively "locked in" to their existing capital stock, trade flows can swiftly shift as foreign producers redirect their product to the California market to take advantage of their policy-induced cost advantage.

⁷⁰⁶ Fowlie, M.L. et al., "Measuring Leakage Risk" (May 2016), ("International Leakage Study"), p 29.

impacts are non-linear at higher values, the studies are likely to understate the future impacts, especially for emissions-intensive industries such as cement.

- Assumption #3: An industry's response to a transitory, market-driven, and relatively "private" cost impact is likely to be similar to its response to a permanent, policy-driven, and relatively "public" cost impact. An industry's response to a temporary cost impact (i.e., a market-driven change in natural gas prices) is likely to be different than its response to an unambiguously permanent cost impact (i.e., a policy-driven cost increase via carbon pricing). Likewise, an industry's response to energy prices that have gradually evolved over many years is likely to be different than its response to the sudden cost increase that would occur with a change in policy. Finally, a competitor's response to a relatively private cost impact, such as changes in a California producer's energy costs, are likely to be different than its response to a public cost impact, such as a carbon price, which clearly signals an opportunity for out-of-state producers.

5.2 Both Studies Omit Factors That Are Critical To Accurately Measuring Leakage Risk

- Other Costs Associated with AB 32: Both studies estimate the direct compliance costs associated with the cap-and-trade program and ignore the cost impacts associated with other AB 32 measures and requirements, such as the renewable portfolio standard, the low carbon fuel standard, administrative fees, and compliance activities. Some of these costs are relatively large and some are relatively small, but all of them add to the collective financial burden associated with AB 32 and, therefore, should be considered when estimating the risk of leakage associated with it. As a result, the studies are likely to understate the risk of emissions leakage in most industries, including the California cement industry.

- Process Emissions: Both studies explicitly do not model the impact of process emissions, despite the fact that: (1) process emissions make up a substantial portion of the GHG footprint for several industries; (2) the data needed to account for process emissions was readily available from CARB; and (3) incorporating process emissions directly into the models and simulations is a relatively straightforward task. For instance, process emissions constitute almost 60 percent of the cement industry's GHG intensity, which suggests that the impact on the industry should be at least 2.5 times higher than estimated by the studies.⁷⁰⁷ More generally, to the extent that an industry produces process emissions, the studies are likely to understate the risk of emissions leakage in that industry, including the California cement industry.⁷⁰⁸

⁷⁰⁷ A 60 percent process emissions ratio suggests that each unit of combustion-related emissions is associated with 1.5 units of process-related emissions — resulting in a total of 2.5 units of emissions. Note that a 2.5 multiple assumes that the industry's production, import, and export response functions are linear. To the extent that the response functions are non-linear at higher carbon price values, the process emissions adjust is likely to be incomplete and, therefore, the adjusted elasticities will likely understate the risk of emissions leakage.

⁷⁰⁸ To its credit, CARB attempts to correct for this deficiency when translating the studies' results into assistance factors. However, that adjustment process is incomplete and a significant bias remains.

Inter-Industry Leakage: Both studies attempt to evaluate the potential for intra-industry leakage (e.g., shifts in production across state lines within an industry), but neither evaluates the potential for inter-industry leakage (e.g., shifts in production across state lines among multiple industries). For instance, California cement producers compete for market share against out-of-state cement producers, as well as producers of other construction materials, including asphalt, steel, and lumber. To the extent that a carbon price results in a shift in market share to substitute products that are manufactured outside the state and transported to California for consumption, the modeling results are likely to understate the risk of emissions leakage in industries that compete with other products, including the California cement industry...

VI. CONCERNS SPECIFIC TO THE INTERNATIONAL LEAKAGE STUDY

6.1 The International Leakage Study Is A National Study That Does Not Adequately Reflect The Conditions Of Competition In The California Cement Industry

The international leakage study is an analysis of national industries, yet the national cement industry and the California cement industry are fundamentally different in important respects. As evidenced by more than two decades of U.S. International Trade Commission rulings, the California cement industry is a distinct regional market that operates in a competitive environment that is fundamentally different than cement industries in other U.S. regions or the United States as a whole. Unlike inland states, the California market is logistically and economically accessible by seaborne vessels from virtually every port in the Asia Pacific region, which amplifies the threat of imports and forces domestic producers to proactively suppress prices to maintain market share and achieve the high utilization rates needed in a capital-intensive industry. On the other hand, the California cement industry exports very little cement due to structural, geographic, and political barriers. As a result, the international leakage study's national approach is unlikely to accurately predict the impact of a carbon price on the California cement industry.⁷⁰⁹

[The commenter attached, as Exhibit B, referred to in the preceding footnote, excerpts from a research plan proposed to ARB by Fowlie et al. at the onset of the research contract. The excerpts contain the quote given in the footnote.]

(CSCME)

Response: CSCME raises concerns regarding the fit of the studies to the market environment CSCME perceives they operate under. See staff's response to the

⁷⁰⁹ See Exhibit 2. In an initial proposal to CARB to analyze the leakage in the cement industry, the study's authors make this same general point. Specifically, they state, "Ideally, these data will allow us to differentiate across regional markets (e.g. west coast versus Southern Tier), across import transaction type (e.g., intrafirm versus arms' length) and, possibly, across points of origin (i.e., Asia versus Europe). This is particularly important in the case of cement, where recent empirical work has documented striking heterogeneity in import responses across regions (Cohen-Meidan, 2011). Additionally, the authors state that, "there is convincing evidence to suggest that import supply elasticities vary significant both across and within regional cement markets (Cohen-Meidan, 2010)."

45-day comment B-6.7 for a discussion of the process by which staff will address these and other concerns regarding the studies. See staff's response to the 45-day comment B-6.12 for a discussion of the proposed assistance factor methodology's accommodations of process emissions. Staff encourages CSCME to participate in the subsequent rulemaking to establish post-2020 assistance factors consistent with the requirements of AB 398.

B-6.10. Comment:

Peer Review Called for on Domestic and International Leakage Studies

CLFP continues to question ARB staff's reliance on the domestic and international leakage studies (Gray et al. 2016; Fowlie et al. 2016) absent legitimate peer review. Affected industries will be harmed by significant new costs when industry assistance levels are scheduled to decline in the fourth compliance period of the cap-and-trade program. This treatment of vulnerable California industries will impede continued economic recovery and limit mid-level job creation and undermine the important goal in SB 32 to minimize leakage of emissions and jobs out of state.

Lacking solid and reliable evidence to the contrary, it is not only reasonable, but highly likely, that higher costs on industries engendered in the proposed assistance factors will promote leakage among California industries.

Affected stakeholders have provided comments raising concerns regarding the conclusions in the domestic and international leakage studies regarding data limitations and methodological choices which may contribute to the underestimation of emissions leakage risk. If true, the evidence generated by Gray et al. 2016 and Fowlie et al. 2016 may be too uncertain to distinguish among industry leakage risks at standard levels of economic certainty.

Without further review, it is arbitrary for ARB to assign high assistance factors to some industries and low AFs to others. In so doing, ARB staff has created a situation, that may result in undeserved losses to some industries and generate relative windfall gains to others.

This uncertainty is further compounded by ARB staff's admission to manipulation of the results of the studies. By manipulating these results, ARB effectively exposes all its estimates of industry-specific leakage to similar errors.

Without question, industry-specific analyses would generate more credible, data-supported estimates of leakage risks by accounting for differences in market characteristics across industries and should be employed at every opportunity in order to avoid worsening leakage and damage to the state's economy...

Extension of Cap-and-Trade in Fourth Compliance Period

In general, CLFP supports the current program and designed methodology for allocating allowances to the industrial sectors and would like to see it continue post-2020 in something resembling its current form.

Over the past two compliance periods food processors, as well as other industrials, have gained a measure of confidence in the operations of the cap-and-trade market in its current form. However, the proposed assistance factors based on the two ARB-commissioned leakage studies (Fowlie et al. 2016, Gray et al. 2016) have reintroduced the uncertainty that has plagued business and industry since the beginning of this program.

Additionally, neither of the proposed alternatives (Option 1 and Option 2) offers any significant improvement over the current market mechanism.

Food Processor Leakage Study (Hamilton et al. 2016)

The question remains on how CARB intends to use the agency-funded Cal Poly study (Hamilton et al. 2016) for determining allowance allocations to the food processing industry.

In Attachment B, ARB staff states that the ARB-commissioned food processor study (Hamilton et al. 2016) was not used in the development of the assistance factors due to the need for continued analysis of the best means by which to integrate its findings.

While CLFP encourages ARB staff to utilize the Hamilton et al. 2016 study in the development of post-2020 assistance factors, this was not the original intention behind CARB commissioning the food processing industry study.

The impetus behind the agency's approval of the Hamilton et al. 2016 was the lack of accurate and relevant industry data to support CARB's initial assignment of a medium leakage risk designation for the food processing industries. This agency-funded sector study was designed to provide accurate industry data for use in determining the leakage risk for the sector (NAICS §311 and §312) under AB 32 and the current Cap-and-Trade regulation, not post-2020.

For the food processing industry, Hamilton et al. 2016 provides clear direction for CARB. As it makes a strong and unrefuted argument, supported by facility-level data, for continuing 100% transition assistance for food processors beginning 2018.

(FOODPROCESSORS)

Response: CLFP encourages staff to develop “industry-specific analysis... [to] account for differences in market characteristics across industries.” See staff's response to 45-day comment B-6.10 for staff's thoughts on extending existing studies (i.e., the Hamilton study) or relying on studies commissioned by industry that could fall short of treating all industrial sectors equally in establishing post-2020 assistance factors. Within the framework of the three existing studies, as

well as historical or current industrial data, staff is open to considering alternate methodologies. Notwithstanding this, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Measurement Metrics

B-6.11. Comment:

VII. CONCERNS ABOUT CARB'S APPLICATION OF THE STUDIES' RESULTS

7.1 CARB'S "Two-Study" Approach Results In Substantial Internal Inconsistencies

Both leakage studies follow the same core approach to estimating the impact of a carbon price on California industries: (1) estimate an industry's output response due to a change in input costs (namely, natural gas and electricity costs) and (2) use those estimates to simulate an industry's output response under a given carbon price. Provided that the output responses are adjusted to reflect a common carbon price assumption, these headline results can be considered roughly comparable across industries and across studies – effectively an “apples and apples” estimate of industries' output response to a carbon price.

However, the international leakage study goes one step further than the domestic leakage study by estimating the international market transfer rate, or the share of an industry's output response that is “transferred” to international producers. This post-hoc calculation places the studies on unequal footing – effectively turning an “apple” into an “orange”. Because the domestic leakage study does not provide an estimate that is comparable to the market transfer rate, CARB is proposing to make its own post-hoc adjustment to the domestic study's output response. However, it does so through an entirely different approach than the international leakage study (i.e., the “domestic drop cutoff” concept) — effectively turning the other “apple” into a “pear.” In short, CARB is applying very different adjustments to very different measures, which results in an “oranges and pears” comparison that raises significant questions about whether it is technically valid to simply add the two measures together, as CARB has proposed.

7.2 CARB's Efforts To Account For Process Emissions Are Deficient

As previously discussed, neither leakage study explicitly accounts for process emissions in their modeling frameworks. As a result, CARB is left to make post-hoc adjustments to the studies' results to avoid adopting a methodology that significantly and systematically underestimates leakage risk. Unfortunately, CARB's efforts to make these adjustments are technically flawed and incomplete. Specifically, CARB makes no attempt to scale up the studies' original output responses to account for process emissions, uses the unadjusted output responses as inputs into its “alternative” methodology, and effectively unwinds the adjustments that it does attempt to make by

averaging adjusted (e.g., regressed DD) and unadjusted (e.g., raw DD) estimates to calculate assistance factors. These methodological half measures result in a systematic underestimation of leakage risk for industries with a significant amount of process emissions, including the California cement industry.

- CARB Fails To Adjust The Original Output Responses For Process Emissions

CARB makes no attempt to scale the studies' original output responses to account for process emissions. In the case of the domestic leakage study in particular, adjusting the original output and value added estimates is relatively straightforward. Specifically, DD increases in a linear fashion with respect to price shocks, and there is no true distinction between fuel emissions and process emissions. As a result, the raw domestic drop measures can be directly scaled according to each industry's process emissions intensity by dividing the measures by the share of combustion-related emissions (i.e., one minus the process emissions ratio).

In the case of the international leakage study, the same approach can be used to scale the study's production, import, and export elasticities. However, note that this adjustment would have no bearing on the IMT rate, as the ratio of the elasticities used in the calculations will remain unchanged. The fact that adjusting for process emissions in the production, import, and export measures does not affect IMT values only underscores its flaws as a measure of leakage risk.

Making this adjustment for process emissions can result in materially different estimates of domestic drop. For instance, adjusting domestic drop estimates for the cement industry to account for process emissions would increase the DD on a value-added basis from 25 percent to 63 percent, and increase the DD on an output basis from 20 percent to 52 percent.⁷¹⁰

- CARB Fails To Fully Account For Process Emissions In Its Regressions

CARB's failure to directly adjust raw leakage measures to account for process emissions also impacts its alternative methodology. Specifically, although CARB adjusts the right-hand variables in each regression (e.g., energy intensity) to account for process emissions, it fails to adjust the left-hand variables (IMT or DD) in a similar fashion. In other words, CARB's process emissions "adjustment" via the regression IMT and DD measures makes only one adjustment for process emissions, when three are necessary.⁷¹¹ This incomplete adjustment process biases regression estimates and,

⁷¹⁰ Calculations to adjust the domestic leakage study's original output and value-added responses for process emissions were performed using CARB's *F* values for the International AF Component Purchased Fuels Ratio, in Table 1 of Attachment B.

⁷¹¹ It is worth noting that there are no conceptual or technical barriers to directly adjusting the study's results to account for process emissions, and the reasons why CARB failed to do so prior to the most recent release is unclear.

therefore, systematically underestimates leakage risk for all industries, but particularly those with a significant share of process emissions.

- CARB Effectively Unwinds its Process Emissions Adjustment by Averaging Across Metrics

Not only does CARB fail to adjust the studies' raw IMT and DD output measures before using them as inputs to its regressed estimates, but it then proceeds to unwind the limited adjustments that it does make by averaging the post-2020 assistance factors associated with the adjusted regressed IMT and DD estimates with those associated with the unadjusted raw estimates. CARB's decision to average, rather than take the highest IMT and DD estimates, systematically penalizes industries with a significant share of process emissions.

- CARB Should Revise Its Approach To More Fully Account For Process Emissions

CARB should revise its process emissions adjustment methodology and calculate the domestic assistance factor component according to the following steps:⁷¹²

Scale the study's raw output measures to account for process emissions;

Use the scaled measures as inputs to CARB's regression estimates; and

Base assistance factor components on the highest measure of DD.

To illustrate the extent of the bias in CARB's proposed approach, consider the case of the California cement industry. Under CARB's current methodology, the domestic assistance factor component is 0.675. In contrast, if one makes the necessary process emissions adjustments to the raw DD measures, uses those scaled measures as the left-hand side variables of the regressed DD measures, and takes the highest of the four possible DD measures, the cement industry's estimated domestic assistance factor increases to 0.9 (see Figure 6). If a similar approach were applied consistently throughout CARB's methodology, the the cement industry's post-2020 assistance factor would be 1.0 rather than 0.74 under CARB's proposed framework (see Figure 7). The fact that methodological missteps of this nature can result in a dramatically lower assistance factor only emphasizes the need for CARB to more carefully reassess every aspect of its proposed approach.

7.3 CARB's "Regressed" Measures Disadvantage Industries Most At Risk Of Leakage

CARB attempts to address certain deficiencies associated with the leakage study results by using regression analysis to estimate "alternate" measures. Unfortunately, CARB's proposed approach fails to fully address the flaws inherent in the original metrics, contains technical missteps, and is applied in a manner that systematically

⁷¹² Again, the nature of the IMT metric precludes us from proposing any methodological adjustments short of removing it as an input to this process.

penalizes certain industries, such as those with significant process emissions. For instance:

The “regressed IMT” uses the “raw IMT” as the left-hand variable and, consequently, does not address the deficiencies of the underlying measure — in fact, it perpetuates and amplifies them. For example, one of the most significant flaws of the “raw IMT” estimates is that it is almost perfectly correlated with trade intensity (see Section 6.2). By including trade intensity as a right-hand side variable, CARB’s regressed IMT does not address this defect — it effectively doubles down on it.

CARB uses energy intensity as a right-hand variable in its IMT and DD regressions, despite the fact that GHG emissions intensity is clearly a more relevant and reliable proxy for leakage risk. Energy intensity should only be used in the absence of reliable emissions intensity data, which is available and accessible for all industries that are subject to the mandatory reporting requirement.

By estimating a regression across all industries in the manufacturing sector, the regressed IMT and DD measures effectively “force” each industry to conform to an industrial sector norm — thereby “unwinding” the industry-specific results that the studies were intended to produce. As a result, individual industries that have IMT or DD estimates above trend are systematically penalized while individual industries that have IMT or DD estimates below trend rewarded. The practical implications of this compression toward an industrial sector norm were previously mitigated by the fact that CARB was proposing to use the greater of the raw IMT and the regressed IMT.⁷¹³ However, CARB has inexplicably changed its methodology to average the original and regressed measures, which decreases assistance factors for industries that have IMT and DD measures that are “above average.” Such a result conflicts with the basic intent of the allowance allocation framework (i.e., provide relatively higher levels of allowance allocation to industries that have relatively higher leakage risk, and vice versa).

7.4 CARB’s Domestic Drop “Cut Off” Is Conceptually Incoherent & Poorly Executed

The DD cutoff rate represents CARB’s estimate of a “typical” output decline in the manufacturing sector

(in the absence of a carbon price), which CARB then uses as an assumption for the share of an industry’s DD that would not be “transferred” to non-California producers. The DD cutoff is a misguided attempt to align the results of the domestic leakage study with those of the international leakage study, as opposed to discarding the IMT and

⁷¹³ Staff Report: Initial Statement of Reasons (Aug 2016). Appendix E, Page 7. Specifically, CARB states that, “staff proposes additional levels of caution in establishing revised AFs for each sector. Additional IMT and DD values would be proposed for each sector based on alternate methodologies explained below. Each time the application of an alternate IMT or DD methodology resulted in a higher total revised AF, staff would award this higher revised AF from the alternate approach.”

using the production elasticities common to both studies to integrate them on an “apples-to-apples” basis.

That critical issue notwithstanding, the DD cutoff concept is methodologically flawed in at least two respects: (1) the historical data used to construct the measure does not provide any insights into whether or not past output declines resulted in economic leakage; and (2) the concept relies on selectively chosen, historical production data to make predictions about the future.

First, as a threshold matter, the DD cutoff rate cannot in fact reject or confirm the assumption that there is a one-for-one relationship between output drop and leakage. Specifically, the way in which CARB has presented and applied the DD cutoff rate implies that any output decline of less than 7 percent in the manufacturing sector is “typical” or even “acceptable”, and that we should not expect such production to be transferred to a jurisdiction outside of California (i.e., leakage). In fact, the NBER data used to construct the cutoff rate provides no insights whatsoever into what actually happened to the “lost” output in years in which there was a decline. In other words, it is agnostic as to whether that average 7 percent decline was simply lost demand, or whether it was replaced by foreign supply. Rather, the data simply provides a retrospective view into how much output tends to fluctuate.

Second, CARB’s calculation of the threshold is conceptually incoherent and unnecessarily complex. CARB calculates the domestic drop cutoff as an average of three different measures: (1) the average decline in production across all available industries and all available years given that there was a decline; (2) the average decline in production across all available industries and all years prior to the Great Recession given that there was a decline; and (3) one-half of the average standard deviation across all industries and all years. CARB provides no explanation or rationale for why any of these three measures offer a better alternative to the one-for-one assumption, much less why the average of the three numbers is likely to produce a less arbitrary or more reliable estimate.

Figure 5: Raw DD vs. PE-Adjusted DD (Value-Added)

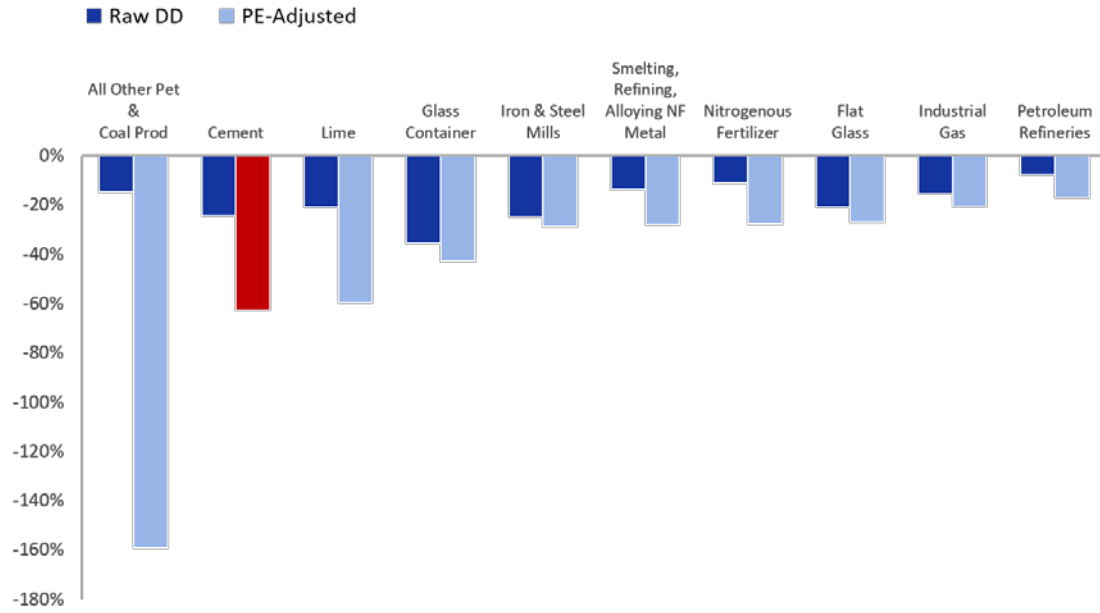


Figure 6: CARB Average Domestic AF vs. Peak Domestic AF (PE-Adjusted)

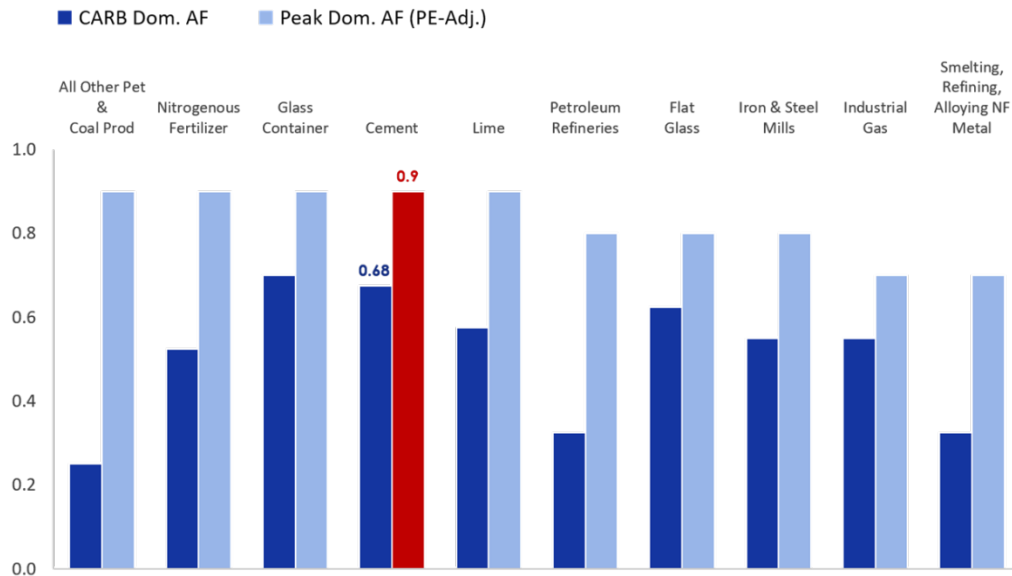
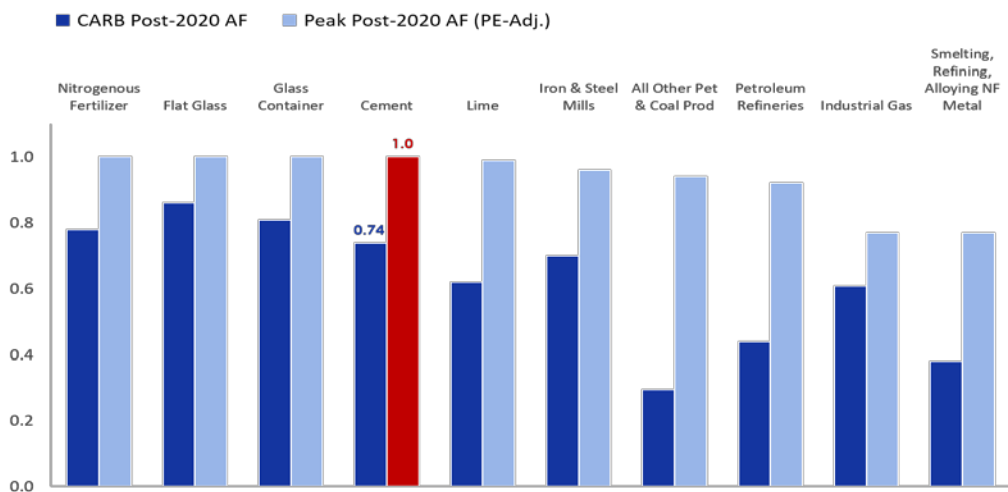


Figure 7: CARB Post-2020 AF vs. Peak Post-2020 AF (PE-Adjusted)*



* The "peak" assistance factor includes the highest DD component after adjusting the raw DD measures for process emissions, and the higher of the raw IMT and regression IMT values.

[The commenter attached, as Exhibit C, excerpts from an interim research contract report provided to ARB by Fowlie et al., regarding their leakage study. The excerpts discuss trade exposure and leakage measures.] (CSCME)

Response: CSCME highlights concerns about staff’s application of the study results. See staff’s response to comment B-6.9 for a discussion of staff’s planned incorporation of CSCME and other stakeholder feedback on the studies and California industries during a subsequent rulemaking to establish post-2020 assistance factors. In addition, see response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking, and have been removed from this rulemaking. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.12. Comment:

CARB’s current approach to allowance allocation provides a decreasing amount of allowances per unit of output produced. Under this framework, the cement industry, which is currently classified in the high leakage risk category, will receive 0.73 allowances for every ton of cement output in 2020 — roughly 8 percent lower than the GHG intensity of the industry’s “best performer” prior to the start of the program. Under a “business-as-usual” scenario, the cement industry’s allocation rate would decline to 0.60 allowances per metric ton of cement output in 2030.⁷¹⁴ As a point-of-reference, each metric ton of cement clinker generates 0.54 metric tons of process emissions, which are a natural and unalterable consequence of the chemical process needed to manufacture cement. In short, under a business-as-usual scenario, the cement industry’s allowance allocation rate is likely to be below an emissions rate that is practically and technically achievable, much less economically and financially sustainable.⁷¹⁵ Nevertheless, CARB is proposing a new allowance allocation framework that is a radical departure from the current approach and would result in substantially lower allowance allocation rates for virtually every industry, including cement. Although all three components of the allowance allocation framework (i.e., benchmark, assistance

⁷¹⁴ For this particular simulation, we assume that the benchmark and assistance factor remain constant, but the cap adjustment factor declines consistent with Table 9-2 of the proposed modifications.

⁷¹⁵ Against this backdrop, it is also worth noting that CARB has failed to fully explore the feasibility of implementing an incremental border carbon adjustment (BCA), as directed by the Board in 2010 via Resolution 10-42. As expressed to CARB on multiple occasions, even under a business-as-usual scenario in which the current allowance allocation framework is maintained but the allocation rate continues to decline due to the cap adjustment factor, a BCA will be essential to ensuring that cement importers face compliance obligations that are comparable to those faced by California cement manufacturers under the cap-and-trade program — thereby minimizing leakage risk. To the extent that the cement industry’s overall allocation rate is reduced beyond the rate associated with a business-as-usual scenario, the urgency and importance of implementing an effective BCA will only grow.

factor, and cap adjustment factor) are essential to minimizing leakage risk, the vast majority of the decline in allowance allocation rates is due to CARB's proposed assistance factors. Accordingly, CARB's proposed approach to establishing assistance factors merits special scrutiny to ensure that it is conceptually and technically sound, clearly superior to both the current approach and other viable alternatives, and that it complies with CARB's statutory obligations under AB 32.

The proposed allowance allocation framework fails to satisfy CARB's requirement to minimize emissions leakage,⁷¹⁶ and the cement industry represents a textbook example of that failure. As illustrated in Figure 1, under CARB's proposed approach, the cement industry's allocation rate would decrease overnight from 0.72 in 2020 to 0.53 in 2021 (i.e., less than the amount of process emissions associated with each metric ton of cement clinker produced).⁷¹⁷ According to the same studies that CARB has used to establish post-2020 assistance factors, such a decline in the industry's allocation rate would decimate the domestic cement industry. For instance, the results of the international leakage study suggest that, even after accounting for allowance allocations under CARB's proposed framework, an allowance price of just \$20 would cause California cement production to decline by 46 percent (see Figure 2).⁷¹⁸

In proposing such a framework, CARB has effectively taken the indefensible position that a 46 percent decline in domestic production is consistent with the spirit and the letter of AB 32 in general and with CARB's requirement to minimize leakage in particular.⁷¹⁹ The absurdity of that conclusion is indicative of a much more systemic problem: CARB's proposed approach to establishing assistance factors is logically inconsistent, conceptually unsound, technically deficient, and poorly executed at virtually every step of the process. For instance:

Overall Analytical Approach: CARB's proposed approach attempts to combine different metrics from different studies using different data, different methods, and different assumptions — resulting in separate measures for “domestic” and “international”

⁷¹⁶ . In addition to failing to minimize leakage and requiring reductions that are not technologically feasible, CARB's proposed approach undermines other statutory requirements under AB 32 because the proposed regulation is not “equitable,” does not seek to “minimize costs,” and does not consider “cost-effectiveness.” AB32, Sections 38562(a), (b)(1), (b)(5), and (b)(8)

⁷¹⁷ This calculation assumes that the assistance factor is lowered to 0.74 and the cap adjustment factor declines as outlined in Table 9-2 of the proposed regulation. It also assumes that the cement industry's benchmark remains at its current level. To the extent that the benchmark is also lowered, the impacts on the industry will be even more severe than described here.

⁷¹⁸ According to the international leakage study, a \$10 allowance price will result in a 72 percent reduction in domestic production in the absence of allowance allocation. Given an allocation rate of 0.54 and assuming that the industry's average GHG intensity equals 0.79 in 2021 (i.e., the GHG intensity of the industry “best performer” at the start of the cap-and-trade program), CARB's proposed approach would offset roughly 68 percent $[0.54/0.79]$ of the impact or, alternatively, 49 percent of the 72 percent decline. This would result in a 23 percent decline in domestic production, which translates into a 46 percent decline under a more realistic allowance price assumption of \$20 in 2021.

⁷¹⁹ Note that this illustrative example does not consider the impacts associated with “domestic leakage” and, consequently, is likely to dramatically understate the potential impacts.

leakage that are “oranges and pears” and cannot be combined to provide a complete and accurate picture of leakage risk.

Identifying Valid Leakage Measures: CARB’s proposed approach relies on the “international market transfer” (IMT) rate from the international leakage study, which consists of several conceptual and technical flaws that make it unsuitable for use in formulating public policy. For example: (a) the IMT calculation produces illogical results for 16 percent of the industries modeled; (b) an industry’s IMT rate does not vary with alternative carbon price assumptions (i.e., the estimated leakage risk is the same regardless of whether one assumes a \$1, \$100, or \$1,000 carbon price); and (c) an industry’s IMT rate is almost perfectly correlated with its trade share (i.e., it adds no informational value beyond the trade shares used in CARB’s current approach, which is much more simple, accessible, and intuitive).

Accounting for Process Emissions: CARB’s proposed approach relies on studies that explicitly do not consider the impact of process emissions, which significantly and systematically biases the results for certain industries, including the cement industry. CARB’s attempts to address this deficiency are incomplete and do not successfully address this bias, resulting in artificially low assistance factors for several process emissions-intensive industries.

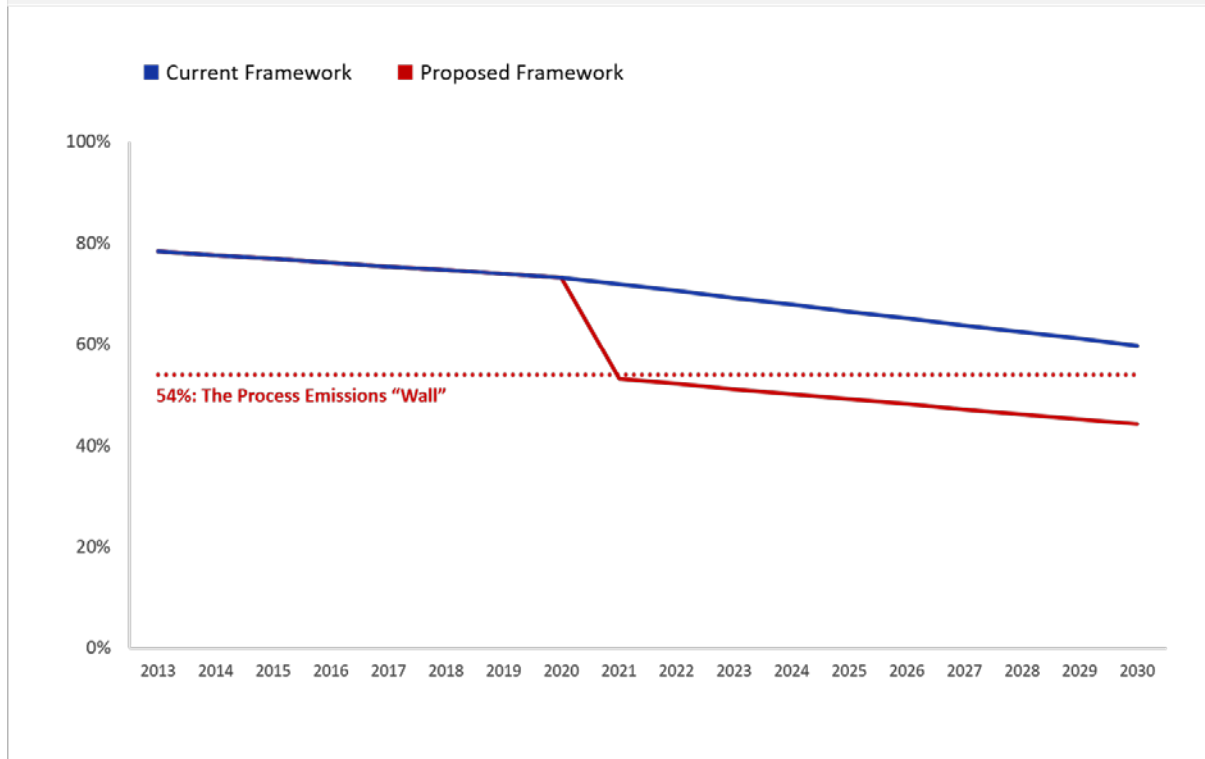
Calculating Assistance Factors: CARB’s overall methodology for translating the studies’ results into assistance factors is conceptually incoherent and unnecessarily complex. For instance, an industry’s assistance factor is determined by combining: (a) one “original” measure of international leakage risk calculated by the researchers; (b) one “derivative” measure of international leakage risk calculated by CARB staff; (c) two “original” measures of domestic leakage risk calculated by the researchers but with adjustments by CARB staff; and (d) two “derivative” measures of domestic leakage risk calculated and adjusted by CARB staff. The complexity of this process is a reflection of the deficiencies that permeate the underlying measures, as well as the misguided view that simply averaging together more measures will somehow eliminate those deficiencies.

Many of these issues (and others) have been expressed in previous comment letters by CSCME and other stakeholders. CSCME is deeply concerned that, despite extensive feedback, the most recent proposal is virtually identical to the prior version. CARB has provided no indication that it has seriously reassessed its proposed approach in light of this feedback or seriously considered the merits of alternative approaches that have the potential to address stakeholder concerns.

This comment letter reiterates concerns expressed previously and also elaborates on new issues that have come to light as a result of CARB’s latest proposal and documents

recently obtained through a Public Records Act request.⁷²⁰ It also offers alternative approaches that address many (though not all) concerns that have been expressed by stakeholders.⁷²¹ CSCME looks forward to continuing to work with CARB to modify its proposed approach and establish an allowance allocation framework that will minimize emissions leakage in the cement industry and other industrial sectors.

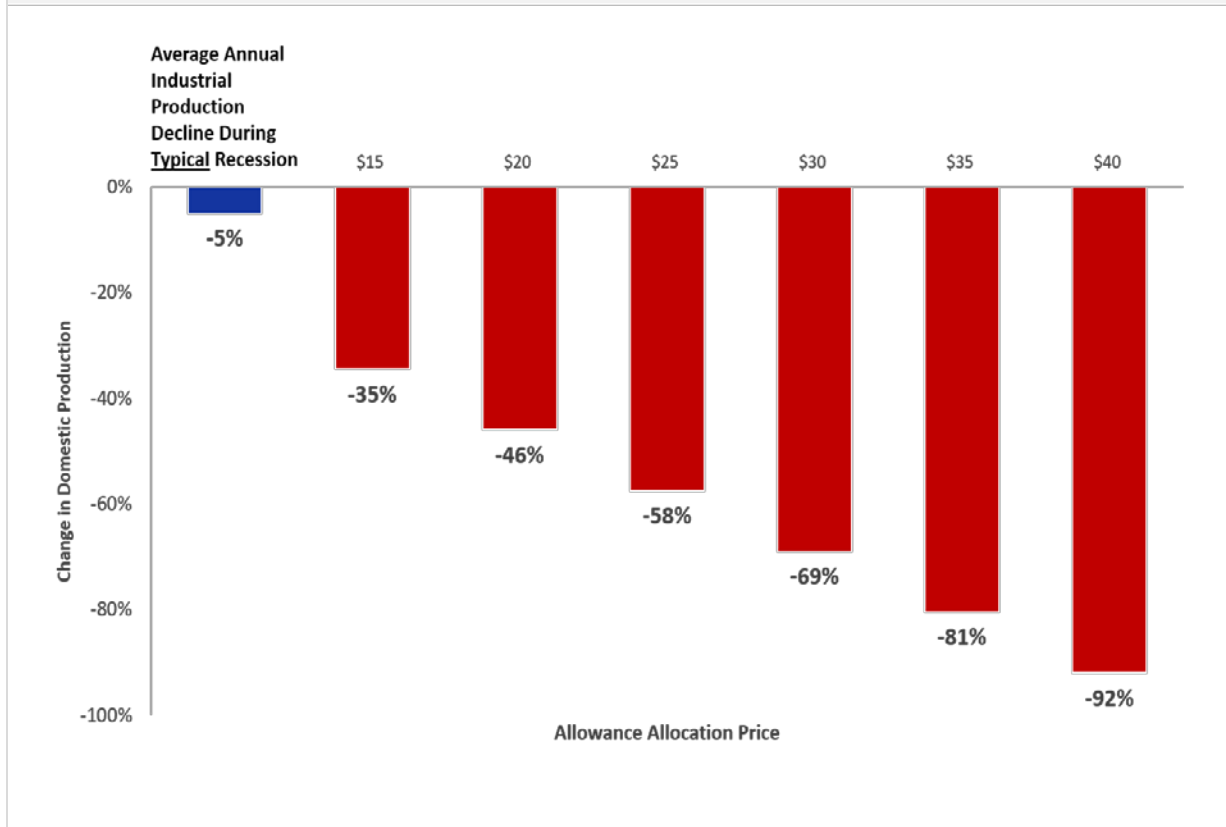
Figure 1: Allocation Rate for the Cement Industry, Current vs. Proposed



⁷²⁰ CSCME is continuing to review the documents provided under the Public Records Act request, and we may augment these comments as new issues come to light.

⁷²¹ Several flaws cannot be resolved because they are endemic to CARB's original decision to commission different studies to analyze different dimensions of leakage risk using different inputs, assumptions, methods, and output metrics (as opposed to commissioning a single study that evaluates leakage risk in general using an internally consistent methodology). CARB's decision to commission studies that rely on confidential (i.e., unverifiable) data only compounds this issue, as it makes it impossible for stakeholders (including CARB staff) to fully evaluate the strengths, weaknesses, and limitations of the studies, much less their relation to one another.

Figure 2: Change in Cement Production at Different Allowance Prices



VIII. ALTERNATE APPROACHES

Momentarily putting aside our technical concerns with the studies, CSCME understands that CARB is interested in using the leakage study results to inform the assignment of an assistance factor for each industry. Regardless of what approach is used, we believe that it is essential that CARB adhere to three fundamental principles:

Use estimates that were actually modeled results from the studies (i.e., output or value-added responses);

Adjust those estimates to account for known deficiencies (e.g., not considering the impact of process emissions when estimating the size of the output response);

Ensure that the results of the two studies are on an “apples-to-apples” basis before they are combined (e.g., standardize the carbon price assumption).

With those principles in mind, CSCME offers the following alternative approaches for consideration. Both alternatives are based on the notion that while the results of the leakage studies cannot be combined to provide accurate measures of absolute leakage risk, they can be combined to provide an accurate indication of relative leakage risk,

assuming that they are appropriately adjusted for clear deficiencies and standardized to a common carbon price.

8.1 Alternative #1: Use The Results To Confirm Current Leakage Risk Classifications

A “first-best” approach is to use the results of the leakage studies to confirm or disconfirm CARB’s current classification system. In other words, CARB should use the studies to answer the question: did we get it right the first time using far more transparent metrics and a less complex approach? To answer this question, CARB should adjust the domestic output drops calculated under both studies to account for process emissions, standardize those responses to the same carbon price assumption, combine the results, align them with the current leakage risk classifications of each industry, and analyze the results to identify any inconsistencies that might merit closer inspection. This approach could also be used to refine the leakage categories and create more granular “bands” (e.g., very high, high, medium-high, medium, medium-low, low, and very low leakage risk). Specifically, CARB would:

Step 1: Adjust reported output responses for both studies to account for process emissions.

Step 2: Standardize the adjusted output responses for both studies to a single carbon price.

Step 3: Add the (adjusted and standardized) output responses across studies together.

Step 4: Order the combined output responses from highest to lowest.

Step 5: Map those ordered responses to current leakage risk classifications.

Step 6: Identify and analyze inconsistencies between the two sets of results.

8.2 Alternative #2: Use The Results To Calculate Industry-Specific Measures Of Relative Leakage Risk

A “second-best” approach would be to undertake the above methodology but use the results to assign relevant metrics directly (i.e., each industry has its own unique assistance factor, as opposed to being classified in a risk “band”). For example, CARB could adjust the studies’ results to account for process emissions, standardize them to a common carbon price, and add them together to calculate a measure of relative leakage risk that serves as the basis for determining assistance factors for each industry. If left unadjusted, these combined measures would effectively adopt the conservative assumption that each unit of decreased domestic production is displaced by an increase in production outside the state. Alternatively, CARB could adjust the combined

measures to reflect a reasonable substitute for the one-for-one assumption.⁷²² Specifically, CARB would:

Step 1: Adjust reported output responses for both studies to account for process emissions.

Step 2: Standardize the adjusted output responses for both studies to a single carbon price.

Step 3: Combine the (adjusted and standardized) output responses from both studies.

Step 4: Adopt a one-for-one assumption or adjust the combined measures to reflect a reasonable substitute for that assumption.⁷²³ (CSCME)

Response: CSCME provides ideas for alternate applications of the studies in developing assistance factors and suggests exploring a Border Carbon Adjustment (BCA). In the 2nd 15-day notice, staff stated an intent to continue assessment calculations of emissions leakage risk for the post-2020 period, and to propose post-2020 assistance factors in a subsequent rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021 and to consider a BCA. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.13. Comment:

ARB incorporated a regression analysis in the development of both international and domestic assistance factors for the paperboard sector. While the effect was minimal in for the international assistance factor, the regression analysis had a surprisingly significant impact of reducing the domestic assistance factor by more than 25%. ARB states that the purpose of the regression analysis is to "harmonize" the assistance factor component "across different sectors with similar attributes." However, the regression analysis was conducted across all sectors with no attempt to identify sectors that have similar attributes that logically might act in a similar fashion. As members of the paperboard sector, we see no logical reason that our sector should act like or have any relation to the petroleum and natural gas sector, petroleum refining sector, beet sugar sector, coal products manufacturing, wet com milling, fruit and vegetable canning, all dairy product manufacturing, breweries, wineries, turbine and turbine generator manufacturing, aircraft manufacturing, guided missile and space vehicle manufacturing, automobile and other motor vehicle parts manufacturing, and many other covered

⁷²² In the event that CARB adopts a substitute for the one-for-one assumption, we do not recommend that CARB use its current approach to calculating a domestic drop "cut off", which (as explained above) is conceptually incoherent and poorly executed. Rather, we recommend that CARB survey academic literature to identify an alternative assumption that is supported by existing research.

⁷²³ For instance, the combined measure of output responses is likely to be greater than 1.0 for a small number of industries, in which case CARB could cap the assistance factor at 1.0 for those industries and scale the combined measures for the other industries accordingly.

sectors under cap and trade. The attributes in the paperboard sector, including commodity pricing, international competitors, non-California US competitors, energy intensity, and market trends, are vastly different than the other covered sectors under cap and trade. If a regression analysis is to be utilized, it can only be used when similar attributes between sectors are identified, providing rationale for harmonization between like-sectors. No rationale exists today, as ARB has not conducted an effort to identify similar attributes between sectors. As such, there is no rationalization for the 25% drop in the domestic assistance factor for our sector from 0.8 to 0.55. Based on this, we ask that ARB omit the regression analysis from all assistance factor analyses done for the paperboard sector. (GRAPHICPACKAGING)

Comment:

After a great deal of review of ARB's assistance factor analyses and proposed assistance factor for the paperboard sector, we recommend that:...

2. The regression analysis be omitted for the determination of all assistance factors as there is no rationale for or identification of similar attributes between the paperboard sector and any other covered sector under cap and trade. (GRAPHICPACKAGING)

Response: The commenter requests that staff not use the regression approach, as some sectors experienced a reduction in assistance factors under the 2016 methodology. See staff's response to comment B-6.12 for a discussion of the subsequent rulemaking to establish post-2020 assistance factors. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.14. Comment:

Our assessment of the ARB's so-called "demand drop" (DD) methodology for determining the domestic AF revealed a number of issues that render it unreliable in addition to being based on the RFF study results.

1. The \$24.88 per MTCO₂ price used to measure the initial demand (and value-added) drops using the RFF energy price elasticities is far too low. As we understand it, the price represents the 2030 auction price floor, rather than the equilibrium price. Presumably, the ARB projected the floor price into the future because allowances price has not exceeded the floor thus far. However, this was due to the over-allocation of allowances rather than market forces. Since we understand that ARB intends to remove surplus allowances from the market, and due to the increasing demand for California

allowances both from California and from other jurisdictions, there is ample reason to expect the 2030 allowance price would approach and exceed \$40 per MTCO₂.⁷²⁴

2. The regression models the ARB uses to predict the demand drop with 0 AF for each industry sector as a function of its energy intensity fail to explain 77 percent of the variation in output (and similarly, value added) reductions across industry sectors, and the average prediction error is 59 percent. To use a model with such a high prediction error has serious implications for the reliability of the calculated AF.

3. There is no basis for determining the AF in 10 percent increments; there is nothing preventing the ARB from making the determination at 1 percent increments. By the ARB's method, an industry with a 10.2 predicted demand drop (compared to the threshold 10.245 percent) at a 20 percent AF ends up with a 10 percent AF.

4. There is no basis for incorporating value added into the process. Output, specifically physical output, is relevant for emissions—not measures of profit.

As we understand it, the need for the DD methodology is driven by the stringent assumption in the RFF study that all declines in California manufacturing industry output from marginal compliance costs are absorbed by manufacturers in other states. This is not an issue with the FRR study, nor as we understand, with the Hamilton Study. Based on our assessment, the ARB has not cited any prior studies, peer-reviewed or otherwise, using this imputation methodology.

Rather than employ the novel DD methodology that generates and uses weak and imprecise statistical relationships to measure the level of domestic assistance, we recommend that the ARB leverage the resources it has already commissioned and extend the scope of the Hamilton Study to include the California grape processing industry as a means of replacing the results of the RFF domestic emissions leakage study altogether. In addition to allowing for declines in national output, the Hamilton Study overcomes many of the statistical and econometric criticisms of the RFF (and FRR) studies by:

- Measuring the outcome variable as the quantity produced, which has a direct relationship to emissions, and avoids being confounded by contemporaneous, offsetting fluctuations in price and quantity that measure the value-based outcome variables used in RFF and FRR;

⁷²⁴ Lucklow, Patrick, Stanton, Elizabeth A., Fields, Spencer, et al. 2015. 2015 Carbon Dioxide Price Forecast. Available at: <http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast>. Accessed January 20, 2017.

Lucklow, Patrick, Stanton, Elizabeth A., Fields, Spencer, et al. 2016. Spring 2016 Carbon Dioxide Price Forecast. Available at: <http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast>. Accessed January 20, 2017.

ICIS. 2015. ICIS launches 2030 Forecast for California Carbon Allowances. Press Release. January 2015. Available at: <http://www.icis.com/press-releases/icis-launches-2030-forecast-for-california-carbon-allowances/>. Accessed January 20, 2017.

- Using recent firm-specific cost, revenue and energy intensity information; and
- Including sufficient variables describing exogenous factors affecting supply and demand that are specific to the industry/product of interest, allowing for statistical identification of the equation describing the model, and unbiased measurement of energy price elasticities.

(GALLO)

Response: EJ Gallo highlights concerns about the demand drop methodology employed in the 2016 rulemaking. See staff's response to the 45-day comments B-6.3 and B-6.14 for staff's openness to considering additional data in the subsequent rulemaking to establish post-2020 assistance factors. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program. See staff's 45-day response B-6.10 for staff's strong preference not to commission new studies, or extend existing ones.

B-6.15. Comment:

Certain aspects of the ARB's use of FRR 2016 in developing the IMT ignore feasible means of minimizing potential post-2020 emissions leakage. These shortcomings apply broadly, as well as more specifically to the California wine industry. Key among these include

- The ARB's use of the median import and export energy price elasticity ratios in the international AF formula;
- The ARB's use of contemporaneous import and export shares in the post- 2020 international AF formula.

We explain our concern with each of these aspects as they relate to the calculated raw IMT and make recommendations to address them by increasing the international AF for NAICS 312130 based on that factor from 24 to at least 45 percent.

Use of median import and export energy price elasticity ratios

Although measures of central tendency may be appropriate in many contexts, we believe mitigating unintended consequences of environmental policy action require using the upper end of the distribution of metrics describing unintended policy outcomes. By using of the median (50th percentile) estimate for the import and export energy price elasticity ratios, the ARB is only 50 percent confident that it has not underestimated the IMT, and thus the risk of emissions leakage, used to establish the international AF.

Rather than leave the future competitiveness of California industry to a flip of a coin, we recommend that the ARB use the 90th percentile of the distribution. This degree of

conservatism is particularly warranted for our industry, as increasing competition from low-cost grape concentrate producers in South America, for example, is only expected to intensify. During 2010-2014, the value of U.S. wine imports increased more than 5 percent annually, compared to just over 1 percent annual growth in the value of domestic shipments from California.⁷²⁵

Using the 75th percentile of the import and export elasticity ratios reported by FRR 2016, the raw IMT calculated for NAICS 312130 would increase from 24 to 33 percent.⁷²⁶ Using the 90th percentile, as we recommend, would increase the raw IMT above 33 percent.

Use of contemporaneous average import and export shares

There is potential to improve the applicability of the import and export shares in the international AF. Instead of basing their computation on the 2010-2014 average, we recommend that the ARB develop methods to project and extend trends into the post-2020 time period, similar to what it has done with the carbon reserve price (floor price). This can be accomplished through evaluation of historical, industry-specific data, existing forecasts produced by the financial community or other researchers, or through communication with industry representatives. We believe that basing the international AF on import and export shares expected during the time period when the AF will be relevant is more appropriate.

To illustrate the impact of this oversight, we projected import and export trade shares (as calculated by FRR 2016) in the wine industry to 2021-2030 based on the 2010-2014 growth rate. We calculated the raw IMT for 2021-2030 to be 32 percent, based on median energy price elasticity ratios, and 45 percent using the 75th percentile elasticity ratios. (GALLO)

Response: EJ Gallo requests application of an alternate methodology for calculation of the IMT. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking to implement the requirements of AB 398, and have been removed from this rulemaking. See staff's response to 45-day comment B-6.12 for the possibility of using alternate methodologies in the subsequent rulemaking to establish post-2020 assistance factors. EJ Gallo also requests use of future import and export ratios, using extrapolations of current trends. See staff's 45-day response to comments B-6.3 and B-6.12 for staff's openness to

⁷²⁵ ARB 2016. Post-2020 Assistance Factor Calculations Spreadsheet. Available at: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>. Accessed January 14, 2017. Wine Institute. 2016. California Wine Shipments. Available at: <http://www.wineinstitute.org/resources/statistics/article123>. Accessed on January 18, 2017.

⁷²⁶ FRR report the 25th, 50th and 75th percentiles of the distribution of estimated domestic, import and export shipment energy price elasticities derived from estimating 192 different model specifications. ARB has access to the entire distribution and can therefore use the 90th percentile. We reviewed the 'results' worksheet in the file 'post-2020-af.xlsx' to determine the raw IMT using the 75th percentile ratio.

using observed data, but strong preference for avoiding use of future extrapolations of market conditions in informing assistance factors.

B-6.16. Comment:

Energy Intensive Trade Exposure [EITE]:

By the authors' own admissions the academic studies being relied upon by ARB staff contain a number of areas of caution or caveats within the studies. We recommend the Board directs staff to continue to not only work with the researchers but also the regulated industries. These industries have a more comprehensive view of the methodologies and metrics that should be employed rather than the 'apples to oranges' approach the studies have now used. We have the time to refine these studies or develop additional studies. A comprehensive examination of EITE issues must be a priority. Setting and pursuing arbitrary deadlines will only do a disservice to California's economy and the cap---and---trade program.

The difficulty of accurately evaluating the impact of California-only policy vis-à-vis EITE industries is demonstrated in the deficiencies in these studies. Given this uncertainty, policy makers must retain focus on the primary goal, reduced emissions. It is crucial that policies do not place an anti-industry bias above environmental goals.

Further, we must note the ARB staffs' statements in its 'Industry Assistance' workshop of November 7th that 7.5% reduction in any sector output in California was not considered an economic loss and therefore was not a potential for leakage. This statement which largely equates to another great recession, similar to the one that California just weathered, is indicative of a cavalier approach to potential impacts of climate policies on one of the primary sources of jobs in the California economy. (CCPC)

Response: CCPC requests an indefinite extension of 100 percent assistance factors based on concerns with the studies and staff's methodology. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking to implement the requirements of AB 398, and have been removed from this rulemaking. See the response to 45-day comment B-6.1 for the balance between the mandate to prevent emissions leakage to the extent feasible and the costs of over allocation, as well as a discussion of previous allowance allocation accommodations afforded industry during the second and third compliance periods (2015 to 2020). See staff's response to 45-day comment B-6.12 for a discussion of implementation of post-2020 assistance factors in a subsequent rulemaking.

B-6.17. Comment:

6.2 The IMT Rate Is A Conceptually Unsound & Empirically Unreliable Metric

- The IMT Produces Nonsensical Values For Many Industries

The IMT rates are not an output of the International Leakage Study’s modeling exercise. Rather, they are post-hoc calculations that use the study’s modeled results as inputs to a simple arithmetic equation. This practice of calculating the IMT rates “outside the model” using independently estimated elasticities creates the potential for internally inconsistent and illogical results.

According to the data provided by CARB, the calculated IMT rates for several industries are, in fact, inconsistent and illogical. For instance, according to CARB, “IMT is the fraction of every dollar decrease in domestic shipments in response to a marginal GHG price that is offset by an increase in international production (i.e., IMT measures production leakage).”⁷²⁷ Based on this definition, the IMT rates should logically assume values between zero and one. However, the study estimates values below zero and above one for a substantial number of industries.

CARB acknowledges these nonsensical results in its discussion of its methodology for calculating the regressed IMT when it states, “For sectors where raw IMTs were below zero, the raw IMT used in the regression was set equal to zero, and for sectors with raw IMTs exceeding one, the raw IMT used in the regression was set equal to one. Only sectors that were not covered by the program had raw IMTs below zero or above one.”⁷²⁸ However, CARB dismisses these unusual results as irrelevant outliers rather than recognizing that they are, in fact, warning signs that the IMT calculation is a conceptually unsound and empirically unreliable measure of leakage risk.

In addition, CARB fails to fully characterize the extent of the issue, leaving readers with the false impression that these nonsensical values are small in number and magnitude. However, the data provided by CARB suggests that roughly one out of every six industries modeled in the international leakage study have an IMT rate that is less than zero or greater than one, with values ranging from a low of -12.5 to a high of 18.8. Again, such results suggest that the IMT is a conceptually unsound and empirically unreliable measure of leakage risk.

- The IMT Rate Does Not Vary By Carbon Price

A critical flaw of the IMT calculation is that it does not vary by energy intensity or, more generally, the assumed cost increase (see Figure 3). Consequently, it is incapable of accurately capturing leakage risk. This feature is apparent once one rearranges the transfer rate equation presented in the international leakage study as follows:⁷²⁹

$$\text{Transfer Rate} = \frac{|E_{\text{Imp}}| \cdot \text{Imp} + |E_{\text{Exp}}| \cdot \text{Exp}}{|E_{\text{Prod}}| \cdot \text{Prod}} = \left(\frac{|E_{\text{Imp}}|}{|E_{\text{Prod}}|} \right) \left(\frac{\text{Imp}}{\text{Prod}} \right) + \left(\frac{|E_{\text{Exp}}|}{|E_{\text{Prod}}|} \right) \left(\frac{\text{Exp}}{\text{Prod}} \right)$$

⁷²⁷ Attachment B, page 4

⁷²⁸ Attachment B, page 5

⁷²⁹ This arrangement is confirmed by the data dictionary supplied by CARB in the latest release, which expresses the IMT in a similar fashion.

This rearrangement illustrates that an industry's IMT is equal to the product of its "import elasticity ratio" and its historic import trade share plus the product of its "export elasticity ratio" and its historic export trade share. The rearrangement also crystalizes the fact that, by dividing one elasticity estimate by another, the IMT calculation effectively removes the magnitude of the cost increase from consideration. For example, the international leakage study estimates that the cement industry has an import elasticity of 0.88 and a production elasticity of -1.95, which means that a 1 percent increase in costs will result in a 1.95 percent decrease in production and a 0.88 percent increase in imports. This results in an "import elasticity ratio" of 0.45. Likewise, a cost increase of 10 percent would result in a 19.5 percent drop in production and an 8.8 percent increase in imports, which is consistent with an "import elasticity ratio" of 0.45 percent. Simply put, the calculation guarantees (by construction) that an industry's IMT, which CARB purports measures the risk of international leakage, will remain the same, regardless of whether it faces a carbon price of \$1, \$100, or \$1,000.

It stands to reason that an industry's leakage risk will be heavily dependent on the size of the carbon price. All else being equal, a higher carbon price should translate into a higher leakage risk, and vice versa. Given that the IMT does not vary with the magnitude of carbon price, it is incapable of accurately reflecting leakage risk. This fatal conceptual flaw is proof positive that the IMT is unsuitable for policy applications.

- The IMT Is Almost Entirely Dictated by Historical Trade Intensity

Although the IMT rate does not vary by carbon price, it is almost entirely dictated by an industry's historic trade share. Conceptually speaking, this conclusion is evident in the equation above, which illustrates that the IMT is the equivalent of "scaling up" or "scaling down" an industry's trade share by the ratio of elasticities. Empirically speaking, a simple dot plot using the data provided by CARB illustrates that the IMT and trade share metrics are almost perfectly correlated (see Figure 4). This raises important questions about whether the IMT adds any value beyond CARB's current trade share measure, which is far more simple, transparent, and verifiable.

It also raises a more fundamental question about the extent to which an industry's trade share (whether it be expressed in terms of CARB's existing metric or the IMT rates) should even be used to evaluate leakage risk. On the one hand, a high trade share may offer compelling evidence that an industry is already exposed to international competition and, therefore, has limited ability to pass through a carbon price. On the other hand, a low trade share does not mean that an industry is free from international competition and, therefore, has the capacity to pass through a carbon price. In fact, CARB expressed this point of view in its justification of the current allowance allocation

system more than five years ago. Specifically, when discussing the trade share metric, CARB cites a White Paper that concludes.⁷³⁰

“While trade shares may provide a broad indication of carbon-cost pass through potential, in some cases current trade shares may not accurately reflect this. A product that has a low trade share, for example, may not necessarily face barriers to trade or have the capacity to pass through costs, since the imposition of a significant cost could lead to a change in trade patterns.”

In a communication with CARB staff, the authors of the international leakage study express a similar viewpoint, stating that, “a sector could have a steep import supply curve at the margin, but have a large base of imports. On the contrary, another sector could have a potentially responsive import supply curve, with a small competitive base. We would conclude the first sector is more trade exposed using trade shares. However, a careful analysis at the margin would suggest that the second sector is more exposed to leakage.”⁷³¹ In a separate communication with CARB, the same authors state that, “As previous authors have noted, there is no empirical evidence that the trade share metric that CARB is currently using is correlated with/indicative of actual relocation/leakage risk.”⁷³²

Given that it correlates almost perfectly to an industry’s trade share, the IMT does not advance CARB’s efforts to more accurately measure international leakage risk. As a result, CARB’s concerns about using trade share as a proxy for leakage risk remain as valid today as they were when they were expressed before the start of the cap-and-trade program.

- The IMT Is Not Suitable For Public Policy Application

In previous comment letters and discussions with CARB, CSCME has repeatedly pointed out the ways in which the IMT is a deeply flawed concept. The researchers themselves signal this concern in a series of extraordinary qualifications, including:

“Note that these industry-specific transfer rates are constructed as a ratio of our imprecise elasticity estimates. A ratio of noisy numbers can be very noisy; our industryspecific estimates of market transfer rates are sensitive to changes in how the underlying estimating equations are specified.”

“Given the noisiness of these estimates, we cannot estimate the transfer rate for any given industry with any degree of confidence.”

⁷³⁰ Australian Government Department of Environment and Energy 2008 White Paper on the final design of the Carbon Pollution Reduction Scheme, Chapter 12. As cited in CARB Appendix K: Leakage Analysis, p K-17.

⁷³¹ See Exhibit 3.

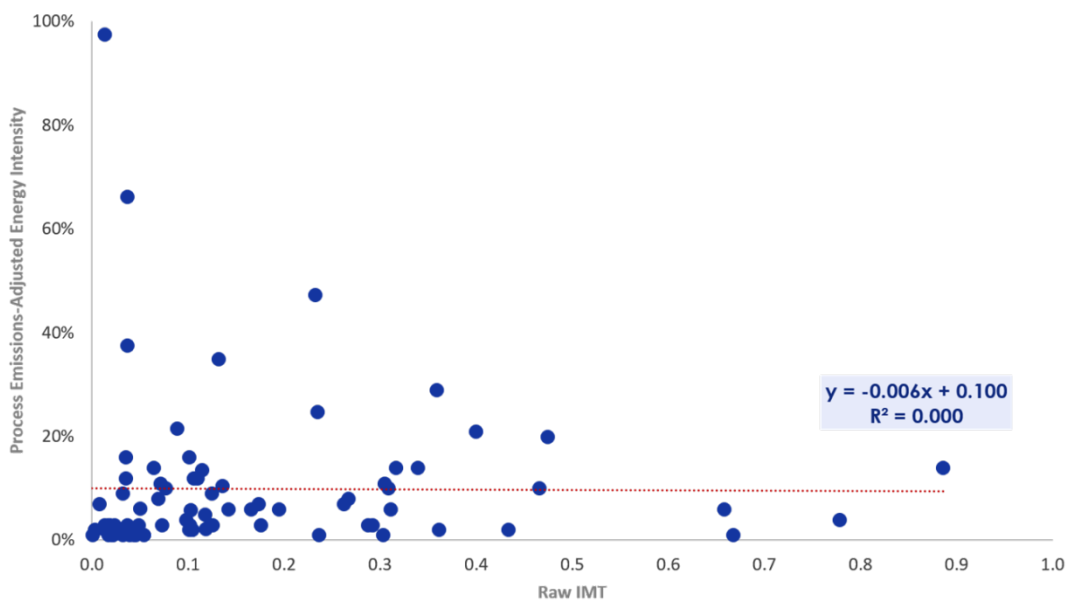
⁷³² See Exhibit 1.

“The imprecision of our estimates make it difficult to estimate leakage potential for any particular industry with any degree of precision.”

To date, CARB has dismissed these extraordinary qualifications. However, as described above, the data provided in the most recent release sheds new light on the conceptual and empirical limitations of the IMT metric, and the researchers’ own reluctance to embrace it as a reliable measure of an industry’s leakage potential.

Given the extensive conceptual and technical deficiencies identified above, CSCME recommends that CARB abandon its use of the IMT metric.

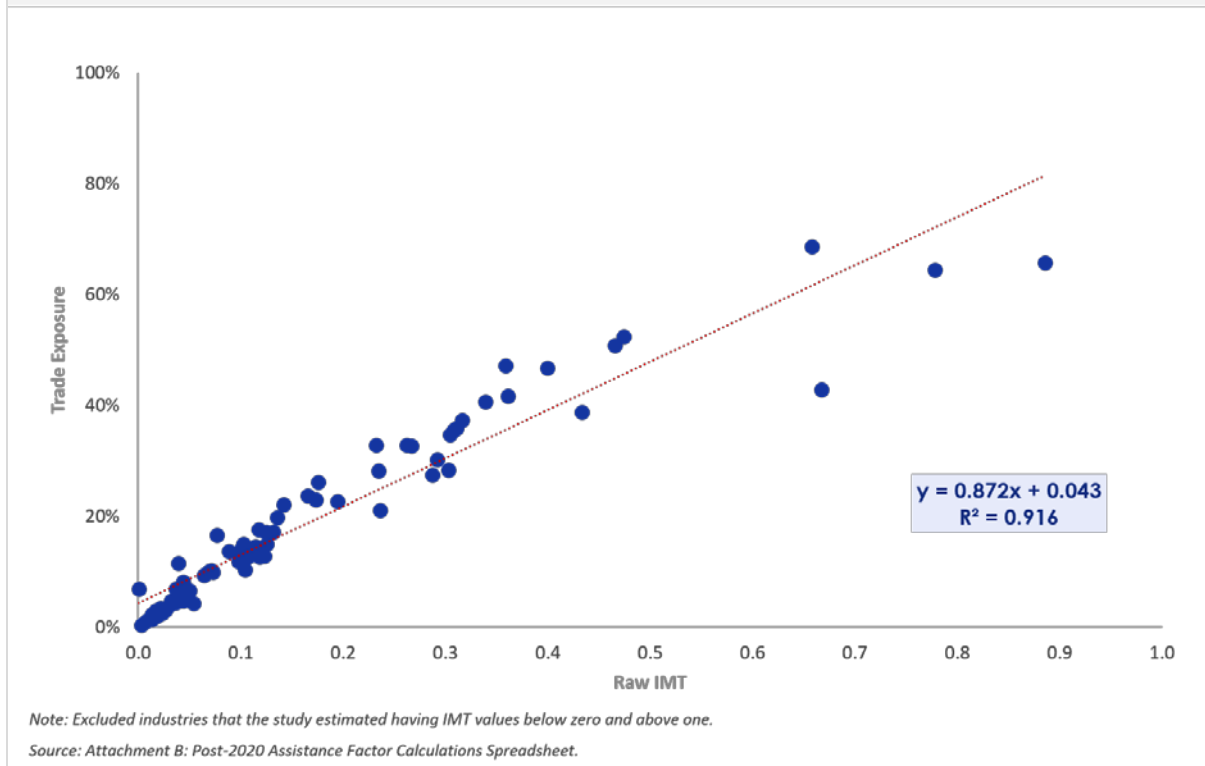
Figure 3: Process Emissions-Adjusted Energy Intensity vs. Raw IMT



Note: Excluded industries that the study estimated having IMT values below zero and above one.

Source: Attachment B: Post-2020 Assistance Factor Calculations Spreadsheet.

Figure 4: Trade Exposure vs. Raw IMT



(CSME)

Response: CSCME highlights concerns with the international market transfer metric. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking to implement the requirements of AB 398, and have been removed from this rulemaking. See staff's 45-day response to comments B-6.7, B-6.8, and B-6.11 for a discussion of the process by which staff will respond to these and other concerns regarding the studies' methodologies during a subsequent rulemaking. See staff's response to the 45-day comment B-6.12 regarding revisions of the study-informed methodology of Appendix E and Attachment B in establishing post-2020 assistance factors.

B-6.18. Comment:

As set forth herein, NAIMA strongly urges CARB to protect the fiber glass industry in the State of California by retaining the 100 percent assistance factors for 2020 and beyond. With respect to the methodologies proposed by CARB, NAIMA makes the following requests, placing great confidence in the statement that "Staff remains open to alternate methodologies that utilize the results from the leakage studies." NAIMA requests that CARB drop the regression methodology from both the international and domestic

components of the fiber glass insulation AF calculation. This would increase the mineral wool manufacturing domestic component from 0.625 to 0.70 (under any method of using the RFF domestic components) and reduce the international component from 0.1121 to 0.11 for a composite AF of 0.81.

NAIMA also suggests that CARB use the maximum value of domestic and international AF values across the alternatives, instead of the average. This would increase the composite fiber insulation AF to 0.821. This approach would demonstrate that CARB is sensitive to its statutory obligations to reduce leakage and is genuinely interested in retaining manufacturing in the State of California...

[The commenter included additional detail which was already reflected in their 45-day comments B-6.11.]

California is losing manufacturing jobs – in both traditional and high-tech industries – to other states and nations. One of the key reasons for this exodus from California is the State's existing regulatory requirements and concerns about the future regulatory climate.⁷³³ NAIMA's members have found California's regulatory environment to be challenging, time-consuming, complex, duplicative, and costly.

CARB's existing Cap-and-Trade Program and now its Proposed Amendments extending the Cap-and-Trade Program beyond 2020 with a specific proposal to ratchet down assistance factors while simultaneously lowering threshold limits is a perfect illustration of such costly regulation. As discussed in greater detail below, the Proposed Amendments afford the fiber glass insulation industry the much needed protection against domestic leakage. NAIMA strongly supports CARB's assignment of 100 percent assistance factors to the fiber glass insulation industry. This is prudent and wise because the California market could potentially be supplied with insulation products by manufacturing facilities in other bordering or nearby states, as well as Canada and Mexico, under the right market conditions...

AB 32 mandates that CARB minimize leakage "to the extent feasible." See California Health and Safety Code § 38562(B)(8). The statutory definition of leakage is not restricted to the international context; rather, it includes any situation where "a reduction in GHG emissions within the state [] is offset by an increase in GHG emissions outside the state." Cal. Health & Safety Code 38505(J). The main body of CARB's "Initial Statement of Reasons" (or "ISOR") for the Cap-and-Trade Program defines leakage in similar terms: "If production shifts outside of California to a region not subject to GHG emissions-reduction requirements, emissions could remain unchanged or even increase."

NAIMA asserts that CARB's Proposed Amendments and revisions to methodology for setting AFs are tantamount to turning its back on its mandate to minimize leakage.

⁷³³ Ross C. Devol, Perry Wong, Armen Bedroussian, Candice Flor Hynek, and David Rice, "Manufacturing 2.0: A More Prosperous California," Milken Institute, June 2009, p. 9.

CARB'S PROPOSED ASSISTANCE FACTOR METHODOLOGY IS SERIOUSLY FLAWED AND WILL RESULT IN LEAKAGE

NAIMA has reviewed CARB's modified assistance factor methodology. Having reviewed and discussed the Proposal, NAIMA and its members still could not with any confidence understand the setting of new assistance factors for the fiber glass insulation industry. Indeed, the original RFF Domestic Study and Berkeley International Study had regression results with unknown statistical properties, making the interpretation of the original results impossible. CARB has further complicated the matter by overlaying additional regressions derived from the initial regression results into an averaging formula to calculate AFs. NAIMA and its members could not understand or comprehend what the results might be and how the results would be reached. CARB has a legal obligation to make their regulations and methodologies comprehensible to the regulated community. When those that are directly and immediately impacted by a regulatory requirement or calculation method that cannot be comprehended by professionals within the regulated industry, it deprives that regulated community of the opportunity to provide meaningful comments. CARB should be required to explain in plain, easy-to-understand language the calculation method. It's like high school algebra – if you don't show your work, you don't get credit.

NAIMA was forced to retain outside assistance (The Brattle Group) in order to try to understand CARB's Proposed Amendments. The Brattle Group described CARB's work as follows: "The entire enterprise results in pseudo-scientific coefficients of unknown and unknowable properties, with extraordinary opaque and intricate derivations that convey a completely false precision that is swamped by an ocean of uncertainty and inaccuracy."

NAIMA requests that CARB seriously consider the following critique from The Brattle Group:

Domestic AF is based on the RFF discussion paper analysis, which attempted to quantify the industry-level expected changes in output (measured in terms of value of shipments, value added and employment) expected from a given change in California energy prices that are unaccompanied by price increases in other states. There were a host of potential problems with the methodology and data, but the resulting coefficients (at least the short-run coefficients) had plausible direction, magnitude and inter-industry patterns. RFF also showed how one parameter (value added) would vary given a \$22.62 per metric ton carbon price (\$2009) and different levels (in percent deciles) of assistance factor (Table A-1 in the RFF study).⁷³⁴ In Table A-1, short-term (one year) changes in value added under a \$22.62 per ton carbon price that increased natural gas and electricity costs for NAICS 327993 (Mineral Wool Manufacturing) varied from - 22.8% without any assistance to -2.6% if allowances compensated for 90% of the

⁷³⁴ The \$22.62 in 2009 dollars equates to \$24.88 in 2016 dollars (see p. 14 12/21 document)

production cost increase. The RFF researchers did not report statistical measures of significance with the results.

In a series of documents, ARB staff has proposed a methodology to convert the RFF findings into the Domestic Assistance Factor (AF) component of the overall AF measure. This method has no obvious basis in theory and does not reflect a conceptual approach other than reducing the range of AFs through a process of reducing higher AFs and increasing lower AFs as estimated by RFF findings. The process has several distinct steps:

First, in the October 21, 2016 document, ARB reproduced the RFF Table A-1 on Value Added as Table 3 and provided the counterpart table for Output (actually value of shipments) from the RFF analysis as Table 4.

Second, ARB designed a method to provide two additional tables, by running regressions that took some of the results of the RFF analysis and augmented them with industry energy intensity data. ARB provides no theoretical foundation for using this technique, in fact the method of using regression-derived coefficients (reduction in value added or sales under a \$24.88 allowance price) as data for subsequent regressions seems entirely ad hoc. Nevertheless, both the intent of these regressions and subsequent results of Tables 5 and 6 (reductions in value added and sales revenue across different levels of AF based on the regressions) is to raise the AFs for sectors with low AFs and reduce the sectors with high AFs, without regard to whether those shifts represent further minimization of leakage.

Third, ARB posits a threshold of acceptable declines in output, namely 7 percent, based on an analysis of representative annual declines in output across the sectors (see p. 14-15 12/21 document). ARB also scales this 7% factor to 8.954% to account for different price years (the ratio of 2030 to 2025 auction reserve price used in the SRIA analysis).

Fourth, ARB applies this threshold to the four different AF factor “demand drop” tables (Tables 3-6 10/21 Document) and for each industry (row) finds the decile assistance factor that corresponds to a demand drop that just exceeds the threshold applied (8.964%) and then use the next highest decile. This is nominally conservative, insofar as they do not interpolate but use the highest decile. On row NAICS 327933 (Mineral Wool) in Table 3, for example, the 8.964% drop lies between that estimated for the 60% Assistance Factor (-10.2) and the 70% Assistance Factor (7.7) so the 70% factor is used for that row.

Fifth, ARB averages out the 4 decile levels selected to produce the Domestic Assistance Factor. Note that in the August 2, 2016 Document ARB originally intended to use the maximum decile level obtained by applying the threshold to the four demand drop tables, not the average (see pp. 15-17). This change lowers the final calculated value of the domestic AF, and I do not find any discussion for the change in methodology in later documents.

Aside from the weaknesses in the RFF study itself, the two primary flaws in ARB translation of the RFF study findings into domestic AFs are the addition of regressions (which serve only to increase low AFs and lower high AFs as found in the RFF study) and the application of a uniform threshold across industries (and the basis for the level of the threshold).

Additional Regressions

The regressions are a good example of analysis run amok. They are initially motivated by the observation that RFF found that some industries had positive coefficients (where the expected coefficients were negative) and those tended to be industries with low energy intensity. However, only 5 out of 49 industries actually had positive coefficients in the output or value added analyses, i.e., they were distinct outliers, and may have been statistically indistinguishable from zero in any case. So, instead of simply assuming that this implied no domestic leakage risk (e.g., setting the domestic AF = 0) ARB invented a methodology to give them a small AF, a methodology that begins with the step of setting them to zero! The technique that ARB designed to boost the AFs of these outliers (and other industries with near-zero estimated elasticities) also by construction *lowered* the AFs for industries that tended to have higher energy intensities, which [is] unnecessary and completely unmotivated by any theory.

A far more natural way to treat these outliers – especially since the RFF study did not provide any metrics that could help determine if they were statistically distinguishable from zero – would have been to simply ignore them and set them at zero for purposes of determining a domestic AF. Instead, the ARB technique introduces another layer of unknown statistical properties onto an already-suspect set of results and thereby reduces AFs for the most energy intensive industries. But there is no rationale for this leveling of assistance factors from the standpoint of minimizing leakage, which is inherently discriminatory across industries that have varying degrees of vulnerability. That some sectors get zero assistance factors while others get 100% may in fact be the most efficient allocation of allowances to minimize leakage.

The Uniform Threshold for Leakage

Another leveling technique arises in the ARB use of a uniform threshold cutoff for leakage (e.g., 7%). It is worth noting that the motivation for that threshold is completely contradictory to the underlying estimation methodology; the RFF regression coefficients theoretically hold other causes of output decline constant:

This section describes how we use the estimated coefficients from our main statistical analysis to simulate the short- and long-run effects of imposing a GHG compliance cost on California plants in the estimation sample....Importantly for the simulations, the regressions include year-fixed effects, which hold fixed national output, value added, and employment. Therefore, in the simulations, we hold these outcomes fixed at their actual levels in 2009. That is, the simulations allow us to characterize the extent to which a GHG compliance cost only on California plants may cause manufacturing

activity to shift from California to other states, under the assumption that national activity is unaffected.⁷³⁵

The rationale for adopting 7% as a cutoff is incomprehensible. Apparently, it represents a representative “bad” year-on-year changes in all industrial output. But, since the RFF regressions presumably isolate the impact of leakage only, this implicitly suggests that ARB believes that 7% reduction in output is acceptable level of leakage. How that squares with the AB32 direction “to minimize leakage to the extent feasible” is never explained, nor is any theoretical or conceptual basis offered. It’s just an average drop in industrial output attributed to reasons that have nothing to do with leakage, and thus is completely arbitrary.

International Assistance Factor

ARB conducts a similar extension of the Berkeley International Analysis, namely creating an alternative “regression” IMT (International Market Transfer) coefficient based on altering outlier coefficients and then using the original coefficients as data in other regressions that used sectoral data on energy intensity and trade exposure. Again, no genuine motivation is offered except citing some stakeholder concerns about the validity of industry level findings – and a desire to homogenize outcomes to reduce the inter-industry range of IMT values.

As in the case with domestic AFs, the additional of international regression IMTs (which ARB takes as equivalent to the international component of AF) serve to increase the AF of sectors with low AFs and decrease the AF of sectors with higher AFs. As in the domestic AF analysis, the preferred approach would be to scrap the ARB regressions all together, and simply use the results of the Berkeley study.

NAIMA’S RECOMMENDATIONS

NAIMA strongly urges CARB to protect the fiber glass industry in the State of California by retaining the 100 percent assistance factors for 2020 and beyond. The opaque and impenetrable calculations and regressions undertaken by Staff serve only to produce a false precision that is in the end not helpful to the issue of identifying and quantifying real leakage risk. Instead, Staff is reminded to consider important “real world” issues such as the multiple fiber glass manufacturing plants on California’s border and in nearby states, which consideration requires no complicated statistical analysis but merely examination of a map and the understanding that fiber glass insulation manufacturing production capacity is still well below 100 percent. With respect to the methodologies proposed by CARB, NAIMA makes the following requests, placing great confidence in the statement that “Staff remains open to alternate methodologies that utilize the results from the leakage studies.” NAIMA requests CARB drop the regression methodology from both the international and domestic components of the AF

⁷³⁵ RFF Study p. 15.

calculation. This would increase the mineral wool manufacturing domestic component from 0.625 to 0.70 (under any method of using the RFF domestic components) and reduce the international component from 0.1121 to 0.11 for a composite AF of 0.81.

NAIMA also suggests that CARB use the maximum value of domestic and international AF values across the alternatives, instead of the average. This would increase the composite fiber insulation AF to 0.821. This approach would demonstrate that CARB is sensitive to its statutory obligations to reduce leakage and is genuinely interested in retaining manufacturing in the State of California...

NAIMA strongly urges CARB to honor its statutory mandate to minimize leakage. The gradual ratcheting down of assistance factors will force NAIMA's companies to seriously contemplate closing California plants. The calculation method cannot be easily understood, and that results in limited confidence as to what the future holds. NAIMA asks that CARB retain 100 percent assistance factors for the fiber glass industry. In the alternative, NAIMA recommends that CARB drop the regression methodology from both the international and domestic components of the assistance factor calculation. As noted above, this will increase the likelihood that NAIMA's companies could continue to operate in California. NAIMA also requests CARB use the maximum value of domestic and international assistance factors instead of the average, across the alternatives. NAIMA is genuinely concerned about regulations and calculation methods so complicated and complex that assistance outside the industry had to be retained and, upon retaining that assistance, discovered that the expert found the calculation methods confusing and loaded with extraordinarily "opaque and intricate derivations that convey a completely false precision that is swamped by an ocean of uncertainty and inaccuracy." NAIMA will seek a face-to-face meeting with CARB to further address these issues and petition for clarity and feasibility. (NAIMA)

Response: NAIMA raises a number of concerns with the studies. Staff deferred the establishment of post-2020 assistance factors until a subsequent rulemaking to give stakeholders, including NAIMA, a greater chance to provide input on the post-2020 assistance factors. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program. See staff's 45-day response to comment B-6.3, B-6.13, B-6.14 and B-6.23 for a discussion of consideration of other methodologies, agreement on the importance of preventing domestic emissions leakage, and encouragement for NAIMA's and other stakeholders' participation in a subsequent rulemaking to establish post-2020 assistance factors. See staff's response to 45-day comment B-6.10, and first 15-day comment B-6.12 for our strong preference to ground potential methodologies in existing data and previously-commissioned studies.

Third Compliance Period Assistance Factors

B-6.19. Comment:

Assistance Factor for 2018-2020

In recognition of the potential for emissions leakage, Assembly Bill 32 compels ARB to minimize leakage “to the extent feasible” in its operation of the cap-and-trade program. Consequently, and in order to facilitate the transition to emissions pricing, ARB has freely distributed emissions allowances to covered entities according to their production levels and leakage risks. ARB presently infers leakage risk from calculations of industry-specific emissions intensity and trade exposure.

In “Appendix E: Emission Leakage Analysis,” released August 2, 2016, ARB staff states that no changes are proposed to the 45-day regulatory proposal for the third compliance period.⁷³⁶ In joint comments by Ag Council and the Agricultural Energy Consumers Association on September 19, 2016, we stated that providing 100 percent free allowances would minimize the potential harm to the agricultural sector and avoid simply shifting emission to other locations outside of California. In response to stakeholder comments, staff responded in the December 21, 2016 Notice of Public Availability and Modified Text Document:

“In response to the 45-day regulatory proposal, some stakeholders requested that ARB modify third compliance period assistance factors to retain the 100 percent assistance factors for sectors in the medium and low leakage risk categorizations. These stakeholders argue that these sectors are at high risk of leakage and therefore require 100 percent allocation to prevent emissions leakage. These requested changes are outside of the scope of the current regulatory changes, as the 45-day regulatory proposal did not address assistance factors for those sectors during the third compliance period. Therefore, no changes to those assistance factors are being proposed within this rulemaking package. Further, leakage analyses performed for the initial Regulation in 2010/2011 and those performed for the current regulatory changes demonstrate that all sectors currently in the medium- and low-leakage risk categorizations do not require 100 percent allocation to protect them from emissions leakage. The assistance factors proposed for the post-2020 period (Table 8-3 of this 15-day proposal) demonstrate that the third compliance period assistance factors are either at the level needed to prevent against emissions leakage or they are higher than needed.”⁷³⁷

In Section 95870 of the Modified Regulation, Table 8-1 is adjusted to include new leakage risk categorizations and assistance factors.⁷³⁸ For example, Wet Corn Milling was determined to have high leakage risk and was assigned a 100 percent third

⁷³⁶ <https://www.arb.ca.gov/regact/2016/capandtrade16/appe.pdf> (page 3)

⁷³⁷ <https://www.arb.ca.gov/regact/2016/capandtrade16/15daynotice.pdf> (page 15)

⁷³⁸ <https://www.arb.ca.gov/regact/2016/capandtrade16/attacha.pdf> (page 157)

compliance period assistance factor. We understand this change was included in the Modified Regulation because it was identified in the scope of the 45-day regulatory proposal. However, we disagree with the assertion that all sectors currently in the medium leakage do not require 100 percent allocation in the third compliance period. As stated in our November 4, 2016 comment letter, the main reason ARB commissioned additional research on leakage was because there were doubts that ARB had correctly measured the energy intensive and trade exposed nature of our members.⁷³⁹ In previous comment letters we have continued to ask ARB to conduct more analysis and advocate that the food processing sector should be moved to the top Industry Assistance Factor tier of “high” and receive 100 percent free allowances due to price pressures from domestic and international markets. Given the previous examples of the peach industry import pressures, coupled with the already existing problems of California dairies leaving the state, leakage has been demonstrated within California agriculture due to the competitive disadvantages we are experiencing in our current regulatory environment. This impending cap-and-trade regulation is bound to exacerbate this issue, as we are the only state in the nation with this law.

Having a reliable and stable supply of safe, high quality, and affordable domestic supply of food should be a public policy priority. California produces food in the most environmentally sound, socially conscious state in the nation. ARB should protect our food supply by reducing the cost of this regulation to the best of its ability. Furthermore, food processors are economic drivers in many disadvantaged communities across the state. For these reasons ARB should designate food processors as high risk for leakage. (AGCOUNCIL)

Comment:

High Leakage Risk for 3rd Compliance Period

ARB staff’s position is that any changes to 3rd compliance period assistance factors (extending 100% allowance allocation in the 3rd compliance period) is beyond the scope of this rulemaking.

While adherence to procedure may bar changes to this regulation in the present proceeding, it is not a bar to such adjustment. Moreover, it does not dismiss the fact that facilities have been pressing ARB on this issue since before it was determined that the state would likely meet the goal of AB 32 and reduce emission to 1990 levels, and possibly below.

ARB has ignored stakeholders’ repeated requests to revisit the third compliance period allocation factors. Furthermore, these actions do not reconcile with AB 32’s requirement that:

⁷³⁹ <https://www.arb.ca.gov/lists/com-attach/29-ct-amendments-ws-VGYBN11tWD1SeQk4.pdf> (page 2)

(h) The state board shall update its plan for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions at least once every five years. (Assembly Bill 32, Chap. 488, Stats. 2006) emphasis added.

Reductions to 1990 levels was the goal and that goal is expected to be achieved. Barring any unforeseen increases in emissions from industrial sources, adherence to systematic reductions in industry assistance provides no additional benefit in the form of either necessary reductions or leakage prevention.

ARB should, at the earliest possible opportunity, commence a rulemaking that will seriously consider the extension of 100% allocation allowance in the 3rd compliance period. (FOODPROCESSORS)

Response: Ag Council and CLFP request an extension of 100 percent assistance factors. This request is out of scope for the current rulemaking, as those provisions related to the third compliance period were not amended as part of this rulemaking. Staff agrees that minimizing emissions leakage resulting from Cap-and-Trade is an important goal, and an AB 32 mandate. Staff disagrees that 100 percent assistance factors are necessary to prevent emissions leakage during the 2018 to 2020 period for medium and low leakage risk sectors. See staff's 45-day response to comment B-6.1 for the importance of avoiding unnecessary allocation and the tangible benefits that arise from reducing industrial assistance to medium and low leakage risk sectors in CP3. See also response to 45-day comment B-6.1 for previous accommodations that have already been afforded industry in the 2015 to 2020 timeframe to assist medium and low leakage risk industries adjust to operating with a carbon price signal, and the reasons staff did not open 2018–2020 assistance factors to adjustment as part of the scope of the 2016 rulemaking. See response to 45-day comment B-6.24 for staff's belief that eight years' advance notice of adjustment in allocation for medium and low leakage risk sectors' assistance factors afforded these industries ample time with which to prepare for reduced allocation. See response to 45-day comment B-6.4 that specifically addresses a request from CLFP for 100 percent assistance factors for food processing sectors in the third compliance period.

B-6.20. Comment:

Table 8-1 on page 161 of the revised Cap and Trade Regulation incorrectly shows NAICS code 325194 in the Medium Leakage Risk Category with an Assistance Factor of 75% for the Third Compliance Period. Both the 15-Day Notice text (p. 14) and Table 5 of Attachment B show NAICS in the High Leakage Risk Category with an Assistance Factor of 100% for the Third Compliance Period. This should be corrected in the second 15-day regulatory package. (ONDAENERGY)

Response: CP Kelco notes a discrepancy between the first 15-day notice's intent to designate NAICS 325194 as a high leakage risk sector under the

existing methodology, and its placement in Table 8-1 of Attachment A to the first 15-day notice. Staff thanks CP Kelco for their comment. This error was corrected in the second 15-day regulatory change proposal. See the second 15-day notice section I for a discussion of the emissions leakage analysis (i.e., trade exposure and emissions intensity evaluation) that was conducted to support the 100 percent assistance factors for the four industrial sectors (including NAICS 325194) that had previously unestablished assistance factors, so were open for establishment of 2018-2020 assistance factors during this rulemaking.

B-6.21. Comment:

In the current proposed rulemaking, CARB has proposed to include Windset's facility under the North American Industry Classification System (NAICS) code 111419: "Other Food Crops Grown Under Cover." This NAICS code is proposed to be designated a medium leakage risk and would be assigned an assistance factor of 75% for the third compliance period of the cap and trade program. Windset has some concerns about the method used to calculate the leakage risk for our facility. Both the emissions intensity and trade exposure calculations would be improved with some refinement in the data. The emissions intensity data has been changing for our facility over time and we would be pleased to provide additional data for use in determining an appropriate factor.

Regarding trade exposure, the data used by CARB from the United States Department of Agriculture (USDA) also appears to under-report sales data for our sector of the agricultural industry. In this area, Windset plans to provide additional industry data for use in CARB's calculations. (WINDSET)

Response: See responses to 45-day comments B-6.3 and B-6.14 for our willingness to use current or historical industry data as appropriate in informing the assistance factors that are within scope of a rulemaking. Staff communicated with Windset before and during the 2016 rulemaking in establishing an appropriate assistance factor for emissions leakage prevention. After receiving this comment, we expressed openness to reviewing the information referenced in this first 15-day comment in advance of potential changes during the second 15-day package. Windset did not provide the data in advance of the release of the second 15-day package, so we were unable to use it in informing the 2016 rulemaking. See also response to second 15-day comment B-5.3.

Industry-Specific Comments on Assistance Factors

B-6.22. Multiple Comments:

Based on our assessment, we believe there is room for significant improvement in the approach for determining the post-2020 AF. We believe that the proposed AF does not sufficiently account for leakage risk, especially given the competitiveness of the domestic and international markets for wine and spirits, concentrate and related

products classified in 6-digit NAICS 312130 (wine industry). Our proposed recommendations would increase the international AF, (based on the raw international market transfer (IMT), from 24 to greater than 45 percent, and support a path toward quantifying a reliable estimate of domestic AF for the California wine industry. (GALLO)

Comment:

The potential sources of domestic emissions leakage for wine, spirits and grape fruit concentrate include wineries operating in Washington, New York, Oregon and Pennsylvania. Although grapes are produced in almost all states, these are the major wine producing states other than California and the most likely to absorb domestic market transfer. Since the wineries in these states are not operating in a carbon-constrained market, they are not subject to the same increased costs as California wineries.

The potential sources of international emissions leakage for wine, spirits and grape fruit concentrate are wineries operating in France, Italy, Australia, Chile, Argentina, New Zealand and Spain. These are the major sources of imports (by value) of product classified under NAICS code 312130. Similar to the challenges of domestic carbon leakage, these entities are not operating in a carbon-constrained market.⁷⁴⁰ As California wine becomes less competitive both domestically and internationally due to the increased costs associated with cap-and-trade, there is the potential that we will lose market share to entities in non-capped regions with higher emissions. (GALLO)

Comment:

Based on our assessment, both the international (FRR 2016) and domestic emissions leakage risk studies (RFF 2016) have statistical and econometric modeling issues that, to our knowledge, have not been addressed. As summarized in a June 10, 2016 letter to Chairman Nichols from Dr. Armando Levy of The Brattle Group, these issues have significant implications for the reliability of the estimated energy price elasticities and marginal compliance cost impacts the ARB uses to determine industry-specific AFs.⁷⁴¹

In light of these and other issues, the authors of both studies caveat interpreting elasticities for individual industries, and their ability to measure the effect of California-specific cap-and-trade regulation. Instead, the authors conclude their models demonstrate that leakage risk increases with energy intensity and trade exposure. This conclusion validates the ARB's approach to determining AFs for the previous compliance periods, rather than improves the reliability of emissions leakage risk measures for the post-2020 time period. Despite the authors' caveats, the ARB is using the studies for exactly this purpose. We suspect that this is leading to major omissions,

⁷⁴⁰ United States Department of Commerce, International Trade Commission. Foreign Trade Data Statistical Program U.S. International Trade Statistics. 2016. Value of Exports, General Imports, and Imports for Consumption by (NAICS - 312130) Wines. Accessible at: https://censtats.census.gov/naic3_6/naics3_6.shtml.

⁷⁴¹ Armando Levy, Ph.D.. Letter to Chair Nichols dated June 10,2016.

however, we cannot validate this since the study datasets were not made available to other researchers and the regulated community. Furthermore, RFF 2016, which purports to be an econometric study, does not even publish the standard model summary statistics that scientists use to evaluate the reliability of statistically estimated parameters and the degree to which the model can quantify associations between the variable of interest and the variable(s) thought to influence it.

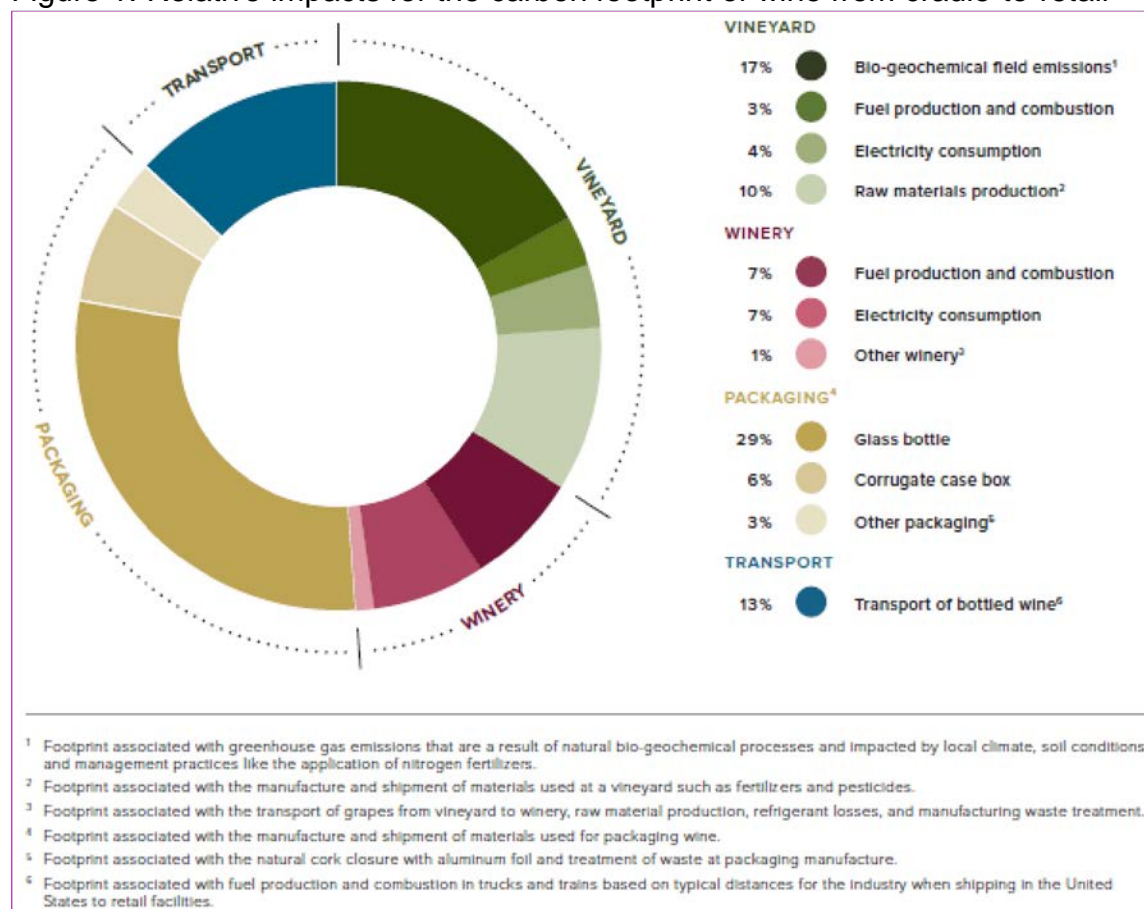
In addition to the statistical and econometric modeling issues highlighted by Dr. Levy, other issues affect the reliability of the industry-specific energy price elasticities, and marginal compliance cost impacts on which they are based. These include basis on extended historical data back to 1993 (FRR 2016) and 1991 (RFF 2016) terminating in 2011 (FRR 2016) and 2009 (RFF 2016), prior to major inflection points in wine industry competition. In addition, the apparent need for a one-size-fits-all industries approach means that the modeling assumptions and specifications are generalized across industries, and that its structure prevents analysis of the full extent of expected compliance costs.

Regarding the latter, the models attempt to measure the reduction in economic output *within individual industries* using changes in relative energy prices between California and the unregulated of region acting as a reference, fails to capture the effect of energy price inflation on the cost of non-energy productive inputs purchased from other industries. As a result, given the complexity of our product, wine has a carbon price applied to intermediate products at multiple points along the supply chain.

Specifically, our wine products experience the effect of carbon prices at the vineyard, winery, and packaging stages. In addition, both the winery and packaging stages are directly covered at our Gallo Glass and Fresno facilities. As Figure 1 demonstrates, the AFs are accounting for 14% (Fresno) and 29% (Gallo Glass) of our emissions in isolation instead of considering the impact of the embedded and compounding cap-and-trade costs from both of these facilities and across the entire value chain. This is in contrast to a product like cement, which does not have intermediary products covered by the cap-and-trade program and is just capped at the cement manufacturing facility.

Therefore, for a product like wine with many intermediary products, the leakage risk and by extension the AF is under projected.

Figure 1: Relative impacts for the carbon footprint of wine from cradle-to-retail



Source: California Sustainable Winegrowing Alliance (CSWA).⁷⁴²

Whether the authors intended for these effects to be captured through simulated carbon price floors is unclear, and irrelevant, given that the price impacts manifest as incremental energy costs in both studies. This omission has potentially significant implications for the reliability of the industry-specific AFs. From our perspective, our operations will face higher costs of glass bottles and grapes which are not accounted for in the modeled energy price elasticities. The higher costs of these inputs will significantly increase our overall product costs and by extension, reduce our profitability.

- **Glass Containers.** Our Modesto, California facility produces glass bottles for our winery operations. Glass container manufacturing (NAICS code 327213) is relatively energy intensive and both studies conclude there would be substantial market transfer, even from the mere \$10 per MTCO₂ carbon price floor they consider. Purchasing glass bottles from third-parties, should it be necessary, would be done at a premium relative to our operations.

⁷⁴² CSWA. 2011. US / California Wine's Carbon Footprint. Available at: http://www.sustainablegrowing.org/docs/California_Wine_Executive_Summary.pdf. Accessed January 18, 2017.

- *Grapes.* Fruit is a significant portion of the cost of producing wine, concentrate and related products derived from grapes. While individual vineyards are not subject to AB 32, the regulation will nonetheless raise the cost of production to all vineyards, regardless of ownership or contracting relationship, that consume electricity to power machinery such as groundwater pumps.

Given the potential significance of non-energy compliance costs, we recommend that the ARB determine a method for its quantification and build it into estimates of emissions leakage risk measured by energy price elasticities, or otherwise develop a means for incorporating the impact in the AF determination formula. (GALLO)

Comment:

Long Term Implications

Finally, upon the receipt of the new assistance factors, we plugged these numbers into our cap-and-trade model. What we saw was a steep drop off in free allowances starting in 2020 for our Fresno, California facility. To develop a pathway forward, we have begun to explore options to reduce emissions to drop our footprint below 25,000 MTCO₂e through either efficiency or decreased production so that we might opt out of the California Cap-and-trade program. In the case of the latter, the California Cap-and-trade would have curtailed our output because we cannot pass along the marginal costs of the program into all of our products, or to consumers in all segments of a given product market. Ultimately, we believe that reducing output goes against the overall intent of the Cap-and-trade program and hope that we can work towards a mutually acceptable solution. (GALLO)

Response: EJ Gallo highlights concerns they have with the fit of the studies to its current experience of the markets in which it competes. See response to 45-day comment B-6.3 for our openness to receiving industry data as input to a subsequent rulemaking to establish post-2020 assistance factors. See staff's responses to comments B-6.6 and B-6.7 for staff's plan to incorporate EJ Gallo's and other stakeholders' input into a subsequent rulemaking to establish post-2020 assistance factors. It is also important to note that with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.23. Comment:

UPI takes its environmental stewardship responsibilities very seriously, and supports ARB's efforts to implement environmentally and economically sensible mechanisms for controlling greenhouse gas (GHG) emissions. UPI believes, however, that ARB's proposed decrease in the post-2020 Industry Assistance Factors will unduly burden UPI and other California manufacturers, and that it will greatly enhance the potential for

“GHG leakage.” This is an important consideration that ARB should not underestimate...

Lack of Adequate Basis for Decrease in Industry Assistance Factors

ARB’s proposed amendments are based on the results of two leakage studies⁷⁴³ that are not sufficiently rigorous to support such a sudden and drastic reduction in Industry Assistance Factors post-2020. As UPI pointed out in its Comments on the Cap-and-Trade Regulation Amendments Workshop in November 2016,⁷⁴⁴ these studies are inconclusive at best and, therefore, should not form the basis for such a risky and economically burdensome policy.

This issue is further exacerbated by the high degree of uncertainty surrounding the federal Clean Power Plan (CPP). Andrew Campbell, of the Energy Institute at Haas,⁷⁴⁵ emphasized the importance of considering leakage when undertaking unilateral policy development such as California’s Cap-and-Trade program, specifically referencing the potential impact of the demise of the CPP. The proposed substantial decrease to Industry Assistance Factors, including those UPI Comments on Proposed Amendment to Cap-and-Trade Regulation for the Rolled Steel Shape Manufacturing Sector, would reduce support for California’s already-fragile industrial businesses while increasing the risk of higher GHG emissions from production moved elsewhere – thus providing economic benefit to less environmentally responsible areas.

UPI Proposal

As UPI stated in its November comments, UPI supports a more measured decrease to Industry Assistance Factors,⁷⁴⁶ such as the decrease that will take place from the second compliance period (2015-2017) to the third compliance period (2018-2020). Further, UPI can only support decreasing the Industry Assistance Factors for the Rolled Steel Shape Manufacturing Sector to a percentage level that is conclusively determined, through robust analysis, to promote both the environmental objectives of the Cap-and-Trade program and the sustainability of California industry. (POSCOINDUSTRIES)

⁷⁴³ Measuring Leakage Risk, Fowlie, et al, May 2016, <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/ucb-intl-leakage.pdf>; and Employment and Output Leakage under California’s Cap-and-Trade Program, Gray et al, May 2016, <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/rff-domestic-leakage.pdf>.

⁷⁴⁴ Comments of USS-POSCO Industries, Cap-and-Trade Regulation Amendments Workshop, pgs. 1-2, <https://www.arb.ca.gov/lists/com-attach/47-ct-amendments-ws-UTJUPQdrBTsKaQNT.pdf> (submitted November 4, 2016). Also see, California Council for Environmental and Economic Balance Comments on October 21, 2016 MRR and Cap-and-Trade Regulation Workshop, pg. 4, <https://www.arb.ca.gov/lists/com-attach/60-ct-amendments-ws-Am9TJ1UmBQIQNwVr.pdf> (submitted November 4, 2016); and Climate Change Policy Coalition Comments on California Air Resources Board’s Consideration of the Proposed Amendments to the Cap-and-Trade Regulation, pgs. 2-3, <https://www.arb.ca.gov/lists/com-attach/65-ct-amendments-ws-BWYBZF0sVmYHXgJh.pdf> (submitted November 4, 2016).

⁷⁴⁵ <https://energyathaas.wordpress.com/2017/01/09/risks-of-going-it-alone/>

⁷⁴⁶ Comments of USS-POSCO Industries, Cap-and-Trade Regulation Amendments Workshop, pg. 2.

Response: U.S.S. POSCO Industries believes that the reductions in assistance factor proposed for the post-2020 period are premature and, if done, should be further analyzed before implementation. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking to implement the requirements of AB 398, and have been removed from this rulemaking. See staff's response to comment B-6.12 for the process that will inform a subsequent rulemaking to establish post-2020 assistance factors.

B-6.24. Comment:

Coke Calcining

95871 Table 8-3 - Assistance Factors (AF) by Industrial Activity

Tesoro believes that there are fundamental flaws in the new methodology that CARB is applying to determine industry assistance across all sectors and agrees with WSPA's comments on this subject. Notwithstanding this fundamental methodological concern, Tesoro believes that important data has been overlooked within the method CARB has proposed as follows:

We believe that ARB has significantly understated trade exposure risk for coke calcining (NAICS code 324199). The domestic AF component is understated because of the energy intensity of calcining, the high percentage of self-produced fuel, and the high emission factor associated with self-produced fuel. In 2013, BP sold the calcining facility to Tesoro, but had provided information to CARB about its operation. We ask that you review Tesoro's letter to ARB dated January 29, 2014 relative to the parameters used to calculate the domestic AF component (provided directly to staff for business confidentiality reasons).

Because the census data utilized by ARB failed to capture the high level of exports for petroleum coke, the international AF component is also understated. A 2013 report titled Petroleum Coke: Industry and Environmental Issues by the Congressional Research Service (<http://www.nam.org/CRSreport/>) documents that about 80% of US petroleum coke is exported. As a point of reference, Tesoro exports virtually all of its calcined coke.

Tesoro would be pleased to work closely with ARB to supply additional information to insure that the assistance factor for calcining is maintained at the current level of 100% beyond 2020. (TESORO)

Response: Tesoro indicates that staff's assumptions regarding energy intensity and trade exposure do not match CBI and Congressional Research Service information on the calcining industry. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking to implement the requirements of AB 398, and have been removed from this rulemaking. See also response to 45-day

comments B-6.3 and B-6.14 for our openness to considering verifiable industry information in informing a subsequent rulemaking to establish post-2020 assistance factors.

B-6.25. Comment:

These changes are quite alarming for CSI. A main component in the formula for GHG allocations - the Assistance Factor - will be drastically reduced in the case of hot rolled, cold rolled, pickled, and galvanized steel sheet production (NAICS Code 331221). As we understand it, this will result in a drastic reduction of the credits we are allocated; which means that, post- year 2020, CSI's Cap & Trade liability will be significantly increased and could prove untenable for us.

On average, CSI received 193,828 GHG credit allocations per year during the first four years of the AB32 program. Based on the information contained in Attachment B of the proposed amendments released on December 21, 2016, CSI would only receive about 34,000 GHG credit allocations per year, post 2020. This amount is estimated to cover less than 15% of CSI's projected future annual GHG emissions.

As you are aware, no one knows the future cost of GHG credits. However, as an example, at just \$20 per ton of GHG credit, assuming no increase in steel production, the increased annual purchase requirement for CSI will cost approximately \$3.3 million per year. These cost increases will reduce CSI's ability to grow our business, to create and retain good jobs, to provide pay increases and profit sharing to our employee team members, and to supply excellent employee benefits.

The California Manufacturers & Technology Association (CMTA) has previously submitted comments regarding Industry concerns of the ARB studies that were used as a basis for the Staff Report. These studies were noted as flawed. In CSI's case, the studies and the Staff Report do not take into consideration the unique nature of CSI's business and the global competition/situation that 'makes or breaks' our business and the company's ability to remain competitive.

The proposed Assistance Factor reduction will result in CSI's competitiveness being severely threatened as we will be the only hot rolled steel sheet facility in the U.S. facing tens of millions of dollars of new compliance costs in coming years, for what is ostensibly a global climate change "demonstration" effort. Our foreign competitors in China and other nations, as well as our domestic competitors, will be happy to undercut our costs and take away our business, if they can. We are at high risk for losses to these competitors as we endure unique, CSI-only, regulatory costs, which no other steel sheet rolling operation must bear.

The Assistance Factor reduction especially disadvantages CSI against in-state competitors. Unlike CSI, our steel sheet competitors in California have no hot rolling capability. They use hot rolled sheet from other states and nations as their feedstock to produce cold rolled and galvanized sheet, which competes with CSI's similar products.

Their hot rolled sheet feedstock will not be burdened with these additional costs. Since we produce our own hot rolled sheet in California, and use that as our feedstock for cold rolled and galvanized product, our costs will be increased even in comparison to our in-state sheet competitors.

Furthermore, any resulting loss of CSI's steel production will simply be replaced by less efficient production in other states and other nations. This will be accompanied by additional shipping distances, resulting in greater truck and rail emissions. Altogether, this means increases, not decreases, in global GHG emissions, and an accompanying decrease in steel manufacturing jobs and associated supply chain jobs in California.

The proposed cuts in Industry Assistance are unfair from another standpoint -- there are no existing technologies available to make any significant decrease in GHG emissions from natural gas-fired furnaces such as used in the hot rolling process.

In 2012, the U.S. EPA published Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry and Greenhouse Emissions the Iron and Steel Industry. It is important to note that this report shed no light on any reasonably available, highly effective technologies. The study lists 11 recommendations for energy efficiency measures that are specific to Hot Rolling Mills; 9 of these measures are currently employed in CSI's Hot Rolling Mill.

CSI, as a long-standing producer in California, is easily among the most efficient steel rolling operations in the U.S., if not the world. We have already implemented many technologies for energy efficiency and will continue to do so, regardless of ARB's final stance. These efforts have enabled CSI to reduce its GHG per ton of steel so that it is at 60% of 1990 levels. Additionally, we have spent millions of dollars on emission controls of various types not typically employed elsewhere in the world. However, these technologies typically address only indirect GHG and/or particulate emissions, with no effect on our direct GHG emissions, which are based solely on natural gas consumption.

There is simply little that we can do to further reduce direct GHG process emissions except cut production of rolled steel, and that will only allow our out-of-state competitors the opportunity to take advantage of our situation by producing more steel elsewhere for sale to our California and western U.S. customers.

Finally, CSI already pays one of the highest electricity rates in the global steel industry, due in large part to the strong portfolio of renewable energy we use, as mandated for public utilities in California. We have great incentive to use energy efficiently; and daresay, there is no "greener" steel sheet production facility in the United States. This is another reason why regulatory policies should be assisting us to stay in business and grow and prosper in California - rather than placing steel production and related jobs under undue cost pressure, with highly questionable effectiveness at lowering global GHG emissions.

OUR REQUEST

Regretfully, the position taken by ARB on CSI's post-2020 Industry Assistance Factor is unbalanced and is injurious to the environment and the economy in the Golden State. We hope to work with you to correct these potentially devastating impacts. California needs the 1,000, well-paying, middle-class jobs that we provide, as well as those of our numerous California vendors and customers.

Ideally, CSI's hot rolled steel production should be exempt from the obligation to purchase GHG emission credits in the cap and trade auctions. This would level the playing field with CSI's competitors, in-state and out-of-state. At a minimum, the level of CSI's allocations, post 2020, should be kept at the same level as the pre-2020 allocations. Additional information is attached on CSI and its exposure to competition from outside California....

[The commenter submitted a PowerPoint document that states that imported steel products are gaining market share as consumption in the Western US decreases. The document also states that in its hot rolling manufacturing process CSI has adopted 9 of the 11 energy efficiency best practices as outlined by a 2012 EPA Iron and Steel Industry White Paper.⁷⁴⁷ The following text is excerpted from the summary slide of the commenter's PowerPoint document:]

CSI's Position on Cap and Trade

- Energy intensive and trade exposed
- Unique among California steel firms
- West's only producer of hot rolled steel sheet
- 100% exposed to leakage
- World-class in energy efficiency and GHG emissions
- Prepared to grow good jobs in California

We ask ARB to reconsider its position on reducing industry assistance post 2020.
(CALSTEELIND)

Response: CSI comments that it has already deployed most available measures to improve GHG efficiency in its hot rolled steel production, and that without continued allowance allocation at a level higher than that proposed for steel production under the 1st 15-day assistance factors, its increased compliance obligation would result in emissions leakage. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation will be

⁷⁴⁷ Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry. <https://www.epa.gov/sites/production/files/2015-12/documents/ironsteel.pdf>

considered as part of a future rulemaking and have been removed from this rulemaking. See response to 45-day comments B-6.3 and B-6.14 regarding considering verifiable industry information in informing a subsequent rulemaking to establish post-2020 assistance factors. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.26. Comment:

- First, we continue to request the California Air Resources Board's (ARB) consideration of adjusting the food processing industry assistance factor to reflect high leakage and provide 100 percent allocation in the third compliance period.
- Second, we strongly oppose the ARB proposed post-2020 approach to allowance allocation that uses the non-peer reviewed results of two academic studies and continues to categorize food processing in the medium leakage category.

Post-2020 Industry Assistance Factor Calculations

In contemplating leakage mitigation efforts beyond 2020, ARB directed staff to "investigate potential improvements" to its system of allowance allocation in order to better minimize leakage. Appropriate allocation of emission allowances is critical to ARB's mandate to minimize leakage and, indeed, to the success of California's climate-change program. The determination of leakage potential across industries and of mitigation measures is essential for the effective implementation of additional regional climate-change policies.

As ARB considers both the third compliance period and post-2020 assistance factors for food processing, it is important to note that this industry has historically been influenced by not only supply, but also with the opportunities for cost-efficient processing. Food processing facilities have been built in locations where market access is conducive to lower manufacturing and shipping costs. Conversely, product supplies have moved and expanded to meet the processing capacities of those facilities. Equipment in one plant can be moved to a new location to serve another more lucrative market.

As with other California industries now regulated under cap-and-trade, food processing was built to meet domestic and international demand. Export markets have grown to meet California's product output. As we have stated in earlier comments, domestic and international markets are dynamic and volatile, driven by competitiveness in product price. Product prices are based upon costs.

The importance of accuracy in the calculation of assistance factors, before or post-2020 cannot be overstated. Calculations applied to the food processing sector should be

enhanced by readily available data. For example, the California Department of Food and Agriculture compiles useful data in its annual manufacturing cost study for dairy. For comparison and determination of emissions leakage, a variety of cost comparisons can be made using a variety of comparable cost information for other dairy manufacturing regions within the United States. Recognizing that the product mix is not uniform across domestic manufacturers, this cost data would give the fuller picture of the California dairy industry and its competitive placement against domestic dairy product manufacturers.

In Attachment B of the Modified Regulation, staff proposes a framework whereby percent assistance factors will be assigned for each manufacturing industry by summing an international leakage mitigation assistance factor based upon the University of California Berkeley study⁷⁴⁸ and a domestic leakage mitigation assistance factor based upon the Resources for the Future study.⁷⁴⁹ Currently, staff is not proposing to use the data from the CalPoly San Luis Obispo food processing leakage study.⁷⁵⁰ Staff states in Attachment B that they, “appreciate the difficulty of obtaining results given limited aggregated data of these food processing industries,” and that staff, “will continue to evaluate the potential to incorporate the study into development of AF s for these four sectors.”⁷⁵¹ Substantial public sector funds were spent to support this study and after many years of research, we urge ARB to revisit and review its findings. If the study was updated, it will likely demonstrate the inability to pass on the cost of this program in the food processing industry. (AGCOUNCIL)

Comment:

From the onset of the Cap-and-Trade (“C&T”) program, ARB provided for an allowance allocation methodology that designated food production sector facilities as “medium” leakage risk, whereby granting the food industry free allocation assistance factors of 75 percent through the 20182020 compliance period. In 2011, ARB directed staff to investigate and recommend potential improvements to the industrial allowance allocation to better meet the objectives of the establishing legislation (AB 32) by looking for ways to minimize leakage from domestic (California) industries to the extent feasible.

As part of this directive, ARB commissioned three independent studies that utilize different methodology to answer the larger question of the potential leakage risk associated with recalculating the assistance factors for the C&T program. Although specifically commissioned by ARB, staff is only proposing to use two of the three studies to develop assistance factor methodology post 2020. We find this approach to

⁷⁴⁸ <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/ucb-intl-leakage.pdf>

⁷⁴⁹ <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/rff-domestic-leakage.pdf>

⁷⁵⁰ <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/calpoly-food-process-leakage.pdf>

⁷⁵¹ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachb.pdf> (page 17)

be problematic, as we do not believe the two relied upon studies accurately represent emission leakage risk, which is the intent of the ARB's directive.

At their core, the two utilized studies, Gray et al. (domestic study)⁷⁵² and Fowlie et al. (international study)⁷⁵³, fail to accurately assess genuine industry specific emissions, the principal reason for ARB commissioning these studies. We cannot support ARB moving forward with the Staff Proposal for assistance factors when the relied upon calculation methodology utilizes results from studies that are incompatible with industry specifics – especially the food industry – and that do not accurately measure emissions leakage for California entities. Some of the more pressing issues we have with the two utilized studies are highlighted below:

- There is no mention of a comparison between California emission control efficiencies versus international emission control efficiencies or other states' control efficiencies. Without comparing the emission controls between industries outside of California, ARB cannot possibly quantify emissions leakage.
- The authors of the two studies acknowledge that they based their conclusions on insufficient statistical data, whereby making it impossible to accurately predict direct leakage risk to California based entities. The authors in the domestic study (*Gray et al.*) acknowledge the study's limitations to predict long-term effects of a carbon price to any degree of certainty; and the international study (*Fowlie et al.*) recognizes that quantifying production leakage rate to international markets solely from California is difficult due to the limited data set available. This fact required the authors to simulate how such a transfer rate may appear, rather than making calculated projections.
- The studies do not adequately represent the leakage risk between California and neighboring US states. The study by Fowlie et al. only compares California to international markets, and the Gray et al. study is focused on how additional carbon prices (emission credits) will affect California industries.
- The food processing industry is a unique category of emitters and should be specifically studied to provide adequate projections as to the impacts of decreased assistance factors post 2020. ARB staff are not proposing to use the data from the third leakage study by *Hamilton et al.*⁷⁵⁴ which specifically looks at data from the agricultural sector, because staff believes that study was too

⁷⁵² Gray, W., Linn, J., and Morgenstern, R. (2016). *Employment and Output Leakage under California's Cap-and-Trade Program*. Accessed 11/4/16:

<http://www.arb.ca.gov/cc/capandtrade/meetings/20160518/rff-domesticleakage.pdf>

⁷⁵³ Fowlie, M., Reguant, M., and Ryan, S. (2016). *Measuring Leakage Risk*. Accessed 11/4/16

<http://www.arb.ca.gov/cc/cap-and-trade/meetings/20160518/ucb-intl-leakage.pdf>

⁷⁵⁴ Hamilton, S.F., Ligon, E., Shafran, A., Villas-Boas, S. (2016). *Production and Emissions Leakage from California's Cap-and-Trade Program in Food Processing Industries: Case Study of Tomato, Sugar, Wet Corn and Cheese Markets*. Orfalea College of Business, Ca Poly San Luis Obispo. Accessed 11/4/16:

<http://www.arb.ca.gov/cc/capandtrade/meetings/20160518/calpoly-food-process-leakage.pdf>

conservative. We do not agree with ARB's assessment of this study and support ARB reevaluating the conclusions derived from the *Hamilton et al* research.

The aforementioned deficiencies in the two studies are outstanding. We believe it would be counterintuitive and inappropriate for ARB to develop long-term (post 2020) program elements based on studies wherein the authors acknowledge their own limitations to predict long-term effects to any degree of certainty. It would be fundamentally flawed for ARB to use any assumption in place of a fully vetted study for emission control comparison. The intent of AB 32 is to reduce California Greenhouse Gas ("GHG") emissions, and in turn, reduce global GHG emissions, since California as an individual state is a large contributor. However, there is no value in reducing California emissions if that would lead to an increase in GHG emissions elsewhere in the globe as GHG emissions reside in the atmosphere *globally*. In fact, without adequate quantification of industry specific emissions efficiencies between California and non-California facilities, there is no guarantee that production leakage from California (no matter how small) will not generate an overall increase in global GHG emissions. (WONDERFUL)

Response: Ag Council requests an extension to 100 percent assistance factors, and use of the Hamilton study for four food processing sectors. Wonderful requests use of the Hamilton study and expresses related concerns regarding leakage. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation for leakage prevention would be considered as part of a future rulemaking, and have been removed from this rulemaking. See response to 45-day comment B-6.3 regarding considering industry data in the subsequent rulemaking to establish post-2020 assistance factors. See response to 45-day comment B-6.19 for staff's reasons in not extending the 100 percent assistance factors for food processors to the 2018 to 2020 period. See response to 45-day comment B-6.10 for staff's preference not to extend current studies, or commission new studies as requested by the Ag Council's comment. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.27. Comment:

We believe that a properly designed Cap-and-Trade program can be a cost effective means of achieving emissions reductions, and we generally support the extension of a Cap-and-Trade program post-2020 as opposed to new command and control regulatory schemes. We also generally support the approach for the post-2020 industrial assistance factors, but we believe product-specific analysis and coordination with individual industrial sectors is still needed before the ARB releases a final 15-day

rulemaking package. Praxair looks forward to working with the ARB to evaluate and refine a post-2020 Cap-and-Trade program.

DISCUSSION

The Domestic Leakage Risk Analysis Should Account for Leakage Risks Across the United States and Different Products Within a Single NAICS Code.

The allowance allocation scheme is one of the most important aspects of the Cap-and-Trade program that must be carefully developed in order to reflect the diversity of products, processes and services in California's economy. Praxair supports the ARB's efforts to address domestic leakage risks faced by Emissions Intensive Trade Exposed ("EITE") industries, and we commend the ARB and its economists for taking an important first step in developing a domestic leakage methodology in Appendix E to the Proposed Amendments. In order to develop an accurate emissions leakage risk analysis, we believe two refinements or clarifications are needed.

First, as we have noted in our previous comments, the analysis should cast a sufficiently large net to account for the fact that some products are exposed to leakage risks in the mid-west and eastern United States. After the May 18th leakage risk workshop, we expressed concern with the proposed 500 mile radius assumption.⁷⁵⁵ Industries like the liquefied hydrogen sector, which are highly electricity intensive, have a relatively small group of competitors, and whose products can easily be shipped across the country, face trade risks from production throughout the United States. The ARB should update the analysis or make clear that domestic trade risk was evaluated throughout the United States, and not just from neighboring states.

Second, the ARB should evaluate potential updates to the EITE assistance factor tables to reflect the various products that may be reported under a single NAICS code. It is not clear from the categorization of certain products within a six digit NAICS code were distinguished from one another (i.e., those industries with more than one product benchmark in Table 9-1). The liquefied hydrogen sector can face a greater different domestic leakage risk than other types of industrial gas production, and it is not clear from Appendix E how the ARB distinguished liquefied hydrogen from other types of industrial gas production. Praxair is concerned that the new assistance factors for liquefied hydrogen may not fully account for the unique aspects of liquefied hydrogen. (PRAXAIR)

Response: Praxair asserts that the domestic study's methodology may not recognize features unique to the liquid hydrogen industry. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking, and have been removed from this rulemaking. See responses to the 45-day comments B-6.3

⁷⁵⁵ See Praxair June 10, 2016 comments on May 18, 2016 ARB Staff Workshop (p. 2), available at: <https://www.arb.ca.gov/lists/com-attach/15-ctleakagestudies-ws-BTRcbFRIVzJXYFJi.pdf>

and B-6.14 for the process by which we will consider data and additional stakeholder input into a subsequent rulemaking to establish post-2020 assistance factors. See response to 45-day comment B-6.10 for our strong preference not to commission additional leakage analysis nor to extend existing external leakage analysis, but to use the current leakage analysis as well as current or historical data available at the time of the subsequent rulemaking. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.28. Comment:

The California glass container manufacturing industry request our industry's post-2020 industry assistance reflect our "high-leakage" status and be retained at 100% of our current allocated credits. Reducing the allocation to 81% will have a significant and potentially devastating production impact on the four remaining California facilities.

As explained in comments submitted in 2016, and below, to CARB, California's container glass container manufacturing industry competes directly with out of state and international glass plants. In fact, GPI has advocated since 2011, that the Cap-and-Trade program puts facilities that operate in the state under constant competitive pressures and costs that other facilities operating throughout North America do not face. Further, providing a 100% assistance factor to the glass container manufacturing industry does not in any way jeopardize the state's GHG reduction goals, or give industry a free pass on compliance.

University of California, Berkeley Report:

In the final report to CARB issued in May 2016 Final Report to CARB on Employment and Output Leakage under California's Cap-and-Trade Program, on page 16, clearly states that no EITE industry participant is impacted more by leakage than the glass container manufacturing industry, anticipated to lose significantly in terms of output (17.10%) and jobs (13.31%). Further, the report made the following conclusion about the impact on industries who operate and purchase energy in the state: *"an increase in California energy prices relative to prices in nearby regions will raise production costs in energy-intensive industries located in California and likely result in short-term (one year) losses in output, employment, and value added for those industries."*

Industry is Trade Exposed:

Without certain considerations around the industries benchmark and use of cullet, California glass container manufacturing companies will continue to be affected in a disproportionate manner. Leveling the playing field should be the goal for any climate policy. However, simply adding additional regulatory compliance costs to manufacturers in California may lead to further market erosion to competition outside the State. These

include: continued erosion of containers made in-state, quickened market erosion to alternative packaging materials, increased imported product (food and wine and food and wine packaging) from China, product shift to jurisdictions throughout North America where electricity costs less and is more reliable.

The Census Data tab in the CARB issued *Post-2020 Assistance Factor Calculations Spreadsheet* shows a trade exposure rate of 23.1%. However, this calculation's latest data is from 2012. As outlined below, trade exposure for the California glass container industry is much higher.

According to data collected by the US International Trade Commission (ITC) 2.1 billion additional containers were imported into the US in 2015, then in 2008. Nationally, imports of glass containers have increased 3-5% annually since 2008. Further collected data culled from the U.S. Census Bureau, Datamyne ® and internal company estimates the following:

Annual growth rate for imports over 10 years is 14%; including the most recent five years' growth at 13%, with no signs of slowing.

In 2015, China surpassed Mexico for most overall glass food and beverage container imports (now accounting for 32% of all imports).

Imports account for a significant share of the California glass container supply (28% in California, versus 13% nationally).

The value of glass containers imported into California has doubled between 2009-2015 from \$210 million to \$510 million.

In 2015, 81% of all imported glass wine bottles from China came in through the ports of San Francisco, Los Angeles and Seattle. These West Coast ports are the top three in terms of all glass food and beverage packaging points of entry.

In fact, for the first 6 months of 2016, 47% of all imported glass wine bottles came from China.

California glass container manufacturing represents 20% of the total US glass container demand.

The number of imports of 12-ounce glass bottles have increased 16.5% since 2011.

Additional Carbon Credits Purchased

In order to ensure productivity from the four facilities remains constant, the California glass container manufacturing industry, collectively, has purchased 277,933 carbon credits since 2014, at a cost of just over \$3.8 million dollars.

These purchases reflect further financial investment in the Cap and Trade program, and clearly demonstrate that the glass container manufacturing industry does not have a "free pass" in terms of compliance obligations.

In conclusion, taking into consideration of the unique, increasing and competitive pressures facing the California glass container manufacturing industry, we request that our industry's credit allocation remain at 100% of the current allocated amounts and the industry's early action credits also remain an important part of the benchmark.

[The commenter attached a table of production data from California glass facilities.]
(GLASSPACKAGING)

Response: The Glass Packaging Institute asserts that the domestic studies indicate that their members' production is highly impacted by carbon compliance obligations, and that recent trends have resulted in a higher trade exposure than that measured by the studies. Staff agrees that the studies indicate that in the absence of allowance allocation, the glass industry would experience a significant reduction in output and value added.⁷⁵⁶ The studies, and other information sources and stakeholder participation, can inform a subsequent stakeholder process to establish post-2020 assistance factors. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking and have been removed from this rulemaking. See responses to 45-day comments B-6.3 and B-6.14 regarding consideration of additional high-quality industry information during this stakeholder process. It is also important to note that with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Regarding the GPI's members not having a "free pass," staff agrees that the sector's compliance obligation exceeding allowance allocation indicates the sector is not over-allocated. Having a compliance obligation that exceeds allocation, however, does not guarantee that the compliance obligation strikes the appropriate balance between emissions leakage prevention and allocating allowance value for other important uses (i.e., ratepayer protection: see response to 45-day comment B-6.1 for some of the reasons to avoid over allocation).

Staff is encouraged that the glass industry has already undertaken steps to increase GHG efficiency in the first two compliance periods. The necessary amount of allowance allocation to minimize leakage can be close to, or less than, the total allowances resulting from production of the sector's product. The former represents the levels of allowances received by GPI's member companies due to GPI members' high leakage risk designation and previous efforts to increase GHG efficiency, whereas lower levels of allowance allocation will be received by medium and low leakage risk sectors starting for the 2018 compliance year.

⁷⁵⁶ The quoted section of the report comes from the RFF domestic study, not the international study.

B-6.29. Comment:

Overall, CMTA believes that a well-designed cap and trade is the most cost-effective method for achieving GHG emissions reductions while limiting the impact to California's economy. Enabling companies to choose the most economical method for reducing emissions will limit the negative effects of imposing the compliance costs on California manufacturers when no other competitive market also imposes such costs on their manufacturers.

While CMTA believes that the overall concept of a market-based mechanism is an appropriate and necessary alternative, there remains several key issues in the draft regulations that must be addressed prior to approval.

Insufficient Industry Assistance Risks Leakage

AB 32 required the ARB seek to limit leakage of emissions out of California in its implementation of GHG reduction regulations, including the market-based mechanism. As a part of the program, ARB initially allocated 90 percent of necessary allowances to meet compliance obligations to ensure that the regulations did not result in emissions leakage, also known as the loss of emissions to other jurisdictions. ARB later extended the initial allowance allocation into the second compliance period to maintain leakage protection.

CMTA appreciates that ARB backed off an earlier plan to reduce allowance allocation in the Third Compliance Period (2018-2020) as this would have placed California manufacturers in a very awkward and challenging spot. However, it is troubling to see that ARB staff would propose massive reductions across numerous industry sectors for the post-2020 period. With some sectors facing reductions in industry assistance to as little as three percent, the risk of leakage becomes unacceptable.

It is important to note that this is not necessary to meet California's AB 32 (2006) goals or those established under SB 32 (2016).

CMTA believes that given the significant economic impact represented by the allowance allocation process demands that ARB maintain the current allowance allocation through 2020 and beyond.

Maintain Industry Assistance at 100 percent

CMTA continues to recommend that ARB maintain industry assistance at 90 percent through the Third Compliance Period and post-2020 for all industry sectors. This change would delete the planned drops for medium and low leakage risk categories to 75 and 50-percent and beyond resulting in greater protection against emission leakage and job loss.

California manufacturers support the development of a well-designed cap and trade program to provide a cost-effective mechanism for reducing GHG emissions. (CMTA)

Response: See staff's response to the 45-day comment B-6.1 for the reasons staff believes medium and low leakage risk industries can adjust to lower assistance factors starting with vintage 2018 allocation, as well as staff's previous accommodations for stakeholder concerns for the reduction in allocation. See staff's response to the 45-day comment B-6.29 for staff's mandate to minimize emissions leakage to the extent feasible as specifically related to the Cap-and-Trade Program. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking, and have been removed from this rulemaking. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.30. Comment:

The world's largest borate producers are located in California and Turkey, followed to a much lesser extent located in Argentina, Chile, Bolivia, Peru, Russia and China. While the United States remains a net exporter of borates, U.S. Borax has lost 40 percent of its global share of refined borate sales over the last two decades due to higher labor, energy and regulatory costs of doing business in California. And, in the U.S. alone, imports of borates, primarily on the east coast, have increased in recent years due to the favorable cost position of Turkish borates over borate products from California. The Turkish borate producer, a government owned company without any mandatory climate change requirements, has recently taken a more aggressive approach in the West, directly threatening California producers' positions both in California and in the Western US markets.

The Proposed Assistance Factor for Borate Mining and Manufacturing Does Not Reflect the Risk of Leakage Faced by California Borate Producers and Needs to Be Adjusted Upward.

Consistent with the direction of the Global Warming Solutions Act of 2006, in developing the Cap-and-Trade Regulation, the Board recognized it would need to take steps to minimize the risk of leakage as a result of imposing a carbon price on energy intensive / trade exposed industries operating in California. The Board, in the Cap-and-Trade Regulation, rightly classified U.S. Borax, which reports its greenhouse gas emissions under NAICS Code 212391 (potash, borate and soda ash mineral mining), is at a high risk of leakage and assigned an Assistance Factor ("AF") of 100% for each year 2013 through 2020.⁷⁵⁷ However, despite the increasing competition U.S. Borax faces for its borate products in domestic and international markets, the 15-Day Amendment Text assigns borate mining and manufacturing an Assistance Factor of 63%. Borate mining and manufacturing must be assigned an AF of 100% to appropriately reflect the leakage

⁷⁵⁷ Cal. Code Regs. tit. 17, § 95871, Table 8-1 (March 2016).

risk faced by California borate producers. Anything less than an AF of 100% will adversely affect the ability of California borate producers to compete against international companies whose borate products do not include a carbon cost and will increase the risk of leakage...

2. The Board Needs to Adjust the Assistance Factor Assigned to Borate Mining and Manufacturing to Reflect the Highly Competitive Global Market for Borate Products.

While U.S. Borax supports staff's recommendation to separate borate mining and manufacturing from soda ash mining and manufacturing for purposes of industry assistance, the 63% Assistance Factor proposed for borate mining and manufacturing in the 15-Day Amendment Text fails to account for the international competition faced by California borate producers. Attachment B to the 15-Day Amendment Text indicates that staff assigned a domestic AF of 0.60 to both the mining and manufacturing of borates and mining and manufacturing of soda ash.⁷⁵⁸

U.S. Borax agrees that a domestic AF of 0.60 for the entire 212391 sector is appropriate. However, an international AF of 0.03 was assigned to the mining and manufacturing of borates subsector (versus a 0.53 international AF assigned to the mining and manufacturing of soda ash subsector).⁷⁵⁹ Staff did not study the 212391 sector.

Staff states in Attachment B that for non-studied sectors in the mining industry, such as soda ash, diatomite and rare earths, U.S. Geological Survey subsector-specific trade exposure information was used to calculate the international AF component. Staff also notes "[a]s part of the amendment process, staff is reviewing whether or not it is possible to conduct a similar sub-sector trade exposure analysis for borate production."⁷⁶⁰

U.S. Borax strongly supports staff's intention to review trade exposure information for borate mining and manufacturing. However, because global borate production is dominated by two companies – U.S. Borax and the government-owned borate producer in Turkey – all sales and pricing data is closely held to protect each companies' competitive position vis-a-vie each other and the handful of other smaller borate producers. Accordingly, unlike other mining and manufacturing sectors in California, the U.S. Geological Survey does not have the trade exposure information needed by staff.

In December 2016, U.S. Borax met with Board staff to share the information necessary to analyze the trade exposure of California borate producers. This information included

⁷⁵⁸ 15-Day Amendment Text, Attachment B, Post-2020 Industry Assistance Factor Calculations at p.30 (Dec. 21, 2016).

⁷⁵⁹ Ibid.

⁷⁶⁰ Ibid. at p.18.

the value of domestic U.S. shipments of borate products, the value of U.S. exports of borate products and the value of U.S. imports of borate products. The information provided by U.S. Borax is all Confidential Business Information consistent with the confidentiality provisions of the Cap-and-Trade Regulation⁷⁶¹ and the California Public Records Act.⁷⁶² U.S. Borax believes the information it has provided to staff supports assigning an international AF to borate mining and manufacturing of 0.50 or greater. U.S. Borax will continue to work with staff so that the Board has all the information it needs to analyze the trade exposure for borate production and establish an international AF component that accurately reflects the global competition, and corresponding price sensitivity, for borate products. (USBORAX)

Response: U.S. Borax requests that staff consider industry-specific CBI at the sub six-digit NAICS level for NAICS 212391. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking and have been removed from this rulemaking. See response to 45-day comment B-6.3 for staff's openness to receiving industry-specific data. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.31. Comment:

1. Distinguishing Borate Mining and Manufacturing from Soda Ash Borate Mining and Manufacturing is Appropriate for Purposes of Allowance Allocation.

In the Cap-and-Trade Regulation, the Board identifies a single Assistance Factor for all covered entities reporting their greenhouse gas emissions under NAICS Code 212391 – potash, borate and soda ash mineral mining. In Table 8-3 of the 15-Day Amendment Text, which sets forth the Assistance Factors for industry sectors eligible for an allowance allocation for the year 2021 and beyond, staff proposes splitting the 212391 sector into two separate subsectors: “Mining and Manufacturing of Borates” and “Mining and Manufacturing of Soda Ash.”⁷⁶³ U.S. Borax supports staff's proposal and would urge the Board to adopt an amended Cap-and-Trade Regulation which distinguishes between borate mining and manufacturing and soda ash mining and manufacturing. (USBORAX)

Response: U.S. Borax requests that, for the purposes of assistance factor calculation and where justified by industry-specific data, staff assess leakage risk at higher levels of refinement than the 6-digit NAICS level. See staff's

⁷⁶¹ Cal. Code Regs. §96021.

⁷⁶² Cal. Govt Code §§ 6250 et seq. (2016).

⁷⁶³ 15-Day Amendment Text § 95871, Table 8.3 (Dec. 21, 2016).

response to 45-day comments B-6.32 and B-6.12. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Miscellaneous

B-6.32. Comment:

The ARB Should Evaluate EITE Designations for Industries that are Trade Exposed Solely Due to Their Electricity Consumption.

The current regulation only includes EITE designations for industries that exceeded the Cap-and-Trade threshold (25,000 MTCO₂(e)/year). The ARB should broaden its analysis to account for sectors that may not have significant direct, on-site GHG emissions, but are high users of electricity. As utilities pass through GHG costs in electricity rates, this will create risks of trade exposure for these “electricity-intensive industries.” Consistent with the ARB’s statutory requirements to “minimize leakage” in the design of its regulations (Cal. Health and Safety Code Sec. 38562(b)(8)), the ARB should endeavor to evaluate new EITE designations for these electricity-intensive industries. (PRAXAIR)

Response: Praxair requests that staff extend analysis of emissions leakage risk to include industrial facilities below the 25,000 MTCO₂e a year threshold that consume large amounts of electricity. ARB does not have a regulatory relationship with the vast majority of these electricity consumers, and indeed does not know the scope of these non-covered facilities. As the agency with oversight of EDU IOUs and their industrial electricity consumers, including under the SB 1018 requirement to distribution EDU IOUs’ allocation allowance auction proceeds to emissions-intensive, trade-exposed industries, CPUC would be the agency most qualified to provide this analysis.

B-6.33. Comment:

TRADE EXPOSURE PROTECTION IS NECESSARY

The risk of leakage due to costs incurred by California industry, but not their competitors is high. In the last round of amendments to the Cap and Trade regulation (2013-2014), CARB extended 100% of the assistance factor into the second compliance period. As it was in the 2013-2014 timeframe, California’s market remains largely isolated from other markets where more cost-effective reductions exist. Accordingly, an extension of 100% industry assistance is still warranted until such time that leakage risk is eliminated, both to maintain the environmental integrity of the program and to protect California jobs and the state economy. While additional time is appreciated to discuss alternative methodologies for trade exposure, 15-day comment periods are not sufficient time for

affected stakeholders to assess the impacts of the new assistance factors.
(CALCHAMBERCOMMERCE)

Response: This comment is a duplicate of a comment submitted by CalChamber during the 45-day package release. See response to 45-day comment B-6.1 for staff's reply to this comment, as well as related responses to 45-day comments B-6.2 and B-6.5.

B-6.34. Multiple Comments:

3.2 CARB Should Set Cap Adjustment Factors For Industries With Significant Process Emissions Using The Best Data Available

In the draft regulation, CARB proposes to maintain its general approach to establishing cap adjustment factors, including an alternate trajectory for industries with significant process emissions. Specifically, as with the current approach, CARB proposes to reduce the rate of decline in the cap adjustment factor by half for all industries with significant process emissions. This one-size-fits-all approach was appropriate when CARB initially established the program, as it lacked sufficient data on the proportion of process emissions for each industry. However, as demonstrated by the proposed methodology for setting assistance factors, CARB now has verified emissions data on each industry that allows it to calculate industry-specific adjustments. Consistent with its objective of establishing industry-specific assistance factors, CARB should use this more accurate and readily available data to produce industry-specific cap adjustment factors that account for the true proportion of process emissions. (CSCME)

Comment:

I am writing on behalf of Air Liquide Large Industries U.S. LP ("Air Liquide") in response to CARB's proposal, released on December 21, 2016, to amend the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, and specifically with respect to (1) the industries that will receive a non-standard cap-adjustment factor under Section 95891, and (2) the assistance factor that will be applied to hydrogen production.

Air Liquide is the world's leader in industrial and medical gases. Air Liquide and its affiliated companies operate twenty facilities and employ nearly 2,000 people in California. Air Liquide's California operations include two hydrogen production facilities that supply hydrogen to refineries in El Segundo and Rodeo. Air Liquide's affiliated companies also supply hydrogen to, and are developing, hydrogen fueling stations around the State.

Air Liquide has consistently supported California's Cap-and-Trade Program. Air Liquide has submitted comments in the past and submits this letter now to highlight the unique position of the industrial gas sector. Specifically, Air Liquide writes to highlight the sector's high process emissions for CARB's consideration in determining the industries eligible for an increased cap-adjustment factor.

Through 2020, CARB has set an increased, non-standard cap-adjustment factor for certain industries with (a) more than 50% process emissions, and (b) "high" leakage risk. California Code of Regulations, Title 17, Section 95891, Table 9-2. Those industries are nitric acid production (NAICS code 325311), calcium ammonium nitrate solution production (NAICS code 325311), cement manufacturing (NAICS code 327310), and dolime manufacturing (NAICS code 327410). *Id.* The decline in the cap-adjustment factor for these industries from 2012 to 2020 is approximately half the decline for all other industries, which results in a greater allocation of free allowances to these industries. The industrial gas manufacturing sector did not receive the same cap-adjustment factor as these industries because CARB determined that it has "medium" leakage risk.

CARB has not yet determined which industries will receive an increased, non-standard cap-adjustment factor in the post-2020 period. CARB has stated that such industries must have more than 50% process emissions, but in light of the fact that industries are no longer categorized as "high," "medium" or "low" leakage risk, new criteria to decide which industries will qualify for the increased cap-adjustment factor will be required. Air Liquide requests that CARB adopt a more flexible standard that recognizes the importance of high process emissions (irrespective of any other factor) in limiting the future emissions reductions that are possible and increasing an industry's need for free allowances.

Industrial gas manufacturing—hydrogen production—has very high process emissions relative to other industries. Process emissions are non-combustion emissions, which are produced from an industrial process itself, rather than as a result of energy consumed during the industrial process. Process emissions occur, for example, when chemicals or raw materials are produced as a result of a chemical reaction, such as the production of hydrogen through steam-methane reformation.

Air Liquide's hydrogen production process involves the creation of hydrogen gas through the addition of heat and the chemical transformation of water and hydrocarbon molecules into hydrogen, carbon dioxide and carbon monoxide. To make this reaction more efficient, Air Liquide and other industrial gas manufacturers have improved, and continue to improve, the thermal efficiency of the process—the amount of heat required to catalyze the reaction.

However the chemical reaction itself cannot be made more efficient. Each atom of carbon that is contained in the feed gas that undergoes the chemical reaction results in the emission of a molecule of carbon dioxide or carbon monoxide. Only a completely new method of producing hydrogen would reduce these process emissions.

Because Air Liquide cannot reduce its process emissions, a cap-adjustment factor that is based on the assumption that energy efficiencies will gradually reduce emissions will make compliance with the Cap-and-Trade Program's requirements increasingly difficult and expensive. The increasing cost of compliance due to high process emissions sets

Air Liquide and other industrial gas manufacturers apart from other manufacturing businesses.

Both Air Liquide's Rodeo and El Segundo facilities have very high process emissions. On average, the process emissions from these facilities are approximately 90% of total emissions. Only about 10% of emissions result from the combustion of fuel.

CARB's recognition of the industrial gas manufacturing sector's high process emissions in the cap-adjustment factors will produce a fairer Cap-and-Trade Program. Failure to recognize the sector's high process emissions will effectively impose a tax on process emissions that cannot be reduced using the existing technology of hydrogen production. Air Liquide therefore requests that CARB include the industrial gas manufacturing sector, and specifically On-Purpose Hydrogen Gas Production, within the industries that receive an increased, non-standard cap-adjustment factor in Section 95891, Table 9-2.

CARB's December 21, 2016 notice also provides new assistance factors to be used in calculating industry assistance allowances. The proposed assistance factors are based on two studies, one analyzing domestic leakage and the other international leakage. As NERA Economic Consulting has noted in a study submitted to CARB, both studies are subject to substantial uncertainty and do not provide an adequate basis for regulatory policymaking. (AIRLIQUIDE)

Response: Commenters request continued implementation of an alternate cap adjustment factor or factors. As a methodology for identifying higher and lower leakage risk sectors has not yet been established, developing potential alternate cap-adjustment factors is premature. See response to 45-day comment B-6.12 for staff's consideration of alternate assistance factors methodologies. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors, an alternative cap adjustment factor, and industrial allocation would be considered as part of a future rulemaking, and have been removed from this rulemaking. Specifically, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-6.35. Comment:

Seven Percent

CCEEB is greatly concerned that staff selected 7% as an acceptable domestic drop. Some drop in productivity might be acceptable in an academic setting, it should not be factored into the state's future economic plan. We are even more concerned that CARB would consider such a large economic drop acceptable since 7% is similar to the loss California experienced in the Great Recession during which the state lost 1,061,300

non- farm jobs, roughly 7.4%.⁷⁶⁴ For CCEEB's membership a similar downturn would result in thousands of lost high-wage skilled labor jobs with large multipliers that ripple through the California economy. ARB's acceptance of a 7% domestic drop as normal economic fluctuation undercuts industry assistance factors and undercuts the AB32's directive to minimize leakage and equates to the drop experienced during the 2007-09 great recession, allows these amendments to further cut industrial assistance factors. Reduction of industry assistance for trade exposed companies is a simple and minor protection to avoid both environmental and economic leakage. California businesses are trade exposed unless their competitor is in a linked jurisdiction; these include both countries without such linkage as well as individual US states where industry will not have the burden of these costs. In the absence of national or international action comparable to California law CCEEB requests that ARB maintain current industrial assistance factors.

Need for Open Data and Reproducible Study Results

CCEEB is concerned by the difficulty in analyzing the economic impacts of the proposed amendments due to the lack of information on trade exposure status, holding limits, and other cost containment policies (besides the Allowance Price Containment Reserve). ARB is being guided by leakage studies conducted by Resources for the Future and the University of California, Berkeley. However, the raw data and assumptions used for these highly caveated reports are not available. Furthermore, authors of both studies have cautioned against an over reliance on results. We fear that ARB has taken the conclusions from these studies as facts and are proceeding forward without due caution. Examples of the researchers concerns on use of the data:

In the UC Berkeley Paper, Meredith Fowlie explained that the results do not “estimate leakage potential for any particular industry with any degree of precision.” (Fowlie, et al, p. 41) The authors go on to state, “However, the general patterns that emerge are insightful.” (ibid, p. 42) These general patterns include conclusions such as the greater the level of competition, the higher the demand elasticity and the greater the potential for economic and emission leakage. This intuitive result does not appropriately provide a foundation for a leakage analysis that can provide results “with any degree of precision.”

Further, authors explained that it is difficult to accurately identify the point of origin of U.S. trade exports. “This makes it difficult to separately identify California trade flows.” (ibid, p. 16) Authors go on to explain how they use a proxy for purposes of this exercise.

These are but two examples of the difficulty of accurately evaluating the impact of California-only policy on Energy-Intensive Trade-Exposed industries. Given this uncertainty, policy makers must remain focused on the primary goal, reduced GHG emissions.

⁷⁶⁴ <https://data.bls.gov/cgi-bin/surveymost?sm+06>

We ask ARB to work with stakeholders and make the missing information publicly available so that others can reproduce results from the leakage studies. Peer review is essential. This is important since the proposed amendments seek to substantially reduce industry assistance to all sectors, in many cases by half or more compared to today. Regulated entities need access to this information in order to verify findings and determine how proposed program changes will affect California's businesses and economy.

Based on the limited information we currently have available, CCEEB makes the following observations:

ARB appears to be focused on only preventing emissions leakage, to the exclusion of other program goals, including prevention of economic leakage.⁷⁶⁵ Although it might be expected that California facilities are so efficient that emissions leakage and economic leakage are the same, this is not always the case. As applied to manufacturing, which must operate at a relatively efficient capacity, economic leakage could result in reduced investment and manufacturing loss. For example, in both cases below, the manufacturer loses market share to out-of-state competitors even as emissions remain the same or even potentially increase if production is replaced by less efficient sources, i.e., economic leakage occurs without emissions leakage:

- Demand destruction: If California's demand for products decreases, then the amount of emissions associated with California's carbon footprint also decreases. California would consider emissions leakage for products for which there is California demand. If demand drops, however, and industry increases exports but faces out-of-state competition, this results in economic leakage. For example, if demand goes from 100 units to 90, instate supplied 50 but now 30 and out-of-state supplied 50 but now 60, ARB would only address 10 units, not the full 20.
- Increases made by out-of-state producers that have the same emissions as in-state producers may not be considered emissions leakage, but it is economic leakage.

(CCEEB)

Response: CCEEB argues that the seven percent domestic drop is not appropriate for use in the post-2020 assistance factors, and requests that staff rely less on the leakage studies. Staff has postponed establishment of post-2020 assistance factors to allow for continued input by industrial and other

⁷⁶⁵ Page 3, Section 38501 (h) It is the intent of the Legislature that the State Air Resources Board design emissions reduction measures to meet the statewide emissions limits for greenhouse gases established pursuant to this division in a manner that minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality.

stakeholders in developing a revised post-2020 assistance factor framework. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program. CCEEB also requests the raw dataset used to develop the three leakage studies. The raw datasets used by the studies rely on (firm-level) confidential business data, and therefore staff cannot release the datasets. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking, and have been removed from this rulemaking.

CCEEB also requests that staff broaden the scope of emissions leakage prevention to include “economic leakage,” but appears to confuse both the definition of emissions leakage and ARB’s allowance allocation methodology. Regardless of this confusion, CCEEB does not articulate a compelling reason for changing the allowance allocation framework. CCEEB’s request to extend the scope of emissions leakage protection is for allowance allocation to adjust when in-State industry decreases or increases production, rather than adjust based on in-State demand. Staff notes that the definition of product-based allowance allocation is

Allowance allocation = Assistance factor x Benchmark x Cap-adjustment factor x Output.

Therefore, allowance allocation adjusts in response to changes in output. In CCEEB’s example, allowance allocation would decline to levels sufficient to minimize emissions leakage risk for the thirty remaining units. See response to 45-day comment B-6.20 for the reasons staff does not intend to compensate based on changes external to emissions leakage prevention.

B-6.36. Comment:

We support ARB's effort to expand the jurisdiction of cap and trade by linking with other states and Canadian provinces. This levels the playing field in the sector, reducing the concerns over trade exposure and leakage. Unfortunately, there have been no linkages with other states at this time, as each state continues to pursue separate agendas on addressing climate change and greenhouse gas emissions. At this time, we ask that ARB not bank on securing further linkages for cap and trade when constructing these amendments and recognize that other states, including Utah, Washington, Texas, several Midwest states, and many East Coast states, are a serious threat in our sector. Leakage to these states is a real concern as we do not compete on even footing in areas such as regulatory requirements, including cap and trade.
(GRAPHICPACKAGING)

Response: Staff appreciates Graphic Packaging's support for the Cap-and-Trade Program. Staff's prior analysis of leakage does not assume the previous or future implementation of other cap-and-trade or carbon regulations, and encourages Graphic Packaging to continue dialogue and provide input to staff to inform the subsequent rulemaking that will establish post-2020 assistance factors. See response to 45-day comment B-6.3, indicating that post-2020 assistance factors and industrial allocation would be considered as part of a future rulemaking and have been removed from this rulemaking. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program. Staff's mandate is to minimize emissions leakage to the extent feasible as a result of industry's Cap-and-Trade Program's costs. Domestic competitors that are not subject to carbon cost pass-through at similar levels of stringency create a need for careful analysis and can justify allowance allocation.⁷⁶⁶ As stated in the May 24, 2016 emissions leakage study workshop, the establishment of a significant number of new jurisdictional carbon regimes could warrant a review of the allowance allocation necessary to minimize emissions leakage.^{767,768}

B-6.37. Comment:

Fundamentally, Wonderful does not support the Staff Proposal to decrease assistance factors post 2020. We believe that ARB should, at a minimum, maintain the current assistance factors (those allocated in the 3rd compliance period) for 2021-2023, and review additional emissions leakage data from 2018 through 2020 before considering assistance factor refinement. (WONDERFUL)

Response: See staff's response to the 45-day comment B-6.1.

B-6.38. Comment:

Allowance Allocation Formula:

The allowance allocation formula continues to raise concerns among businesses in the regulated community. ARB must take into consideration any unintended consequences

⁷⁶⁶ See staff's response to the 45-day comment B-6.1 for some of the reasons full allowance allocation is not always justified, even when some (or all) of an industry's competition are not subject to a carbon compliance cost.

⁷⁶⁷ As of the May, 2016 workshop, carbon pricing had been implemented for 20 percent of China's 2010 emissions, as well as in the European Union (2005), British Columbia (2008), the Northeastern U.S.' electricity sector (i.e. RGGI), South Korea (2015), and Quebec (2014). Expansions of carbon pricing were expected during 2017 for the remainder of China's emissions in certain sectors, Washington State, and Ontario. Slide 17 "Emissions Leakage Potential and International Climate Agreements" found here:

<https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/staff-leakage-workshop-methodology.pdf>

⁷⁶⁸ Staff's current assistance factor methodology assumes no other jurisdictions have implemented carbon regulations.

that will result in the competitiveness of our California producers along with economic and emissions leakage that will occur should the allocation formula become too rigid.

Reductions in GHGs are driven by the cap, not by allowance allocation. Reductions in GHGs are improved if the state minimizes leakage as required in AB 32 38562(b)(7) because leakage causes emissions outside of the cap to increase. The program can better meet California's climate goals by extending the full industry assistance factor. For these reasons, we recommend that ARB extend full industry assistance factor into future compliance periods. (CCPC)

Response: See responses to 45-day comments B-6.1 and B-6.29 for a discussion of the balance that must be struck between emissions leakage minimization and allocating allowances for other uses, the prior accommodations to help medium and low leakage risk industries prepare for a step down in allocation, the advance knowledge dating from the 2010 regulation that the third compliance period would include reduced allocation, and ARB's mandate to minimize emissions leakage as opposed to allocate for competitiveness issues unrelated to the Cap-and-Trade Program.

C. COVERED SECTORS AND EXEMPT EMISSIONS

C-1. Exemptions

Waste-to-Energy Exemption

C-1.1. Multiple Comments:

We strongly support the proposal to retain the limited exemption for waste-to-energy facilities through the second compliance period. Solid waste management is at a critical juncture here in California and keeping the three waste-to-energy facilities in operation, at least through the second compliance is critical to achieving the legislative goals outlined by SB 1383, and CARB, through the draft Short-Lived Climate Pollutant Reduction Strategy (SLCP).

SB 1383 sets out the extremely aggressive goal of diverting 50% and 75% organics from landfills by 2020 and 2025, respectively. As outlined in the SLCP and the many letters from the solid waste industry, meeting these goals will be very challenging taking a combination of efforts, not only by industry, but by the legislature to provide adequate infrastructure funding, regulatory agencies through streamline of requirements (e.g., permitting and siting), and cities through the development of adequate collection and management of the organic waste stream. All of this will take time. If allowed to continue, the three waste-to-energy facilities in the state will act as an important "bridge" in solid waste management, as the organic infrastructure is organized and built to meet these challenges.

The Sanitation Districts have been aggressively working on solutions to expedite the organic diversion efforts. We currently have put in place the ability to co-digest food

waste with biosolids at our Joint Water Pollution Control Plant in Carson. We are also in the process of seeking funding to expand this program, working with other solid waste industry partners, to increase our food waste digestion throughput and utilize excess biogas to generate transportation fuel. In addition, the Sanitation Districts are working with many associations with the goal to develop increasing infrastructure of organics management. As stated, the efforts to meet the SB 1383 goals will require a combined effort of the solid waste industry, the legislature and regulatory authorities, all working together. Allowing the limited exemption for waste-to-energy facilities through the second compliance period will send a strong message that CARB recognizes the challenges ahead in meeting the SLCP and SB 1383 goals, and is part of this effort.

There are significant greenhouse benefits in operating waste-to-energy plants over landfilling. COVANTA details these advantages in their correspondence. We will not repeat those here but support their analyses. (LASANITATION)

Comment:

We support the proposal to retain the limited exemption for waste-to-energy (“WTE”) facilities through the end of the 2nd compliance period. The three WTE facilities in California help reduce GHG emissions relative to landfilling and landfills continue to be excluded from the cap. Inclusion of WTE in the cap in the 2nd compliance period would impose a significant economic penalty on WTE relative to landfilling, putting the continued operation of these facilities in jeopardy, despite their benefits.

The GHG benefits of WTE relative to landfilling are well recognized, including by CalRecycle,⁷⁶⁹ CARB,⁷⁷⁰ the Center for American Progress,⁷⁷¹ Third Way,⁷⁷² a 2016 report from the Berkeley Law Center for Law, Energy & the Environment,⁷⁷³ U.S. EPA,⁷⁷⁴ U.S. EPA scientists,⁷⁷⁵ the Intergovernmental Panel on Climate Change

⁷⁶⁹ CalRecycle (2012) CalRecycle Review of Waste-to-Energy and Avoided Landfill Methane Emissions. <http://www.calrecycle.ca.gov/Actions/PublicNoticeDetail.aspx?id=735&aiid=689>

⁷⁷⁰ See Table 5 of California Air Resources Board (2014) *Proposed First Update to the Climate Change Scoping Plan: Building on the Framework, Appendix C – Focus Group Working Papers, Municipal Solid Waste Thermal Technologies*

⁷⁷¹ Center for American Progress (2013) Energy from Waste Can Help Curb Greenhouse Gas Emissions <http://www.americanprogress.org/wp-content/uploads/2013/04/EnergyFromWaste-PDF1.pdf>

⁷⁷² Third Way (2014) *Power Book: Energy from Waste*, <http://powerbook.thirdway.org/filter-web-app/energy-from-waste>, accessed November 26, 2014.

⁷⁷³ Berkeley Law Center for Law, Energy & the Environment (2016) *Wasting Opportunities: How to Secure Environmental & Clean Energy Benefits from Municipal Solid Waste Energy Recovery*. <https://www.law.berkeley.edu/research/clee/research/climate/waste-to-energy/>

⁷⁷⁴ U.S. EPA Office of Solid Waste, Energy Recovery from the Combustion of Municipal Solid Waste (MSW), <https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw#EnergyRecovery>, accessed January

⁷⁷⁵ Kaplan, P.O, J. DeCarolis, and S. Thorneloe (2009) Is it better to burn or bury waste for clean electricity generation? *Environ. Sci. Technology* 43 (6) pp1711-1717. <http://pubs.acs.org/doi/abs/10.1021/es802395e>

("IPCC"),⁷⁷⁶ the World Economic Forum,^{777 778} and the European Union,⁷⁷⁹ WTE facilities are not covered under the EPA's new Clean Power Plan.⁷⁸⁰ WTE facilities are considered zero carbon power under the CPP's accounting structure and new WTE facilities are eligible to generate Emission Rate Credits (ERCs).⁷⁸¹ The conclusions of these organizations and government entities is consistent with the scientific literature, as demonstrated by the conclusion reached by Joint Institute for Strategic Energy Analysis (JISEA)⁷⁸² scientists:

*"Life cycle assessment studies published in the literature have generally been consistent in suggesting that MSW combustion is a better alternative to landfill disposal in terms of net energy impacts and CO₂-equivalent GHG emissions. The results from this study match that expectation. In this report, WTE leads to a higher reduction in emissions compared to landfill-to-energy disposal per kWh production."*⁷⁸³

The recognition given to WTE is in large part a result of its ability to avoid emissions of the potent GHG methane. WTE's climate benefits are even more striking in light of methane's role as a short lived climate pollutant ("SLCP"). New data show that the methane emitted by landfills and other sources is even more damaging than previously thought. Methane is the second largest contributor to global climate change.⁷⁸⁴

⁷⁷⁶ EfW identified as a "key mitigation measure" in IPCC, "Climate Change 2007: Synthesis Report. Contribution of Work Groups I, II, and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change" [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]. IPCC, Geneva, Switzerland, 104 pp.

http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_synthesis_report.htm

⁷⁷⁷ EfW identified as a key technology for a future low carbon energy system in World Economic Forum. *Green Investing: Towards a Clean Energy Infrastructure*. January 2009. Available at: <http://www.weforum.org/pdf/climate/Green.pdf>

⁷⁷⁸ EU policies promoting EfW as part of an integrated waste management strategy have been an overwhelming success, reducing GHG emissions over 72 million metric tonnes per year, see European Environment Agency, *Greenhouse gas emission trends and projections in Europe 2009: Tracking progress towards Kyoto targets* http://www.eea.europa.eu/publications/eea_report_2009_9

⁷⁷⁹ European Environmental Agency (2008) Better management of municipal waste will reduce greenhouse gas emissions. Available at:

http://www.eea.europa.eu/publications/briefing_2008_1/EN_Briefing_01-2008.pdf

⁷⁸⁰ 40 CFR 60.5845

⁷⁸¹ 40 CFR 60.5800

⁷⁸² The Joint Institute for Strategic Energy Analysis (JISEA) is operated on behalf of the U.S. Department of Energy's National Renewable Energy Laboratory (NREL), the University of Colorado-Boulder, the Colorado School of Mines, the Colorado State University, the Massachusetts Institute of Technology, and Stanford University.

⁷⁸³ Joint Institute for Strategic Energy Analysis (2013) *Waste Not, Want Not: Analyzing the Economic and Environmental Viability of Waste-to-Energy (WTE) Technology for Site-Specific Optimization of Renewable Energy Options*. <http://www.nrel.gov/docs/fy13osti/52829.pdf>

⁷⁸⁴ See Figure SPM.5 of IPCC (2013) *Summary for Policymakers*. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., et al. (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_SPM_FINAL.pdf

Methane has a much larger climate impact than previously reported and its atmospheric concentrations continue to rise (Figure 5).⁷⁸⁵ According to the IPCC's 5th Assessment Report, methane is 34 times stronger than CO₂ over 100 years when all of its effects in the atmosphere are included and 84 times more potent over 20 years.⁷⁸⁶

In response to the growing concern about methane and other SLCPs, CARB has developed a *Proposed Short-Lived Climate Pollutant Reduction Strategy* for California. The use of a the 20 year global warming potential of 72, nearly three times larger than the GWP used in CalRecycle's 2012 analysis, further underscores the benefits of EfW relative to landfilling:

*"The use of GWPs with a time horizon of 20 years better captures the importance of the SLCPs and gives a better perspective on the speed at which SLCP emission controls will impact the atmosphere relative to CO₂ emission controls."*⁷⁸⁷

California's WTE facilities provide other important benefits as well. The facilities in Long Beach and Stanislaus are the only two locations in California permitted to destroy narcotics. Since 1988, the Southeast Resource Recovery Facility ("SERRF") in Long Beach has destroyed 11.2 million pounds of confiscated narcotics and drug paraphernalia for over 121 cities, counties, state, and federal law enforcement agencies. Stanislaus has processed over 216 tons of confiscated narcotics, firearms and drug paraphernalia in 2016 for over a 100 cities, counties, state and federal law enforcement agencies. (COVANTA)

Comment:

CCEEB supports the proposal to retain the limited exemption for waste-to-energy facilities through the second compliance period. Solid waste management is at a critical juncture here in California and keeping the three waste-to-energy facilities in operation, at least through the second compliance is critical to achieving the legislative goals outlined by SB 1383, and CARB, through the draft Short-Lived Climate Pollutant Reduction Strategy (SLCP). (CCEEB)

⁷⁸⁵ World Meteorological Organization (2014), *WMO Greenhouse Gas Bulletin: The State of Greenhouse Gases in the Atmosphere Based on Global Observations through 2013*, 10, September 9, 2014. Available at: <https://drive.google.com/file/d/0BwdvoC9AeWjUd0IPWXBMU1VmNGc/view>

⁷⁸⁶ The IPCC concluded that "it is likely that including the climate-carbon feedback for non-CO₂ gases as well as for CO₂ provides a better estimate of the metric value than including it only for CO₂." See p714 & Table 8-7 of Myhre, G. *et al.* (2013) *Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., *et al.* (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

⁷⁸⁷ CARB (2016) *Proposed Short-Lived Climate Pollutant Reduction Strategy* <https://www.arb.ca.gov/cc/shortlived/meetings/04112016/proposedstrategy.pdf>

Comment:

Long Beach strongly supports CARB staff's recommendation to formalize the limited exemption in the 2nd compliance period for waste-to-energy facilities; and understands these facilities will be subject to compliance during the 3rd compliance period, beginning in 2018...

Given these reasons, the City of Long Beach supports the following components in CARB's 15-day language pertaining to *Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms*, and looks forward to working with CARB on a path towards allowances.

§ 95802. Definitions.

(393) "Waste-to-Energy Facility" means a facility located in California that combusts eligible municipal solid waste. The facility must operate in accordance with a current permit issued by the local Air Pollution Control District or Air Quality Management District to generate and distribute electricity over the electric power grid for wholesale or retail customers of the grid located in California.

§ 95831. Account Types.

(6) Annual Allocation Holding Account. When an entity qualifies for a direct allocation under ~~section 95870~~ subarticle 9, the accounts administrator will create an annual allocation holding account for the entity.

(H) Allocation of allowances to waste-to-energy facilities will be transferred on January 1 of the vintage year of the allowances to the entity's compliance account pursuant to section 95852(k).

§ 95851. Phase-in of Compliance Obligation for Covered Entities.

Operators of eligible Waste-to-Energy Facilities, pursuant to section 95852(k), that meet or exceed the annual threshold in section 95812(d), will have a compliance obligation beginning in 2016~~8~~

§ 95852. Emission Categories Used to Calculate Compliance Obligations.

Limited Exemption of Emissions for Waste-to-Energy Facilities. Emissions reported and verified in the first and second compliance periods and in data year 2015 for the direct combustion of municipal solid waste in a waste-to-energy facility that had started operations before 2009 and that meets the requirements of this section do not have a compliance obligation and shall not count toward the inclusion threshold of section 95812(d)(3). The Executive Officer will place the number of true-up allowances equal to the facility's reported, verified, and covered emissions from municipal solid waste for the 2016 and 2017 data years into their compliance account. These allowances will be used to meet the facility's 2016 and 2017 compliance obligations. The 2018 vintage true-up allowances will be deposited by October 24, 2017 for the 2016 data year's reported and

verified emissions. The 2019 vintage true-up allowances will be deposited by October 24, 2018 for the 2017 year's reported and verified emissions. The Executive Officer will retire the allowances placed into the account according to the surrender dates in section 95856. The exempted waste-to-energy facility must meet the following criteria:

(1) Operators of Waste-to-Energy Facilities must register in the tracking system pursuant to section 95830; (CITYLONGBEACH)

Response: The comments express support for the proposal to retain the limited exemption for waste-to-energy facilities through the second compliance period. Thank you for the support. With respect to the portion of the comment that indicates that WTE facilities are not covered under the Clean Power Plan, the comment is out of the scope of the first 15-day package.

C-1.2. Multiple Comments:

Path Forward for 3rd Compliance Period

We recognize that the GHG benefits of WTE relative to landfilling may change, especially in light of SB1383 and other steps taken by CARB, CalRecycle, and the Legislature to encourage the diversion of organics from landfills. As more organics are diverted from landfills, landfills will begin to generate, and emit, less methane. This is an outstanding result for the environment, both in terms of more sustainable waste management and lower GHG emissions. We believe WTE will continue to have a valuable role to play as part of an integrated waste management strategy; however, the particular climate benefits achieved by WTE relative to the states' landfills will likely change over time.

We further recognize that CARB needs a long term approach for the equitable treatment of waste management under the cap and trade program to meet the directives of CARB Board Resolutions passed in October 2011 and September 2012. Over the short-term, these resolutions resulted in the previous exemptions for WTE facilities which are currently proposed to extend through 2017. However, a long term solution that "aligns with statewide waste management goals [and] provides equitable treatment to all sectors involved in waste handling"⁷⁸⁸ and represents a "comprehensive approach for the most appropriate treatment under the cap and trade program for all end of life management options for MSW"⁷⁸⁹ is still needed. Such a solution needs to consider the regulatory approach of the program, organics diversion and other changes to the waste stream, and the continued exclusion of landfills from the cap & trade program until at least 2025 provided by SB1383.⁷⁹⁰

⁷⁸⁸ CARB (2016) *Proposed Short-Lived Climate Pollutant Reduction Strategy*
<https://www.arb.ca.gov/cc/shortlived/meetings/04112016/proposedstrategy.pdf>

⁷⁸⁹ Board Resolution 12-33

⁷⁹⁰ See Section 3(b) of SB 1383

In response, we are proposing a long-term solution that would include WTE facilities in the cap beginning with the 3rd compliance period in 2018 with a provision for allowances to be granted on the basis of the output-based allocation approach outlined in the regulation. This approach will both include WTE in the cap and trade program and provide a more level and equitable playing field in the waste management sector over the long-term, thereby preventing emissions leakage out of the cap to landfills, without including landfills in the cap (an action that, while equitable when properly implemented, is prohibited by SB 1383 until 2025).

Output-Based Allowance Allocation Proposal

We propose that WTE be allocated allowances consistent with §95891 of the Proposed Regulation through the development of a benchmark (B_a) for the management of MSW remaining after recycling. Based on current practices (over 97% of California's waste remaining after recycling is disposed in landfills),⁷⁹¹ we propose the benchmark be set on the basis of managing MSW in landfills. Unlike other benchmarks, however, we propose the MSW benchmark be subject to change over time to account for the demonstrated decreasing share of organics in the waste stream as a result of organics diversion efforts. We propose that benchmark be calculated on the basis of the fraction of anaerobically degradable organic carbon (%ANDOC) present in the waste stream as determined through the most recent waste characterization study prepared by CalRecycle, adjusted to represent the waste processed at the WTE facility (Equation 1). For example, WTE facilities in California do not typically take construction & demolition (C&D) or most bulk items. This variability in the benchmark is necessary to ensure that it accurately reflects the decreasing amount of methane generated from landfills as a result of changes to the waste stream. The use of the CalRecycle waste characterization study ensures that the benchmark would be tied to regularly updated and publically available data.

$$B_a = 90\% \times \%ANDOC \times 5.95 \frac{tCO_2e}{ton ANDOC} \quad (1)$$

Where:

- 90% = Stringency factor⁷⁹²
- %ANDOC = Anaerobically degradable organic carbon as a mass % of waste (ton carbon / ton waste) (*Variable*, based on latest CalRecycle waste characterization report, adjusted for wastes not taken at specific WTE facility, e.g. C&D, most bulky items)

⁷⁹¹ CalRecycle (2016) *State of Disposal in California, Updated 2016*
<http://www.calrecycle.ca.gov/Publications/Documents/1556/201601556.pdf>

⁷⁹² 90% stringency factor is in accordance with Appendix J to October 28, 2010 Initial Statement of Reasons for the Proposed Regulation to Implement the California Cap-and-Trade Program

5.96 = Metric tonnes of CO₂ equivalents per ton of ANDOC, calculated from CalRecycle (2012) *Review of Waste-to-Energy and Avoided Landfill Methane Emissions (Constant)*⁷⁹³

Consistent with the allowance allocation equation in §95891(b), we propose the benchmark be used together with the annual waste throughput at the WTE facility and the appropriate cap adjustment and assistance factors from the Proposed Regulation to determine the allowances provided to WTE facilities (Equation 2).

$$\text{Initial Allocation}_{WTE} = O_{t-2} \times B_a \times AF \times c_t + \text{Metals Allowance} \quad (2)$$

Where:

O_{t-2} = Waste throughput at WTE facility

B_a = Benchmark Factor for waste disposal / transformation, based on organics fraction in disposed waste

AF = Assistance Factor, 100% based on high risk for leakage

c_t = Cap adjustment factor from Table 9-2, for sectors with process emissions greater than 50%

WTE facilities have little ability to control the amount of stack GHG emissions subject to the cap and trade program. The emissions from the transformation of MSW are dependent on the waste composition, most notably the overall carbon content, and the fraction of carbon that is from biologically derived materials, neither of which can be readily controlled by the WTE owner or operator.

Therefore, in order to provide an opportunity for WTE facilities to reduce their regulated GHG emissions while achieving a tangible and quantifiable environmental benefit, we propose that allowances be granted for the recovery of metals. Such an approach would incentivize the installation of advanced metals recovery technologies at WTE facilities, which, by recovering additional metals from the waste stream that would have otherwise been lost in landfills, result in net GHG benefits from the avoidance of GHG emissions that would have occurred during the manufacture of metals from raw materials. Although these GHG reductions do not occur at the WTE facility, they are a direct result of the recovery equipment installed, and the actions taken, at the WTE facility.

The metals allowance should be calculated on the basis of the actual metals recovery at a WTE facility multiplied by U.S. EPA GHG savings factors for metals recycling (Equation 3). Consistent with the cap and trade program, the allowances would be subject to a stringency factor and the cap adjustment factors.

⁷⁹³ CalRecycle reported average total landfill emissions of 0.53 t (metric ton) CO₂e / ton waste, based on a methane global warming potential (GWP) of 25, and an adjusted 8.9% ANDOC. Dividing the total landfill emissions by the adjusted % ANDOC provides a factor that can be applied to wastes with different %ANDOC. The calculation of this factor is as follows: (0.53 t CO₂e / ton MSW) / (0.089 ton ANDOC / ton MSW) = 5.96 t CO₂e / ton ANDOC.

$$\text{Metals Allowance} = 90\% \times c_t \times AF \times (R_{Fe} \times f_{Fe} \times R_{Non-Fe} \times f_{Non-Fe}) \quad (3)$$

Where:

90%	=	CARB stringency factor
c_t	=	Cap adjustment factor from Table 9-2, ⁷⁹⁴ for sectors with process emissions greater than 50%
R_{Fe}	=	Recovery of ferrous metals (tons)
R_{Non-Fe}	=	Recovery of non-ferrous metals (tons)
f_{Fe}	=	GHG Benefit factor for ferrous metals recycling, 1.81 t CO _{2e} / ton Fe metal ⁷⁹⁵
f_{Non-Fe}	=	GHG Benefit factor for non-ferrous metals recycling, reflecting 80% aluminum and 20% copper, 8.2 t CO _{2e} / ton non-Fe metal ⁷⁹⁶

Selection of Appropriate Assistance and Cap Adjustment Factors

WTE facilities face a high leakage risk. The three WTE facilities in California operate in a highly competitive environment with landfilling. Landfills have a near monopolistic market share of 97% of the post-recycled waste management services provided in California. As a result, landfill operators exercise significant control over tip fees, or the price charged to dispose of a ton of waste. WTE facilities already charge higher tip fees than local landfill options,⁷⁹⁷ and, as discussed earlier, landfills are not currently regulated under the cap and trade program and are explicitly protected from inclusion in cap and trade until 2025. Consequently, WTE facilities owners and operators have little ability to pass through costs from the cap and trade program to customers.

When looking strictly at stack GHG emissions without consideration of the net benefits of WTE, WTE facilities have a high emissions intensity. Using tip fees as a conservative and absolute upper bound for the “value-added” from post recycled waste management, the weighted average emissions intensity of the three WTE facilities in California is above the 5,000 t CO_{2e} / \$M value added threshold for a “high emission intensity.” In other words, the financial exposure to WTE operators is significant relative to the cost of service. The three WTE facilities face a potential 3rd period compliance cost collectively of over \$14 million without allowances. If WTE received no allowances in recognition of their GHG mitigation or to mitigate leakage risk, municipalities using WTE facilities

⁷⁹⁴ The Proposed Regulation no longer specifically identifies “Sectors with Process Emissions Greater Than 50%” within the headings to table 9-2, but specifies NAICS codes which include “activities with over 50 percent of total emissions from process emissions and a high leakage risk classification in Table 8-1.” We are proposing that the NAICS code for municipal waste combustion, 562213, be added to the heading of Table 9-2.

⁷⁹⁵ See Exhibit 2-2 of U.S. EPA (February 2016) Documentation for Greenhouse Gas Emission and Energy Factors Used in the Waste Reduction Model (WARM): Management Practices Chapters https://www.epa.gov/sites/production/files/2016-03/documents/warm_v14_management_practices.pdf

⁷⁹⁶ *Ibid.*

⁷⁹⁷ See Figure 2 of CalRecycle (2015) *Landfill Tipping Fees in California*, <http://www.calrecycle.ca.gov/publications/Documents/1520%5C20151520.pdf>

would face a significant compliance cost that would need to be met through raising fees (already demonstrated to be difficult in a marketplace dominated by landfills), cutting services, or sending MSW to landfills. Given the high leakage risk and the calculated high emissions intensity, we propose that the assistance factor associated with the high leakage risk classification from Table 8-1 of the Proposed Regulation be applied to the three WTE facilities in the 3rd compliance period.

Process emissions associated with the anaerobic decomposition of organics in landfills dominates the emissions from the waste management sector. As described above, landfills dominate the sector, managing 97% of the annual post-recycled MSW generated in the state. As a result, we propose that the cap adjustment factor for those activities with a high leakage risk classification and greater than 50% of total emissions from process emissions be applied to WTE facilities.

We believe that a long-term strategy and solution is necessary. Conceptually, landfills and WTE should be treated consistently with regard to GHG emissions, so that the cost of carbon for both process that manage post-recycled MSW can be accurately reflected, thereby providing the appropriate market signal. In an idealized market, this market signal would incentivize waste management options with the lower carbon intensity. Today, as is recognized internationally and by California, this more efficiency process is WTE.

However, landfills do not receive a market signal, nor will they be exposed to one until at least 2025. This significantly complicates creating a level playing field in the waste management sector, especially given that CARB plans to include WTE in the cap beginning in 2018. However, we believe the allowance mechanism outlined above can help approach a level playing field. While the approach subjects WTE to a compliance obligation in conflict with the understanding that WTE is preferable to landfills, allowances will help alleviate the financial burden on those communities who use and/or own WTE facilities, and, most importantly, help prevent leakage of emissions out of the cap to landfills. The approach operates within a system already established by the regulation and will expose WTE to a carbon price while providing some options for reducing financial exposure and reducing GHG emissions through metals recovery projects.

The approach is conservative: it relies on a long-term methane GWP which is less reflective of methane's short term impacts that are a key focus of the states' SLCP plan, it relies on an older methane GWP which underestimates even the long term impact of CH₄, and its recognition of WTE's benefits diminishes over time, not in consideration of a science-based reality, but in an effort to fit within the cap adjustment and assistance factor regulatory constructs. It also recognizes that the waste stream will change over time, as a result of the laudable efforts on the part of CARB, CalRecycle, and the state legislature to divert organics from landfills. Perhaps most importantly, the approach is performance-based: the calculation of allowances is based on actual emissions, waste

processed, and demonstrated changes in the waste stream as revealed by CalRecycle's period waste characterization reports. (COVANTA)

Comment:

In partnership with Covanta Energy, Long Beach proposes a long-term solution that would include waste-to-energy facilities in the cap beginning in the 3rd compliance period with a provision for allowances to be granted on the basis of the output-based allocation methodology. This approach provides a more level and equitable playing field in the waste management sector over the long-term, thereby preventing emissions leakage out of the cap to landfills. The City of Long Beach supports the methodology proposed in Covanta Energy's comment letter on this issue. (CITYLONGBEACH)

Response: The commenters describe and express support for a proposed approach for allocating allowances to waste-to-energy facilities. Since ARB staff did not propose any modifications to the current methodology in this rulemaking, a new methodology that could be used to allocate allowances to waste-to-energy facilities is out of the scope of the current amendments, and would have to be considered for a future rulemaking. In developing an allocation methodology for waste-to-energy facilities, ARB staff will follow key principles that have underpinned allocation methodology development throughout the Cap-and-Trade Program, some of which are in opposition to the commenters' proposal. Allocations will not be issued for emissions associated with electricity that is sold or provided offsite, as GHG costs should be passed through to the electricity purchaser/consumer. Further, ARB does not allocate to electricity generators except in the limited case of legacy contract generators. Therefore, any future allocation methodology, if any, would need to calculate a reduction in allowances commensurate with the amount of sold electricity. In addition, ARB creates benchmarks based on historical data, not projections, and does not allocate for emissions that are generated outside of covered facilities. Therefore, the proposal to allocate allowances for "avoided landfill emissions" to waste-to-energy facilities is fundamentally problematic. With respect to the point that landfills are not subject to regulations under the Cap-and-Trade Program, this is correct, though staff points out that landfills are regulated for greenhouse gases under California's Landfill Methane Control Measure, which requires the installation of a landfill gas collection and control systems on landfills that meet certain criteria.

Biofuel Exemptions

C-1.3. Comment:

- i. Do not exempt biomass burning activities (EJAC)

Response: ARB has not proposed any changes to the exemptions related to biomass and, as such, the proposal to eliminate the exemption of biomass

combustion emissions from a compliance obligation is outside the scope of the current rulemaking.

Fuel Cell Exemption

C-1.4. Comment:

We have met with the ARB staff to discuss our concerns with the proposed removal of fuel cells from the list of emission sources without a Cap-and-Trade compliance obligation (i.e., Section 95852.2) and appreciate their attention to this important issue. After reviewing the 15-day language, Bloom Energy remains concerned by the proposed removal of fuel cell energy systems from the Section 95852.2 of the Cap-and-Trade program regulations.

The rationale provided for removing fuel cells from Section 95852.2 has been that it is needed to maintain consistency with a broader trend towards removing exemptions and fully accounting for all emissions. We respectfully disagree with this rationale. Fuel cells are the only emissions source that is being removed from Section 95852.2⁷⁹⁸, and a new exemption is being added for fermentation emissions.⁷⁹⁹

In the original Cap-and-Trade rulemaking, the ARB included fuel cells in Section 95852.2. The significance of including fuel cells in Section 95852.2 and the letter you sent to Bloom Energy dated May 23, 2013 confirming the treatment of fuel cells cannot be overstated-- it offers a clear demarcation that fuel cells are GHG reducing with cobenefits that afford them unique treatment in recognition of these important attributes. The proposed amendments to the Cap-and-Trade program currently under Board consideration make a fundamental change to the regulation that will disrupt the market success of GHG reducing fuel cells. The proposed change would remove fuel cells from Section 95852.2 and lead to direct regulation of a small number of operators, but impact the perception of fuel cells for all customers regardless of whether they are a covered entity.

An important point of comfort for all customers is that fuel cell systems will not be directly regulated by the Cap-and-Trade program because they reduce GHG emissions. There is a broad perception that regulation under the Cap-and-Trade program means that the technology has no GHG-benefits because the Cap-and-Trade program is designed to discourage dirty technologies. We appreciate that this is not the ARB's intent, but we want to make sure that the ARB is aware of the perception.

In addition, customers would need to factor into their purchase decision the potential overhead costs of retaining staff to ensure and monitor compliance - costs that would be

⁷⁹⁸ Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, December 21, 2016, page 135-6.

⁷⁹⁹ *Ibid.*, page 136.

perceived as directly resulting from the purchase of a fuel cell that is otherwise cleaner than their current source of power. Direct regulation will not only pose a higher cost as small participants cannot manage their administrative costs as well as larger participants such as the natural gas sector, but there will be an intangible cost in the form of a new regulatory burden and risk.

Natural gas fuel cells are already accounted for in the Cap-and-Trade regulation via the phase in of the natural gas sector beginning in 2015. We appreciate that the phase in of the natural gas sector may lead to a partial minimization of Cap-and-Trade costs compared to other sources over 25,000 MT. We also appreciate that delay in the implementation of the natural gas compliance costs are a source of concern. However, any perceived preferential treatment a small number of fuel cell systems may currently receive is temporary and will in short order be accounted for via the full implementation of natural gas sector compliance. As the compliance costs are implemented and the natural gas sector is subject to a growing allowance consignment ratio, at some point between 2020 and 2030, fuel cell operators will face the same GHG costs as sources directly regulated by the Cap-and-Trade program. In fact, as recently as October 21st, the ARB staff proposed a 100% consignment date by 2021, which would ensure that sources not otherwise directly regulated by the Cap-and-Trade program bear 100% of the natural gas utility's carbon costs by 2021. Thus, as the natural gas sector is transitioned into the Cap-and-Trade program, natural gas fuel cells will face indirect compliance costs paid to the utility and will be accounted for under the cap. As outlined in your 2013 letter, such compliance costs associated with emissions from natural gas use will effectively spur private investment in efficient technologies, such as fuel cells.

Direct regulation of fuel cells is counterproductive to the broader goals of AB 32 and AB 197. Fuel cell systems are much lower GHG emissions sources than conventional natural gas generation. There is no combustion, and as a result, fuel cells also emit no criteria pollutants. It is precisely the type of activity that will "complement federal and state ambient air quality standards and reduce toxic air contaminant emissions" envisioned in AB 32 (i.e., Cal. Health and Safety Code Sec. 38562(b)(4)). Retaining fuel cells in Section 95852.2 is also consistent with the direction in AB 197 to encourage direct emissions reductions at large stationary sources (i.e., Cal. Health and Safety Code Sec. 38562.5(a)). Retaining fuel cells in Section 95852.2 is a longer-term step that will lead to GHG reductions and reductions in criteria pollutants.

We urge you to recognize that direct regulation of fuel cells can actually lead to foregone emission reductions associated with fuel cells and that any associated emissions will be managed in short order via full consignment in the natural gas sector. (BLOOMENERGY)

Response: Please refer to the response for 45-day comment C-1.11, which answers this comment.

D. ELECTRICITY

D-1. Clean Power Plan (CPP)

D-1.1. Comment:

Federal Clean Power Plan Requirements. The draft regulations include a number of provisions related to the implementation of California's plan for complying with the Federal Clean Power Plan. We note that, in some sections, the regulation clarifies that the provisions are only applicable if the U.S. Environmental Protection Agency approves California's compliance plan. In others, ARB staff limits the applicability of the section to having federal approval of the Clean Power Plan *by a date certain*. For example, changes to the Program compliance periods would only apply if the CPP is adopted by January 2019. For consistency, and to ease future amendments to the regulation, we recommend that ARB align all provisions linked to CPP implementation with a date-certain approach.

In addition, all compliance deadlines included in the MRR or in CPP-related changes to the Cap-and-Trade Program should be similarly timed. This will help streamline reporting requirements and align evaluation processes. Until the CPP is in full force and California's CPP compliance plan has been approved by U.S. EPA, ARB should ensure that compliance with the Cap-and-Trade Program (as modified after the adoption of this regulatory package) does not require entities with compliance obligations to spend additional funding on meeting provisions that solely address CPP implementation. (SCPPA)

Response: See response to 45-day comment D-1.6.

D-1.2. Comment:

Do not commit California to continuing Cap-and-Trade through the Clean Power Plan. Since carbon trading cannot be verified, ensure that the Clean Power Plan power purchases are from sustainable, renewable power plants. (EJAC)

Response: See response to 45-day comment D-1.2.

D-1.3. Comment:

California should aggressively pursue additional full linkage with other jurisdictions exploring mass-based carbon regulations. 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. (PG&E)

Response: See response to 45-day comment I-1.1.

D-2. Energy Imbalance Market (EIM) Imports

Accounting For Imported Electricity Emissions from EIM and Addressing Emissions Leakage

D-2.1. Multiple Comments:

As discussed in detail in Powerex's previous comments,⁸⁰⁰ the current EIM algorithm does not accurately identify the out-of-state resources that actually are dispatched in order to support EIM transfers of electricity to serve California load. Powerex believes that the current EIM algorithm is having a number of unintended adverse consequences, including:

1. Understating the actual GHG emissions associated with additional out-of-state dispatch to serve California load in the EIM, with the result that *too few GHG emissions allowances are retired* under California's Cap-and-Trade program.
2. Under certain circumstances, the EIM algorithm can make out-of-state resources erroneously appear more economic than in-state resources. This *can result in "leakage" by improperly shifting GHG emissions from in-state resources to out-of-state resources*, even when the out-of-state resources are not lower cost (when GHG costs are included).
3. Under certain circumstances, the EIM algorithm does not consider differences in GHG emissions in the selection of which out-of-state resource to dispatch. Because GHG costs are not accurately considered by the EIM algorithm, *the EIM cannot appropriately dispatch low- or zero-emitting out-of-state resources over higher-emitting out-of-state resources*.

Recognizing that it may not be feasible to implement the "two-pass" solution until late 2017 at the earliest, CARB proposes a bridge solution beginning January 1, 2018 to support accurate accounting while CAISO works to implement its long-term approach. Under CARB's proposed interim solution, CARB will retire additional GHG allowances to account for "outstanding emissions" that support EIM transfers to support California load, but that are not assigned to any EIM participants under the current EIM algorithm.

Powerex believes that this interim solution is an important step forward towards ensuring accurate GHG accounting in the EIM. It is important to recognize, however, that the interim solution will only address the first adverse consequence identified above; it will not do anything to ensure that GHG costs are appropriately taken into account in CAISO's dispatch processes. Instead, it appears that until the two-pass

⁸⁰⁰ See Comments of Powerex on CARB's October 21 Stakeholder Workshop on Proposed Amendments to the Cap- and-Trade Regulation (Nov. 4, 2016), available at <https://www.arb.ca.gov/lists/com-attach/39-ct-amendments-ws-ViZVPFUjWW9WlgFk.pdf>, and Comments of Powerex on CARB's Proposed 45-day Rulemaking (Sept. 9, 2016), available at <https://www.arb.ca.gov/lists/com-attach/4-capandtrade16-WzhQQQRoWGYGZQRq.pdf>.

design for GHG compliance is implemented in the EIM, the other two adverse consequences experienced to date will persist. Specifically, there will continue to be instances in which high-emitting out-of-state resources will be dispatched in connection with imports serving California load, even if lower-emitting out-of-state or in-state resources are available. For that reason, while Powerex supports the implementation of a bridging solution, it believes it remains vital that the full two-pass solution be implemented in a timely manner, consistent with appropriate pre-implementation testing and validation. Powerex understands CAISO is working towards achieving this objective. (POWEREX)

Comment:

CMUA and its members continue to believe that the magnitude of this issue does not warrant extraordinary regulatory changes. While CMUA has concerns with the EIM Outstanding Emissions calculation and believes it likely overstates the potential problem, even if the calculation is correct, the amount of outstanding emissions is extraordinarily small. We urge the ARB to rethink its prioritization and to focus on other more critical matters presented within the regulation. Rather than implementing a temporary or “bridging” solution, the ARB should wait for the CAISO to craft a market-based solution that will solve this issue within the optimization. CAISO has, indeed, indicated that a solution could be available as early as the end of 2018.

The Proposed 15-Day Modifications include new regulatory language to implement ARB’s temporary solution to this issue:

(D) EIM Outstanding Emissions. Beginning January 1, 2018, ARB will retire current vintage allowances designated by ARB for auction pursuant to section 95911(f)(3) that remain unsold in the Auction Holding Account for more than 24 months in the amount of EIM Outstanding Emissions as defined in section 95111(h) of MRR.

(1) EIM Outstanding Emissions are equal to the annual metric tons of CO₂e from electricity that is imported into California through CAISO’s EIM but not otherwise accounted for by emissions reported by the EIM participating resource scheduling coordinators. These emissions are calculated pursuant to the requirements in MRR section 95111(h)(1).

(2) On an annual basis, ARB will retire these allowances no later than the surrender deadlines specified in sections 95856(d) and (f). ARB will retire allowances starting with the earliest vintages first.

(3) Current vintage allowances retired by ARB pursuant to this section do not include allowances consigned to auction pursuant to section 95910(d).⁸⁰¹

⁸⁰¹ See Proposed 15-Day Modifications, § 95852(b)(D).

It appears the proposed regulations account for the EIM Outstanding Emissions through a reduction in the pool that remains in the Auction Holding Account and is unsold for a specified period of time. While this approach lacks direct price signals for EIM imports, it may be an acceptable short-term bridge until a market solution is developed. However, it must be accompanied by a more rigorous examination of the details of what constitutes EIM Outstanding Emissions. We are concerned that the use of a system-wide unspecified resource emissions factor for actual GHG emissions from participating resources will not accurately capture the GHG emissions caused by California imbalances.

First, California policy should encourage low emitting resources to bid into the EIM. When lower marginal cost resources set market clearing prices, then the overall long-term effect is the creation of price pressures and the decrease of dispatch of higher marginal cost resources, including older thermal units. This effect on the markets is not likely to be offset by uncaptured emissions, or substitution of higher emitting resources to serve load that was otherwise served by lower emitting resources before the EIM optimization...

The proposed unspecified resource solution would have to be reevaluated continually to track the system average emission calculation...

Finally, CMUA asks for clarity on how its members that may become EIM Entities will be affected by the proposed regulations. To date, the Balancing Authority of Northern California ("BANC") and the City of Los Angeles, Department of Water and Power have publicly expressed intent to explore EIM participation. BANC has completed EIM studies and further action to become an EIM Entity has been authorized by the BANC Commission, its governing body. This is a result that the State has encouraged and championed. Certain BANC members import specified renewable resources into California. These resources include wind in the Pacific Northwest, the output of which is secured under long term power purchase agreements. It would be counterproductive if these publicly owned electric utilities ("POUs"), who could potentially bring significant benefits to the EIM, were subject to adverse impacts of EIM participation to which they would not be exposed if they remained outside of the EIM footprint.

(CALMUNIUTILASSOC)

Comment:

The ISO supports efforts to accurately account for greenhouse gas emissions in California's electricity sector and will continue to work collaboratively with state agencies and stakeholders to advance this objective. Over the last several years, the ISO and ARB have worked to align the ISO's market rules with ARB's regulations. This alignment needs to continue...

Recently, the ISO and ARB staff have discussed a proposed enhancement to the ISO's market optimization to address concerns that the current dispatch may not accurately

capture secondary emissions associated with the dispatch of external resources.⁸⁰² The ISO is actively exploring this approach with stakeholders and plans to complete its conceptual design during the first quarter of 2017.⁸⁰³ The ISO also plans to expedite implementation efforts so that this approach is available as soon as possible. While the ISO develops and implements this enhancement, the ISO and ARB staff have agreed that a “bridging solution” starting in 2018 may be necessary to account for greenhouse gas emissions associated with secondary dispatches that may occur in connection with the dispatch of external resources that the ISO attributes as serving ISO load. Accordingly, the ISO supports, on an interim basis, ARB’s proposal to calculate emissions not currently captured by the EIM’s resource-specific attribution and retire allowances under its program. If the ISO can implement enhancements to its market optimization by January 1, 2018, it may be possible to forego the use of the bridging solution...

The ISO supports the use of a bridging solution on an interim basis to calculate emissions not captured by the EIM’s resource-specific attribution.

Among other changes in its 15 Day Notices, ARB proposes to apply a new emissions rate for EIM transfers that are considered electricity imports under ARB’s regulations. ARB proposes to calculate emissions for these transactions at the emissions rate for unspecified sources less emissions attributed to EIM participating resource scheduling coordinators by the ISO’s market optimization.⁸⁰⁴ Beginning January 1, 2018, ARB would retire current vintage allowances designated by ARB for auction, which remain unsold for more than 24 months, in the amount of the calculated outstanding emissions. This proposal constitutes “the bridging solution” the ISO has discussed with ARB staff.

While the ISO supports this bridging solution, ARB should only apply it on an interim basis in order to provide time for the ISO and its stakeholders to develop and implement enhancements to the market optimization to more accurately account for emissions associated with EIM transfers to serve ISO load.

The proposed bridging solution should include provisions allowing ARB not to apply the rule once the ISO implements these enhancements. The ISO urges ARB to articulate a process that will permit it to make the transition from the bridging solution as part of this rulemaking – possibly after certain conditions are met that the ISO and ARB could

⁸⁰² The term “secondary dispatch” refers to the effect of lower greenhouse gas emitting resources supporting EIM transfers to serve ISO load while higher greenhouse gas cost resources backfill to serve load in EIM Entities’ balancing authority areas. Secondary dispatch does not mean that the ISO market optimization has multiple distinct steps in dispatching resources to serve ISO load versus serving load in EIM balancing authority areas.

⁸⁰³ More information on the ISO’s stakeholder initiative is available on the ISO’s website: <http://www.caiso.com/informed/Pages/StakeholderProcesses/RegionalIntegrationEIMGreenhouseGasCompliance.aspx>

⁸⁰⁴ See proposed changes to cap-and-trade regulation in ARB’s 15 Day Notices at 17 California Code of Regulations Sections 95852.

memorialize in a memorandum of agreement. Once the ISO and stakeholders implement enhancements to the ISO market optimization, ARB should rely solely on resource-specific reported emissions as attributed by the ISO's market optimization.

When the ISO dispatches EIM resources to support a transfer to serve ISO load, the ISO seeks to minimize total costs associated with these transfers. As a result, the ISO attributes these EIM transfers to participating resources with the lowest economic bids (energy bid and greenhouse gas bid adder) based on available transmission. Least cost dispatch can have the effect of attributing transfers to serve ISO load to lower-emitting EIM resources because these resources face fewer or no costs to comply with ARB's regulations. In some instances, higher-emitting resources will need "to backfill" this dispatch to serve EIM load outside of the ISO.

In connection with its 15 Day Notices, ARB staff issued an analysis describing its concern that the current cap-and-trade and mandatory reporting regulations underaccount emissions associated with EIM transfers to serve California load.⁸⁰⁵ ARB also raises concerns that unaccounted emissions could increase as the EIM grows and as more transmission and a greater number of participating resources are available to support EIM transfers. ARB, however, makes no attempt to assess whether these additional resources and transmission capabilities will serve ISO load, or serve load with the EIM area outside of California. The former transactions are subject to ARB's regulations; the latter are not.

ARB staff explains that, notwithstanding the ISO's least cost dispatch market optimization, additional resources are likely operating as well to serve EIM and California load. Accordingly, ARB proposes to apply the unspecified source emissions rate to EIM transfers serving ISO load as a way to quantify these emissions. While this approach provides some comparability to how ARB accounts for emissions from unspecified sources, it overstates the emissions associated with EIM transfers to serve ISO load. In some intervals when an EIM transfer serving ISO load occurs, there is no secondary dispatch that could result in unaccounted emissions. For example, the ISO's market optimization may attribute an EIM transfer to a hydro resource that would not have operated except for California demand. Applying the unspecified source emission rate to this transaction over-states the atmospheric impacts of the EIM transfer serving California load. Nevertheless, the ISO supports ARB's proposal, subject to ARB's commitment that this approach is an interim bridging solution...

As part of its next 15 Day Notices in this rulemaking, ARB should acknowledge this effort [to implement the enhanced optimization] and develop a mechanism to apply the

⁸⁰⁵ See Attachment F to 15 Day Notices: Analysis of the Energy Imbalance Market and Mandatory Greenhouse Gas Reporting and Cap-and-Trade Regulations at 4-8.

<https://www.arb.ca.gov/regact/2016/capandtrade16/attachf.pdf>

results of the ISO's enhanced market optimization in its cap-and-trade and mandatory reporting regulations. (CAISO)

Comment:

Due to the complexity associated with implementation of the two-pass solution, City Light recognizes the need for an interim solution. City Light is cautiously supportive of CARB's proposal to account for the EIM "outstanding emissions" from EIM imports to California that are not currently accounted for in the dispatch algorithm. However, City Light requests that CARB clearly state the proposed accounting for "outstanding emissions" is an interim solution that will only be in place until CAISO's two-pass optimization is instituted... (SEACITYLIGHT)

Comment:

PGE is also supportive of the bridge or interim solution being proposed by CARB in the 15-day amendment text until the two-pass model is ready for use. This is the best option in the short term to accomplish CARB's goals without disrupting the broadly-beneficial and stable EIM dispatch algorithm or unduly burdening EIM participants. However, PGE requests that CARB add explicit language into the rule package that would remove the GHG accounting bridge solution once the CAISO two-pass model has been developed, tested and implemented. This would help prevent the delay of a rule and comment period once the two-pass model is ready to be implemented. If this is not possible, then PGE requests that CARB clearly indicate in this rule package that implementation of the bridge solution is temporary, and that CARB will propose further regulatory amendments to reflect the two-pass model once finalized. (PORTLANDGENELEC)

Comment:

While PacifiCorp continues to have concerns with respect to how emissions associated with energy imported into California via the EIM are identified and measured, PacifiCorp is supportive of the California Air Resources Board ("ARB") proposal to adopt an interim approach that may be applied outside of the EIM optimization. The adoption of an interim approach should enable the development of a long-term approach that is legally durable and less disruptive to the market. Adopting an interim approach should also allow more time for meaningful analysis and input from ARB, the California Independent System Operator ("ISO"), and stakeholders on these highly complex and challenging issues. (PACIFICORP)

Comment:

As part of the Cap-and-Trade Program and MRR draft regulations, ARB proposes an interim methodology to account for GHG emissions from the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM). ARB's proposal is intended to address its concern with inaccurate accounting of emissions attributable to secondary dispatches that happen as a result of primary dispatches to serve California

load. Notably, CAISO is working on a longer-term solution to address this. CAISO efforts have garnered a significant amount of stakeholder support and would adequately address ARB's concerns. While the CAISO solution cannot be implemented immediately, CAISO staff has recently estimated that it will be available as early as the end of 2018. CAISO is expected to release its draft final straw proposal this month to address its long-term solution and discuss the merits of an interim bridge solution as a result of stakeholder comments submitted last December...

It seems premature to enact regulations that establish an interim methodology to address this issue, given the timing of CAISO's work and the fact that the EIM is still in its infancy. As the EIM is still a relatively new construct in energy markets, the true extent of the possible GHG emissions underreporting is unknown. In fact, ARBs preliminary analysis points to an extremely small underreporting less than 0.1% of the overall program emissions.

The methodology being used seems to be inherently inaccurate and has the potential to significantly overestimate the GHG emissions associated with EIM transfers. The proposed reporting mechanism assumes that emissions from EIM transfers must equal the emissions that would have resulted if all transfers were considered as unspecified emissions. However, CAISO's analysis actually shows that EIM helps reduce grid-wide carbon emissions by facilitating efficient dispatch of renewable resources in support of clean energy policies while enhancing grid resiliency.

Before assigning a compliance obligation under the Cap-and-Trade Program, ARB should at least consider whether the applied unspecified emissions factor appropriately reflects the resource mix for units participating in the EIM, both for those opting to be deemed delivered to California and those in the overall EIM program. These are the only resources that would be available for imports into California or as secondary dispatch due to the EIM algorithm, and it is unlikely that the emission rate of generation controlled by these EIM entities exactly mirrors the emission rate of the entire western electric grid. To reflect improvements in this rate caused by expansion of the EIM, it should be regularly updated. Moreover, ARB should work with CAISO to fully evaluate the impacts of requiring EIM Participating Resource Scheduling Coordinators to report EIM transfers, as this could have an impact on future EIM participation. (SCPPA)

Comment:

However, the secondary emissions problem must be clearly defined, the GHG emissions costs and benefits of the proposed solution quantified, and the treatment of EIM emissions aligned with similar transactions for this solution to be implemented appropriately...

A. ARB Should Provide a Precise Definition of Emissions from Secondary Dispatch in Order to Ensure an Appropriate Solution

Developing an accurate approach to capturing secondary emissions requires a precise definition of what dispatch actions will be defined as secondary dispatch, and the circumstances under which emissions caused by secondary dispatch would require the surrender of ARB allowances. Criteria and considerations for designing and evaluating potential solutions will depend on the definitions adopted by ARB. In its most recent presentation to stakeholders, ARB stated that, “Secondary dispatch illustrates the potential backfill effect of higher emitting resources to serve EIM load when the optimization attributes lower emitting resources to serve California load.” The ARB presentation further notes that secondary dispatch is neither defined in the EIM tariff nor observable by market participants. Further defining secondary dispatch and the circumstances in which such emissions should be captured is an essential prerequisite to understanding the scope and magnitude of the issue, and implementing a reasonable remedy.

EIM currently assigns requirements for GHG allowances to resources deemed to provide imports into California to the cleaner resources scheduled in EIM. Under the proposed approach, ARB would retire additional GHG allowances using the unspecified emission rate for all imports scheduled into California by EIM. This does not directly calculate the emissions caused by the backfill effect and may overstate the emissions effect of EIM imports. While this would be an interim solution until CAISO can develop a more accurate method, it is still essential for ARB and CAISO to provide a clear definition of secondary dispatch and the circumstances in which such emissions should be captured.

B. The EIM Enables Significant GHG Reductions

PG&E interprets ARB’s objective as quantifying and pricing any emissions associated with secondary dispatch. However, it’s also important to keep in perspective that the EIM enables significant GHG reductions. For example, if it were not for the energy transfers facilitated by the EIM, some renewable generation in CAISO would have to be curtailed either through economic curtailment or exceptional dispatch. A recent CAISO report highlighted that for the first half of 2016, the EIM resulted in a reduction of 292,000 metric tons of GHG emissions...⁸⁰⁶

C. Creating Different Standards for the EIM and Specified Imports Could Weaken the EIM and Diminish its Benefits

PG&E shares the CAISO’s Department of Market Monitoring’s concern that the proposed solution for EIM holds the EIM to a higher GHG compliance standard than imports, and therefore will alter the incentives to participate in the EIM.⁸⁰⁷ By allocating additional secondary GHG compliance obligations to EIM participating resources, the

⁸⁰⁶ http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_JanJun_2016_.pdf

⁸⁰⁷ <https://www.caiso.com/Documents/DMMComments-RegionalIntegration-EIMGreenhouseGasComplianceStrawProposal.pdf>

current solution assigns a greater GHG compliance obligation to energy imported through EIM than energy imported from specified resources on a short-term basis. This could discourage EIM participation, which is concerning given that the EIM has lowered emissions and enabled California to export excess renewable generation as described above, resulting in not only GHG reductions but also cost savings (PG&E)

Comment:

Until such a time that the two-pass approach is in place, WPTF supports implementation of CARB's proposed interim solution. As we understand the interim solution, as of 2018, CARB will calculate the quantity of 'outstanding emissions' from EIM generation that are attributable electricity consumption in California, but not currently assigned to EIM imports via the EIM algorithm. These outstanding emissions will be determined by multiplying the total volume of EIM imports for an interval by the default emission rate and subtracting the quantity of emissions actually assigned by the EIM algorithm in that interval. CARB would then deduct a quantity of allowances equal to the outstanding emissions from the unsold allowances in the auction holding account.

We believe that CARB's proposed interim solution will more completely account for emissions associated with electricity consumption in California, while avoiding the distortionary market impacts of previous proposals. However, we request that CARB clearly indicate in the regulatory documents that implementation of this approach is intended to be temporary, and that staff will propose further regulatory amendments to reflect the EIM two-pass approach once finalized. (WPTF)

Comment:

In the December 21, 2016 proposed amendments, ARB proposes to adopt an interim "bridge" solution to account for emissions associated with energy imported into California via the EIM. The bridge solution, which essentially requires the retirement of allowances equivalent to EIM outstanding emissions reported by the ISO, is proposed to be put in place until a more permanent technical solution is developed by the ISO. The EIM Entities agree that in light of the potential market disruption associated with prior proposals, an interim solution that is conducted outside of the EIM optimization is appropriate. The adoption of this interim solution will allow time for ARB, the ISO, and stakeholders to develop a more robust and durable long-term approach. (EIMENTITIES)

Comment:

The proposed amendment offers an interim solution to account for GHG emissions within the Energy Imbalance Market footprint while the California Independent System Operator ("CAISO") develops new methods for GHG accounting. ARB proposes to utilize the unspecified electricity rate for all generation produced to serve California load that is served through the Energy Imbalance Market dynamic transfers rather than the resource specific electricity rate that is determined per the market optimization GHG

awards. This proposal would capture any generation that was increased outside of California to serve non-Californian load that is needed to replace any Energy Imbalance Market renewable production that was transferred to California. NV Energy believes this interim solution is a just and reasonable solution to address the potential emissions leakage within the Energy Imbalance Market. (NVENERGY)

Comment:

PSE generally supports the retirement of unsold allowances for EIM outstanding emissions. This provision is needed until the ISO is able to implement effective changes to the EIM market design to address ARB's concerns about GHG leakage. We base our support on the assumption that the ISO will be able to calculate and report EIM outstanding emissions as defined by ARB.⁸⁰⁸ (PUGETSNENERGY)

Comment:

As part of this coordination, LADWP urges ARB to reevaluate its position that it does not have authority to implement a solution that takes into account both emissions associated with secondary dispatch and emission reductions associated with reduced renewable curtailments facilitated by the EIM. (LADWP)

Comment:

Since this rulemaking began, there has been considerable debate regarding the extent to which the cap-and-trade program regulation needs to be amended to address CARB's concern that the GHG emissions from electricity transactions in the EIM are not being properly captured. CARB and CAISO assessments of the available data have provided differing perspectives on the scope of the issue, the magnitude of the impact, and the viability of various solutions. Further complicating this matter is the fact that the existing EIM is scheduled to expand in the near future and transactions in the EIM are expected to continue to grow in the coming years. This means that any changes CARB implements supported by data and assessments based on the currently limited scope of the EIM, will have far reaching and direct impacts on the growing EIM and the future of regional transactions. This is true regardless of whether the proposed modifications are intended to merely serve as an interim solution.

Furthermore, the proposal described in Attachment F may allow for more accurate accounting of the emissions experienced by the atmosphere, but it does not necessarily assign the compliance obligation to the appropriate entity. Rather, the solution should be market-based, resting solely on the generator responsible for the emissions and not apportioned statewide. The potential implications that the proposed approach would have on a greater number of transactions would compound this inequity, imposing additional costs where they are not warranted.

⁸⁰⁸ ARB, 15-day Amendment Text, Proposed Amendments to the California Cap on Greenhouse Gas Emission and Market-Based Compliance Mechanisms Regulation, p. 127.

CARB's proposal could also have unintended consequences for an expanded ISO. Even under the current scope of the EIM, the proposal essentially assigns a compliance obligation that is not directly linked to the responsible generator or importer of the emission. Using this basis as the precedent for a broader market is not sound policy, and should be avoided. M-S-R urges the Board to direct staff to continue to engage with the ISO and with stakeholders, and to develop a single, uniform solution that takes into account the magnitude of the potential leakage risk and the potential to impact the entire EIM. Until that solution is fully developed, including any necessary ISO tariff amendments, the current provisions for tracking GHG emissions in the EIM should be retained...

M-S-R believes that until such time as the CAISO has completed its review of the EIM program and GHG accounting, inclusive of effecting any necessary tariff amendments, CARB should retain the provisions regarding GHG accounting in the EIM unchanged. Despite the stated need for an interim solution, CARB's proposal does not include an end date, nor address how the process may be impacted by potential tariff amendments. A subsequent rulemaking to amend the regulation to incorporate changes necessitated by any tariff amendments could take months, during which time the interim solution would continue. This has the potential to cause disruptions to the market. (M-S-R)

Comment:

In the 15-Day Changes, CARB has proposed an "interim solution" to address the manner in which GHG emissions are accounted for in the CAISO EIM. Staff has identified concerns that the EIM optimization model may not account for all GHG emissions "experienced by the atmosphere as a consequence of electricity consumed in California."⁸⁰⁹ In Attachment F, CARB outlines its proposed solution to addressing GHG accounting. CARB recognizes that the CAISO has a stakeholder process that is also reviewing this matter and that tariff amendments are being considered. However, unwilling to wait for the process to be completed at the ISO, CARB has proposed an interim solution. NCPA is concerned that the interim solution, based on CARB's assessment, does not provide an accurate or fair means by which to assign the GHG cost burden, does not present a market-based solution, and may have unforeseen consequences for the expanding EIM. Rather than implement an interim solution of unspecified duration, CARB should continue forego revisions to the EIM GHG accounting metric until the CAISO process has been completed. In the interim, CARB and affected stakeholders should continue to work with the ISO on the proposed tariff changes to ensure that GHG emissions in the EIM are accounted for to the greatest extent feasible. (NCPA)

⁸⁰⁹ August 2, 2016 Staff Report p. 52.

Comment:

The interim solution for accounting for outstanding Energy Imbalance Market (EIM) emissions could be damaging to an expanded EIM and to future regional markets and should not be implemented. MID does not support the implementation of an interim solution to account for Outstanding EIM Emissions. The solution put forth by ARB in the 15 Day Changes, in which Outstanding EIM Emissions are reported by the CAISO and covered by allowances that were offered for auction from the state pool of allowances but remain unsold, is contrary to ARB's stated desire to pass a proper price signal to reduce emissions. By drawing from unsold allowances the effect will be an overall tightening of the cap, rather than a compliance obligation for the generators that are actually producing the emissions. Furthermore, MID cautions against allowing a temporary solution to affect the development and/or operation of the expanding EIM or more importantly, a potential expanded regional market. MID urges ARB to wait for the CAISO to complete their stakeholder process to create a market-based solution before addressing this issue in the regulation. (MODESTOID)

Comment:

ARB should refine the CAISO EIM GHG accounting proposal to consider the offsetting effects of renewable exports and inter-temporal netting. A recent focus on 'secondary emission effects' that result from the California Independent System Operator (CAISO) EIM optimization has led the ARB to propose a solution that does not properly weigh the GHG benefits of the EIM. On August 26, CAISO released a study demonstrating that the EIM dispatch actually displaced emitting generation for a net benefit to the atmosphere in the first half of 2016⁸¹⁰. In light of this information, Southern California Edison does not support the current method proposed in the regulation to quantify the scale of 'secondary emissions', as it would not take into account the emission reductions attributable to renewable exports. Netting the GHG benefits of EIM exports and imports would recognize the significant investment that California has made in renewable resources within the state, which when exported can reduce emissions outside of the state. Allowing netting over a reasonable period of time such as a year will allow EIM benefits to continue to accumulate at their maximum potential as they do today. While the SCE believes the proposed regulatory amendments to retire allowances to cover any 'secondary emissions' can be workable, we strongly believe the total compliance obligation should recognize the GHG benefits of renewable exports. (SOCALEDISON)

Response: Most of the comments related to accounting of GHG emissions associated with imported electricity under EIM are addressed in response to 45-day comment D-2.1. Please refer to those comments and response for additional information.

⁸¹⁰ http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ3_2016.pdf

Also see staff's response to 45-day comment D-2.1 for why staff declines to incorporate consideration of exported EIM electricity to revise GHG accounting for EIM imports, as well as clarification that PRSCs without deemed resources are not required to report to ARB.

Regarding comments on revising the Regulation to reflect CAISO's proposed two-pass solution, please also see response to 45-day comment D-2.1.

Regarding CAISO's suggestion that ARB and CAISO should enter into a memorandum of agreement, ARB welcomes the opportunity to continue working collaboratively with CAISO to improve emissions accounting and reporting. If CAISO finalizes the two pass market optimization, ARB will consider appropriate regulatory changes to align its regulations with such improvements. ARB is focused on ensuring that the Cap-and-Trade Regulation operates well when accounting for EIM transactions, and appreciates CAISO's offer to collaborate more closely. At this time, an ongoing subpoena and regular conversations at the staff level support this work. Staff will explore whether a formal memorandum of agreement is needed as the CAISO EIM revision process becomes more mature and as this collaboration continues.

For comments related to ARB's analysis released as Attachment F to the 15-day amendment package, please see response to comment D-2.4 in this section of the document below.

D-2.2. Multiple Comments:

California Independent System Operator (CAISO) Energy Imbalance Market (EIM) Secondary Emissions Effect – PG&E generally supports ARB's proposed interim approach to address secondary emissions from the EIM...

PG&E has questions and concerns regarding two aspects of implementation of the proposal. Firstly, the proposed regulations do not specify which, if any, allowances ARB would retire in the event that there are not sufficient unsold allowances in the Auction Holding Account for more than 24-months to cover the EIM Outstanding Emissions. (PG&E)

Comment:

Further consideration is needed to determine the effects of the proposal on allowance supply and pricing. ARB proposes to account for the outstanding EIM GHG emissions by retiring unsold allowances in the auction account. If this approach is an interim solution, offhand, it appears that the auction account would not be depleted; however, retirement of allowances may raise the price of allowances as the supply diminishes and will reduce the number of allowances that would have gone to the Allowance Price Containment Reserve. ARB has not provided information on how this proposal would impact allowance supply and prices and the proposal leaves substantial uncertainty

regarding what would occur if there are insufficient unsold allowances to cover the calculated outstanding EIM GHG emissions. (SCPPA)

Comment:

ARB proposes to account for the "outstanding EIM GHG emissions" by retiring unsold allowances in the auction account. If this approach is an interim solution, offhand, it appears that the auction account would not be depleted; however, retirement of allowances may raise the price of allowances as the supply diminishes and will reduce the number of allowances that would have gone to the Allowance Price Containment Reserve. ARB has not provided information on how this proposal would impact allowance supply and prices and the proposal leaves substantial uncertainty regarding what would occur if there is insufficient unsold allowances to cover the calculated outstanding EIM GHG emissions. Answers to these important issues are essential to the development of an accurate and effective methodology to account for GHG emissions for electricity imported through the EIM. (LADWP)

Response: Commenters are concerned that the Proposed Amendments could result in insufficient unsold allowances being available to satisfy EIM Outstanding Emissions. Commenters are also concerned that the new compliance obligation of the EIM Outstanding Emissions will result in allowance supply impacts, and allowance prices could increase as unsold allowances are retired to account for EIM Outstanding Emissions as opposed to being diverted to the APCR.

Regarding insufficient unsold allowances to satisfy EIM Outstanding Emissions, ARB staff believes there will be sufficient unsold allowances to meet EIM compliance obligations under the bridge solution. Staff will monitor whether sending allowances that remained unsold for 24 months to the APCR could result in a shortage of unsold allowances with which to meet EIM compliance obligations, and intends to withhold unsold allowances to satisfy the expected compliance obligation of future EIM outstanding emissions, consistent with the regulatory provisions intended to ensure the EIM outstanding emissions are met.

With respect to allowance supply impacts and price effects, the EIM-related amendments do not affect allowance supply. Allowance supply was set at the onset of the Program by annual economy-wide emissions caps that decrease over time and cover in-state electricity emissions, as well as the emissions associated with imported electricity that serves California load. Instead, the EIM-related amendments correct allowance demand. Staff determined that inaccurate accounting is currently resulting in an incorrect measurement of the allowance demand for emissions associated with EIM imports to serve California load. See staff's responses to 45-day comments D-2.1 and first 15-day comment D-2.5 for more detail on this determination. The amendments correct the artificially low allowance demand associated with EIM through the implementation of the bridge solution (via retirement of EIM outstanding

emissions). This change aligns the Program with the intended goals of AB 32, including that “greenhouse gas emissions reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board.”⁸¹¹

D-2.3. Comment:

The Washington State Department of Ecology (Ecology) has implemented the Clean Air Rule, which took effect on January 1, 2017. This rule covers air emissions from PSE’s gas-fired generating plants and places a compliance obligation on those emissions at the source. PSE typically makes our gas-fired generating plants available for dispatch in the EIM, including for import to California. As a result of the Ecology rule, PSE incurs compliance obligations in Washington State and California when our gas-fired plants are dispatched into the ISO.

The ARB rules allow for reduction of compliance obligations for linked programs.⁸¹² However, the Ecology program is not linked to the ARB program, and thus the ARB regulations do not allow for the exemption of compliance obligations for electricity imported from Washington State. Because the EIM footprint extends into several other western states, this dual compliance obligation could occur if and when other states also adopt GHG compliance programs (carbon tax and cap-and-trade programs have also been considered in Oregon). This creates a situation of inequitable treatment to resources in certain states that participate in the EIM because power imported to California from Washington State, for example, (or other states in the future) will have an added cost from double GHG accounting and overlapping GHG compliance programs.

PSE proposes that ARB modify the CO₂e_{covered} equation⁸¹³ to include the reduction of compliance obligations covered by another state. We suggest creating a new term, CO₂e_{other-state}, that would be defined as annual metric tons of CO₂e with a compliance obligation covered by another state with a GHG reduction program. This new term would be subtracted from the total amount of CO₂e_{covered}. This solution would work in the EIM, as well as in a regional ISO market should it be implemented.
(PUGETSNDENRGY)

Comment

Secondly, as currently proposed, the calculation of EIM Outstanding Emissions is based on all EIM energy transfers into California and does not make any adjustments for emissions that are accounted for under another GHG emissions trading system (ETS). PG&E is concerned that this would be a disincentive to EIM participation for entities in regions that develop a GHG ETS, including GHG ETSs with linkages to ARB’s Cap-

⁸¹¹ Health & Safety Code, § 38562(d)(1).

⁸¹² ARB, 15-day Amendment Text, Proposed Amendments to the California Cap on Greenhouse Gas Emission and Market-Based Compliance Mechanisms Regulation, p. 282.

⁸¹³ Ibid at p. 126

and-Trade Program. As noted elsewhere in these comments, both the EIM and the ARB Cap-and-Trade linkages provide valuable avenues for emissions reduction. For this reason, PG&E recommends that ARB amend the proposed EIM Outstanding Emissions calculation to exclude EIM energy transfers from regions with their own GHG ETS. (PG&E)

Response: Commenters request staff implement a mechanism by which the emissions associated with electricity from a state with its own ETS are accounted for in the Cap-and-Trade Regulation, either by decreasing covered emissions by the amount of emissions that are covered by another state's ETS or by excluding EIM electricity deliveries from the definition of EIM Outstanding Emissions if such electricity is delivered from a jurisdiction with its own ETS. Please see response to 45-day comment D-2.2.

D-2.4. Multiple Comments:

As noted above, the EIM Entities support the adoption of the proposed bridge solution as a way to satisfy ARB's concerns regarding emissions leakage in EIM as well as to allow sufficient time for the development of a more permanent and durable solution. That being said, the EIM Entities also believe that ARB's analysis that seeks to quantify EIM emissions leakage is misleading. Simply applying a default emission factor to all zero-emitting EIM transfers into California, as ARB does in Attachment F: Analysis of the Energy Imbalance Market and Mandatory Greenhouse Gas Reporting and Cap-and-Trade Regulations, is not an accurate reflection of emissions leakage actually occurring in the EIM, if leakage in the EIM is occurring at all.

ARB concludes that undercounting occurs when the greenhouse gas attribution is attached to a different specific resource than the resource in an EIM balancing authority for which actual electricity was dispatched and physically transferred to California. However, ARB staff's quantification seems to assume that this occurs in every instance where the EIM optimization identifies a zero-emitting resource as deemed delivered to California. This is over-simplified. ARB's analysis seems to assume that all EIM transfers into California are from emitting resources when in fact the current EIM footprint includes a diverse mix of generating resources, many of which are zero-emitting, that are co-optimized to meet demand across the entire EIM including California. If ARB was to use this flawed analysis, the results could be perceived as demonstrating that the EIM has somehow increased overall greenhouse gas emissions. However, it would be counterintuitive to conclude that the EIM has not produced significant environmental benefits when the data clearly shows that EIM is allowing solar oversupply to avoid curtailment by displacing thermal generation outside California and that EIM's wide-area load and resource diversity is both reducing overall ramping requirements and providing zero-emitting ramping resource alternatives. As noted above, the ISO calculates in the first three quarters of 2016 that EIM dispatch reduced GHG emissions in the footprint by 143,695 metric tons. While the EIM Entities understand accounting for these impacts is challenging, the EIM Entities request that

ARB clarify these points in future analyses, and attempt to refine the model to better fit the known resource mix and actual dispatch of EIM. (EIMENTITIES)

Comment:

As noted above, PSE supports the adoption of the proposed bridge solution as a way to satisfy ARB's concerns regarding emissions leakage in EIM as well as allow sufficient time for the development of a more permanent and durable solution. However, we found that the ARB analysis of leakage in the EIM⁸¹⁴ was not based on ISO reported emissions from secondary dispatch supporting imports to California. Although ARB concluded in its analysis that "EIM imported electricity specified resource attribution is underreported to ARB by 43.8 percent over a 12-month period relative to unspecified source electricity,"⁸¹⁵ ARB's conclusion is based on a calculation of emissions using the default emission factor of 0.428 MTCO₂e/MWh applied to EIM electricity imports of zero-emitting resources. This overestimates the amount of leakage in the EIM because the ISO has shown that EIM transfers to California do not always create a secondary dispatch.⁸¹⁶

It would be helpful if ARB would clarify this approach in future analyses, as well as work with the ISO to evaluate the percentage of imports of zero-emitting resources that are associated with secondary dispatch.

PSE also asks that ARB provide an opportunity for the ISO to review and comment on future analyses of the EIM so that it most accurately represents EIM market dispatch and operations. (PUGETSNDENRGY)

Comment:

As noted above, PacifiCorp appreciates ARB staff's publication of an analysis paper that begins to clearly articulate ARB's specific concerns with the existing EIM optimization and deemed delivery approach. Though PacifiCorp is supportive of ARB's proposed interim approach given the complexity of the issues involved, PacifiCorp has some concern with ARB's conclusions regarding underreported EIM emissions in the EIM. ARB staff ultimately concludes that undercounting occurs when the greenhouse gas attribution is attached to a different specified resource than the resource in an EIM balancing authority area from which actual electricity was dispatched and physically transferred to California. However, ARB staff's quantification seems to assume that this occurs in every instance where the EIM optimization identifies a zero-emitting resource as deemed delivered to California. In other words, it assumes in all cases where, for

⁸¹⁴ State of California Air Resources Board, Analysis of the Energy Imbalance Market and Mandatory Greenhouse Gas Reporting and Cap-and-Trade Regulation, Release Date December 21, 2016.

⁸¹⁵ Ibid at p. 1

⁸¹⁶ ISO Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw

Proposal Conference Call, Slide Deck p. 9-13. http://www.caiso.com/Documents/Agenda-PresentationRegionalIntegration-EIMGreenhouseGasCompliance-Dec1_2016.pdf

example, PacifiCorp's hydro resources were deemed delivered to California, that California load was actually served by a marginal gas resource. The reality is likely more complicated: certainly in some instances California load is actually served by zero-emitting resources. It is therefore not necessarily the case that underreported emissions are even occurring in the EIM. Regardless, this overly simplified assumption likely overstates any quantity of underreported emissions.

PacifiCorp is concerned with this approach and potential overstatement of underreported emissions because it presents a potentially misleading view of the overall environmental impact of the EIM. The EIM has, and continues to have, an overall positive environmental impact by enabling the greater integration of variable renewable resources. In part due to its participation in the EIM, PacifiCorp's overall 2016 carbon emissions from owned resources decreased by 11 percent as compared to an average of the last five years. This reduction is based on actual monitored data at PacifiCorp's generating resources and does not involve any complex accounting and attribution assumptions. The environmental benefits associated with the EIM are likely to increase as more entities join and are able to more effectively integrate renewable generation on their systems. Though PacifiCorp understands ARB's concern with respect to its accounting methodology, the emissions identified as underreported are a specific function of ARB's accounting methodology and California's regulatory framework and does not reflect an assessment of the overall emissions impact of the EIM.

PacifiCorp urges ARB staff to consider the opportunities presented by the EIM for California to increasingly rely on zero-emitting resources to serve its load and to displace emitting resources outside of California. PacifiCorp continues to object to ARB staff's characterization of its objective as capturing all emissions experienced by the atmosphere as a result of electricity imported to serve California load while simultaneously discounting or ignoring emissions reductions experienced by the atmosphere from zero-emitting electricity exports. PacifiCorp is concerned that ARB's analysis may be perceived as an overall assessment of the emissions impacts of the EIM and requests that ARB clarify that this is not the case. (PACIFICORP)

Comment:

CMUA believes it is likely that the Staff Analysis overstates the impact of the CAISO's deemed delivered mechanism on emissions from EIM imports. It seems logical that lower-than-system-average emitting resources would seek to sell to California, given their competitive advantage against California resources that have cap-and-trade obligations. Moreover, it seems likely that calculation of this effect could differ greatly among subregions of the West and, further, among subregions of the EIM footprint, depending on resource portfolios of the participants and hydrological conditions in the particular year or season. In fact, it is easy to envision EIM optimization being dominated by hydroelectric dispatch in many intervals, particularly in average or above average hydro years, irrespective of any carbon policy overlay...

Third, CMUA questions the validity of the assumption that expanded EIM participation will mean an increasing problem with EIM Outstanding Emissions. Indeed, this is almost certainly wrong. The addition of NV Energy was driven by its own portfolio and level of transmission connectivity with both California and the PacifiCorp East Balancing Authority Area. This presented a particular set of facts because of NV Energy's robust transmission connectivity to both California and PacifiCorp, and its thermal dominated portfolio. Other future EIM Entities have hydro dominated portfolios, and little or no direct transfer capability into California. As such, these entities will increase the amount of zero emission resources competing to serve California load over the same amount of transmission transfer capability, and will likely lower the overall emissions because their marginal costs will be below thermal resources and they will displace those resources within the EIM optimization. (CALMUNIUTILASSOC)

Comment:

ARB's Proposed California Independent System Operator Energy Imbalance Market GHG Accounting and Reporting Methodology

ARB is proposing an interim "bridge" solution to account for the GHG emissions associated with California Independent System Operator Energy Imbalance Market (CAISO EIM) electricity imported into California. ARB states that it is concerned that zero or low-emission generation that had been supplying load outside California is being dispatched by the EIM algorithm into California and other higher-emitting fossil generation is used to backfill the zero- or low-emission generation. This scenario would result in the discharge of more GHG emissions in the atmosphere...

ARB's proposal seeks to quantify the "...outstanding EIM GHG emissions" that ARB believes are unaccounted for by taking the difference between the total gross electricity imported into California through the EIM using the unspecified source emission factor (marginal grid mix for the western electric grid) and emissions associated with specified source imports reported by CAISO under the current methodology. That is, under this proposal, ARB assumes (not, as it asserts, demonstrates) that the true emissions associated with all electricity imported through the EIM are either generated by a marginal unit or are redispatched and backfilled by a marginal unit, and so, on average carry the unspecified emission rate. One implication of this approach is that by attributing all EIM imports with emissions at the unspecified rate, ARB, by assumption, treats the EIM as having no impact on grid-wide emissions. This assumption does not comport with the nature and purpose of the EIM. As CAISO analysis has demonstrated, the EIM helps reduce grid-wide carbon emissions by facilitating the efficient dispatch of renewable resources in support of clean energy policies while enhancing grid resiliency.

The assumption that, on average, electricity imported through the EIM carries emissions at the unspecified rate also is not consistent with ARB's policy that GHG emissions reports are accurate. To the extent ARB continues with its current proposed approach, it should calculate the marginal emission rate based on the grid-mix of EIM participating

entities and not the entire western regional grid. These are the only resources that would be available for imports into California as secondary dispatch due to the EIM algorithm, and it is unlikely that the emission rate of generation controlled by these EIM entities exactly mirrors the emission rate of the entire western electric grid. To reflect improvements in this rate caused by the EIM, it should be regularly updated.

ARB is justifying its proposal based on limited data (one year of data from one EIM entity). LADWP believes that the proposed bridge solution is premature and likely overestimates GHG emissions; ARB should continue to work with CAISO to develop accounting solutions based on CAISO's principles.⁸¹⁷ (LADWP)

Comment:

PG&E is also concerned with ARB staff conclusions that increased participation in the EIM leads to additional EIM leakage. On page 12 of Attachment F, ARB staff conclude that as a result of increased EIM participation and the deemed-delivered mechanism in the EIM algorithm that attributes delivery to the lowest emitting resources, there is a growing potential for emissions leakage as the EIM expands. PG&E believes further analysis is needed prior to reaching this conclusion. Additionally, as secondary dispatched resources can either be zero-emitting resource or fossil fuel-based resource (and could be correlated with the marginal units in the EIM Balancing Authority), further analyses is warranted as to which EIM entities are correlated to an increase in emissions leakage. (PG&E)

Response: Some commenters express appreciation for staff's analysis, and the increased clarification of staff's concerns with the current EIM algorithm. Staff thanks them for their support. Two core results of the analysis, as stated in the conclusion of Attachment F, are that:

[b]ased on staff's analysis there is a trend towards a growing quantity of electricity being deemed delivered to serve load in California through the EIM as more transmission is available to satisfy California load imbalances with out-of-state generation. There is also a trend towards an increased percentage of deemed delivered electricity being attributed to zero-emitting resources as a greater quantity of zero-emitting generation is available to be deemed within each market interval. Both of these trends indicate a growing potential for emissions leakage as the EIM market continues to expand and include additional EIM entities such as Arizona Public Service and Puget Sound Energy.⁸¹⁸

⁸¹⁷ California Independent System Operator Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal, November 17, 2016

⁸¹⁸ December 21, 2016. "Attachment F: Analysis of the Energy Imbalance Market and Mandatory Greenhouse Gas Reporting and Cap-and-Trade Regulations"
<https://www.arb.ca.gov/regact/2016/capandtrade16/attachf.pdf>

Some commenters express doubts that “backfill” emissions that support cleaner generation routed to serve California load are generators that, on average, emit at the default emissions rate. Based on ARB’s understanding of the EIM algorithm, the interim bridge outstanding emissions rate (i.e., assuming backfill resources have emissions that are on average at the default emissions factor), reasonably and conservatively captures GHG emissions from EIM market operations, pending further improvements to the EIM algorithm.

A commenter asserts that ARB’s conclusions are driven by the particular circumstances of NV Energy’s generation profile and proximity to California. Specifically, the commenter says that ARB has concluded that any increase in EIM imports attributable to EIM transfers from NV Energy would necessarily come from higher emitting resources based on the unique circumstance of NV Energy’s thermally-dominated portfolio.

The commenter misunderstands how the EIM optimization currently works. Direct transfer capability is not a requirement for the EIM algorithm to deem a resource as having served California load. The full output (i.e., base schedule and incremental generation if applicable) of the low- or zero-emitting resources would be eligible to be deemed as serving California EIM imports regardless of physical transfers on transmission lines connecting California to the new EIM entrant.

Some commenters highlight that the EIM GHG underreporting identified by the EIM analysis is either small or may not increase as new balancing authority areas join the EIM, and use this to justify waiting until the completion of the revised two pass solution. Delaying improved GHG accounting, however, would be at odds with ARB’s mandate under AB 32 to account for all emissions from electricity consumed in California and minimize emissions leakage. See also response to 45-day comment D-2.1.

D-2.5. Multiple Comments:

The ISO has proposed to modify how the optimization will attribute EIM transfers to EIM participating resources in order to address concerns that the current dispatch may not accurately capture secondary emissions associated with an EIM transfer to serve California load.⁸¹⁹ The ISO proposes to run its least cost dispatch optimization in two steps. First, the ISO proposes to identify the least cost dispatch of resources to serve EIM load without allowing transfers to serve ISO load. This step will provide an economic base of resource schedules outside California from which the ISO can then identify incremental dispatches to serve ISO load. Second, the ISO will run its least

⁸¹⁹ See ISO Straw Proposal dated November 17, 2016 issued in Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement initiative. <http://www.caiso.com/Documents/StrawProposal-RegionalIntegrationEIMGreenhouseGasCompliance.pdf>

cost dispatch optimization allowing transfers to serve California load. The ISO will attribute those transfers to output from resources above these resources' economic base schedules identified in the first step. This approach will effectively ensure no secondary dispatch will occur as a result of dispatching a lower emitting resources to serve ISO load. Under the proposed enhancements, the ISO's least cost dispatch optimization will first identify the most economic resources serving EIM external load before attributing output to EIM resources for transfers to serve ISO load.... (CAISO)

Comment:

City Light recognizes the importance of accounting for the atmospheric effects of the CAISO's least cost dispatch attributable to California load, and supports CAISO's development of the two-pass market optimization as a long-term solution. The proposed two-pass optimization will result in a more accurate accounting of GHG emissions attributable to California, while also preserving the resource-specific cost and GHG attribution components within the optimization. Importantly, this approach also provides for price signals that meaningfully represent the value of low- or zero-emitting resources and/or resources located outside of California in the CAISO-administered markets. (SEACITYLIGHT)

Comment:

PGE supports CAISO's "Option 2" – modify the ISO optimization to attribute transfers to resources that are incrementally dispatched and maintain resource-specific cost and attribution (also known as the twopass model) – as the long-term, sustainable solution for EIM GHG accounting. PGE submitted comments on CAISO's *Regional Integration – California's Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal* ("Straw Proposal") on December 15, 2016 stating our support for the two-pass model... (PORTLANDGENELEC)

Comment

WPTF has agreed with CARB concerns that the way the EIM is currently dispatching and assigning generation to CAISO load is distorting dispatch and, in some cases results, in increased emissions in the combined CAISO/EIM footprint. To address this concern, we have supported consideration of modifications to how EIM algorithm treats carbon costs in the dispatch and allocation of generation to serve CAISO load.

WPTF considers that the so-called 'two-pass' approach being developed by the California Independent System Operator (CAISO) offers an appropriate long-term solution to resolve the current EIM GHG accounting problems. This approach would restrict the eligibility of a resource's output to be deemed delivered to California to incremental generation above a counterfactual economic dispatch optimized for the EIM footprint without transfer to California. To the extent that low-cost, zero-emissions resources are dispatched in the first economic-base run, output of these resources would be attributed to non-California load and thus not available to displace California

generation. This would result in gas generation (both California and external) being considered more often for attribution to California, compared to the current EIM algorithm.

We recognize that CAISO has a number of details to work out with respect to implementation of the approach, and that changes to the algorithm will necessitate approval by the Federal Energy Regulatory Commission. However, we are optimistic that the design details can be resolved, and the approach approved and implemented by 2018 (WPTF)

Comment:

After CARB raised concerns regarding GHG compliance under the EIM design, the California Independent System Operator Corp. (“CAISO”) embarked on a stakeholder process to explore potential solutions to ensure accurate GHG accounting in the EIM. As part of that process, CAISO is currently in the process of finalizing the preferred “two-pass” approach that emerged from the stakeholder process.⁸²⁰ Powerex is optimistic that, once implemented, the two-pass solution will ensure that the EIM accurately recognizes the GHG emissions from out-of-state resources dispatched to serve California load, avoiding all of the unintended consequences identified above. (POWEREX)

Comment:

In prior comments to the ARB and to the California Independent System Operator (“CAISO”), CMUA provided principles that should guide the development of any regulation seeking to address greenhouse gas (“GHG”) emissions associated with the Energy Imbalance Market (“EIM”).⁸²¹ First among those principles was that any solution should accurately include carbon costs in the market optimization, so that these carbon costs are incorporated into the market and modify participant behavior accordingly. In this regard, we have indicated our preference for the two-pass “Option 2” outlined by the CAISO that attempts to include carbon costs in the overall optimization while reflecting the reality that not all resources within the EIM footprint will have Cap-and-Trade compliance obligations. (CALMUNIUTILASSOC)

Response: Commenters express unanimous support for development and implementation of CAISO’s two-pass solution. CAISO is still in the process of developing amendments to its EIM tariff and replacing its underlying GHG tracking system (i.e., implementing the two-pass solution). However, these

⁸²⁰ See Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement – Straw Proposal (Nov. 17, 2016), available at <https://www.caiso.com/Documents/StrawProposal-RegionalIntegration-EIMGreenhouseGasCompliance.pdf>

⁸²¹ See, e.g., Comments of the California Municipal Utilities Association on the October 21, 2016 Mandatory GHG Reporting and Cap-and-Trade Program Workshop, Nov. 4, 2016.

proposed changes are still being developed and will not be in place during data year 2017, and potentially not during reporting year 2018. ARB supports further development of CAISO's two-pass market optimization approach to provide a rigorous accounting framework, which is designed to more accurately reflect GHG emissions from serving California load than the current EIM GHG award methodology. ARB will consider and propose any necessary amendments to the Cap-and-Trade Regulation after the two-pass solution is finalized.

Miscellaneous

D-2.6. Comment:

II. Proposed New Compliance Rules for EIM Imported Electricity

The ARB Staff's proposed amendments introduce a new compliance and reporting approach for EIM imported electricity. While the proposed new approach would not change the current reporting requirements for EIM participating resource scheduling coordinators pursuant to the Mandatory Reporting of Greenhouse Gas Emissions (MRR), the new approach would require the California Independent System Operator (CAISO) to report information regarding EIM imported electricity that is used to serve California load annually. ARB would use the information provided by CAISO to calculate the "outstanding emissions." Staff defines "EIM Outstanding Emissions" as:

*"equal to the annual metric tons of CO₂e from electricity that is imported into California through CAISO's EIM but not otherwise accounted for by emissions reported by the EIM participating resource scheduling coordinators. These emissions are calculated pursuant to the requirements in MRR section 95111(h)(1)."*⁸²²

The proposed approach would act as a bridge to support accurate accounting from EIM market operations while a long-term approach is being developed by CAISO⁸²³. Staff stated that "this data can then be used to appropriately determine compliance obligations in the Cap-and-Trade Regulation."⁸²⁴ Staff indicated that the interim solution and the longer term solution are both necessary because the CAISO's current EIM model does not capture and report the full quantity of GHG emissions that result from imports that serve California load.

Section 95852(b)(1)(D) of the proposed amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation

⁸²² Attachment A, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, p. 127.

<https://www.arb.ca.gov/regact/2016/capandtrade16/attacha.pdf>

⁸²³ Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information, p. 12. <https://www.arb.ca.gov/regact/2016/capandtrade16/15daynotice.pdf>.

⁸²⁴ Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information, p. 12. <https://www.arb.ca.gov/regact/2016/capandtrade16/15daynotice.pdf>.

regulations⁸²⁵ includes additional provisions that would direct some unsold allowances to the Retirement Account to fully account for emissions from electricity imported through the CAISO EIM to “ensure environmental and market integrity of the Program.”⁸²⁶

MRR Section 95111 (h) (1) and Section 95111 (h) (2) of the proposed modifications to the MRR regulations, contain the following proposed bridge solution reporting requirements for EIM imported electricity.⁸²⁷

(h) Reporting requirements for Imported Electricity in the Energy Imbalance Market (EIM):

(1) Calculation of EIM Outstanding Emissions. Each year after the verification deadline in section 95103(f), ARB will calculate “EIM Outstanding Emissions” using information reported annually by CAISO and Participating Resource Scheduling Coordinators with imported electricity in EIM. Annual information reported by CAISO and Participating Resource Scheduling Coordinators must be based on data for each 5- minute interval:

(A) “EIM Outstanding emissions” equals “Total California EIM Emissions” less “Deemed Delivered EIM Emissions” associated with electricity imported by EIM

Participating Resource Scheduling Coordinators deemed delivered to California by the EIM optimization model.

Where “Total California EIM Emissions” equals the amount of emissions calculated by CAISO pursuant to section 95111(h)(1)(B).

(B) *Calculating Total California EIM Emissions.* Annually, based on each 5-minute interval, CAISO must calculate, report and cause to be verified, the CO₂equivalent mass emissions associated with imported electricity in EIM using the following equation:

$$\text{CO}_2\text{e} = \text{MWh} \times \text{EF}_{\text{unsp}} \times \text{TL}^{828}$$

⁸²⁵ Refer to page 127-128 of Attachment A, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, <https://www.arb.ca.gov/regact/2016/capandtrade16/attacha.pdf>.

⁸²⁶ Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information, p. 13. <https://www.arb.ca.gov/regact/2016/capandtrade16/15daynotice.pdf>.

⁸²⁷ Attachment A, PROPOSED AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS, pp.A-98 to A-99. <https://www.arb.ca.gov/regact/2016/ghg2016/attacha.pdf>.

⁸²⁸ Where: CO₂e = CO₂ equivalent mass emissions from Total California EIM electricity (MT of CO₂e); MWh = Megawatt-hours of EIM imports identified by CAISO to serve California load. EF_{unsp} = 0.428 MT of CO₂e/MWh; and TL = 1.02 (transmission loss factor). Attachment A, PROPOSED AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS, p. A-98. <https://www.arb.ca.gov/regact/2016/ghg2016/attacha.pdf>.

(C) *Deemed Delivered EIM Emissions*. Annually, based on each 5-minute interval, each EIM Participating Resource Scheduling Coordinator must calculate, report, and cause to be verified, emissions associated with electricity imported as deemed delivered to California by the EIM optimization model.

(2) Annually, CAISO will report, and cause to be verified, the following information:⁸²⁹

(A) Annual State-Wide Total for EIM Imports and Exports. Total annual imports and exports into and out of California in MWh, consistent with the results of the EIM optimization based on Real-Time Dispatch (RTD), and associated with (1) Total California EIM Emissions, and (2) Deemed Delivered EIM Emissions;

(B) Annual State-Wide Total for EIM Imports by Entity. Total annual imports into California in MWh, consistent with the results of the EIM optimization model based on Real-Time Dispatch (RTD), and associated with (1) Total California EIM Emissions, and (2) Deemed Delivered emissions, for each Participating Resource Scheduling Coordinator (PRSC) and for CAISO;

(C) Annual State-Wide Total for EIM Exports. Report total annual exports out of California in MWh, consistent with the results of the EIM optimization model based on Real-Time Dispatch (RTD), for each Participating Resource Scheduling Coordinator (PRSC) and for CAISO.

ORA submits the following questions regarding the proposed bridge solution for EIM imports:

1. Please clarify when and for how long the Staff bridge solution will take effect?
2. Would the proposed new approach for EIM imports impact the compliance obligations of covered entities? If the answer is yes, how would the covered entities reconcile the variance in compliance obligations resulting from the proposed new approach for EIM imports with their current compliance obligations?...
3. Would the CAISO's proposed long-term solution for accurate accounting for EIM market operations result in different compliance obligations of covered entities as compared to the ARB's proposed bridge solution? If the answer is yes, how would the covered entities reconcile the variance in compliance obligations for under the ARB's proposed bridge solution with the compliance obligations under the CAISO's proposed long-term solution?
4. What is the definition of "Deemed Delivered EIM Emissions"?
5. Please clarify how ARB defines Real-Time Dispatch in terms of intervals?

⁸²⁹ Attachment A, PROPOSED AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS, p. A-99.
<https://www.arb.ca.gov/regact/2016/ghg2016/attacha.pdf>

6. How does ARB intend to use the proposed amendments in Section 95111 (h) (2) [subsections (A), (B) and (C)] of the MRR regulations?
7. Is the intent of the proposed bridge solution to determine annual EIM Outstanding Emissions by entity or for California in total?
8. In the proposed amendments to the MRR regulation in Section 95111 (h) (2) (B), please clarify how the Annual State-Wide Total for EIM Imports by Entity would be calculated?
9. In the proposed amendments to the MRR regulation in Section 95111 (h) (2) (A) and Section 95111 (h) (B), please clarify the difference between Annual State-Wide Total for EIM Imports in Section 95111 (h) (2) (A), and Annual State-Wide Total for EIM Imports... “for CAISO” in Section 95111 (h) (2) (B).
10. For the proposed amendments to the MRR regulation in Section 95111 (h) (2) (A) and (B), please clarify the difference between Annual State-Wide Total for EIM Exports in Section 95111 (h) (2) (A), and Annual State-Wide Total for EIM Exports... “for CAISO” in Section 95111 (h) (2) (B).
11. The proposed amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation in Section 95852(b)(1)(D) would retire some unsold allowances in the Auction Holding Account in the amount of EIM Outstanding Emissions. Please clarify if ARB is proposing to retire unsold allowances by the amount of California total EIM Outstanding Emissions, or retiring unsold allowances proportional to each entity’s EIM Outstanding Emissions, and please provide the rationale for proposing that method?
12. Public Utilities Code (PUC) Section 399.16, of the Renewable Portfolio Standards (RPS) statute identifies the electricity products that are eligible to comply with the RPS procurement requirements, including portfolio content category 2 (PCC2 or bucket 2), which allows for incremental electricity and substitute energy when procuring renewable resources.⁸³⁰ Do the proposed amendments treat emissions resulting from eligible imports under PCC2, as unaccounted for, and therefore include them in EIM Outstanding Emissions?

If the answer is yes, ORA disagrees with ARB’s proposed inclusion of such imports within “EIM Outstanding Emissions,” because the RPS rules consider the entire output of a renewable energy facility covered by firmed and shaped contracts as renewable energy delivered to California.⁸³¹ In this situation, after paying a renewable premium for Renewable Energy Credits (RECs) in compliance with the RPS program, any importing

⁸³⁰ Under RPS rules, one of the portfolio content categories of eligible renewable energy resources, as defined in PU Code 399.16 (b) (2) is: “Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California Balancing Authority.”

⁸³¹ Refer to CEC Guidebook, Renewable Portfolio Standard Eligibility, 3rd ed., January 2008.

<http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF>.

utility (and therefore its ratepayers) would still be obligated to pay GHG compliance costs for renewable energy pursuant to ARB proposed rules.

If ARB proposes to include emissions resulting from eligible imports under PCC2 within “EIM Outstanding Emissions,” ORA recommends that ARB develop a mechanism to distinguish emissions associated with PCC2 imports from other unaccounted for emissions due to EIM imports. (OFFICERATEPAYERADVCT)

Response: The commenter’s questions relate specifically to changes being proposed in MRR, and are addressed in response F-12 of the 2017 FSOR for the Mandatory Greenhouse Gas Reporting Regulation.

D-2.7. Comment:

In its December 21, 2016 package ARB has proposed further changes to how it accounts for energy transfers from adjacent states so as to accurately represent the carbon associated with electricity imported into California. VEA is supportive of the CAISO’s proposed algorithmic changes which hold the possibility of a more equitable treatment of electricity flows into and out of California across through neighboring participating regions. CARB’s proposed cap and trade changes will not provide a resolution to disparities that are created for VEA by CARB’s treatment of the balancing energy that is used to balance VEA’s Nevada load.

CARB seems to have implicitly declined other proposed remedies offered by VEA given that no related changes have been proposed in any of the draft policy changes recommended. VEA is disappointed that CARB has been unwilling to address VEA’s concerns – concerns that are recognized as legitimate by the CAISO. (VEA’s September 2016 comments outlined these issues and proposed remedies in detail and attached herein.)

VEA urges CARB to continue to work with the CAISO to implement algorithmic changes that both resolve the EIM issue and provide a model accurate treatment of any regions that participate in the CAISO energy markets yet are located outside the state of California. In the interim VEA again asks CARB to be responsive to VEA’s requests to address the failure of the cap and trade rules and practices to properly account for the impact of VEA’s balancing energy on California carbon. (VALLEYELECTRIC)

Response: See staff’s response to 45-day comment D-2.3.

D-2.8. Comment:

ARB also should eliminate the proposal for the ISO to become a reporting entity under ARB’s mandatory reporting regulation. ARB has not justified the need to make the ISO a reporting entity. Other, less burdensome, methods exist for ARB to obtain the information to verify data reported by emitting entities covered under ARB’s regulations...

ARB should eliminate its proposal to make the ISO a reporting entity under its regulations.

ARB's 15 Day Notices continue to propose that the ISO become a reporting entity under the mandatory reporting regulation for purposes of the EIM.⁸³² ARB has not justified the need for this change. Other, less burdensome, methods exist for ARB to obtain information necessary to verify data that is reported by emitting entities covered under ARB's regulations. Under the California Global Warming solutions Act of 2006 (AB 32), ARB has the authority to require reporting from greenhouse gas emission sources.⁸³³ The ISO is a market operator and transmission planning entity. In conducting these activities, the ISO is not a source of emissions under AB 32. Although the ISO may have possession of market data that may assist ARB in implementing its regulations according to AB 32, however, the ISO is not the appropriate reporting entity under ARB's regulations.⁸³⁴

ARB's regulations must be reasonably calculated to meet its statutory directive.⁸³⁵ There must be substantial evidence supporting ARB's determination that the regulation is reasonably necessary to effect AB 32.⁸³⁶ Earlier in this rulemaking, ARB asserted that it needed additional data from the ISO to ensure an accounting of greenhouse gas emissions.^{837 838 839} However, ARB already receives all of the data associated with EIM transfers to serve California load from EIM participating resource scheduling coordinators.⁸⁴⁰ These entities report quantities of EIM transfers attributed to its resources to serve California for each five-minute dispatch period. In order to calculate emissions under the bridging solution ARB has proposed, ARB can add reported data from EIM participating resource scheduling coordinators to determine the total EIM transfers in any given five-minute interval. ARB can then apply the emission rate for unspecified sources to this quantity.

ARB does not explain why it cannot use existing processes – including its subpoena authority – to obtain ISO market data for electricity imports that occur through the EIM. The ISO is not a reporting entity for other electricity imports that use ISO market processes to serve California load. Instead, ARB regulations apply to entities that appear on an e-Tag as the purchasing-selling entity on the last segment of the tag's

⁸³² See proposed changes to 17 CCR Section 95111(h).

⁸³³ California Health and Safety Code Section 38530(b)(1).

⁸³⁴ California Government Code Section 11342 requires ARB's proposed regulations to be consistent with its authority under AB 32.

⁸³⁵ California Government Code Sections 11342 and 11349.

⁸³⁶ *Id.* at Section 11350.

⁸³⁷ ARB Staff Report: Initial Statement of Reasons at 9.

<https://www.arb.ca.gov/regact/2016/ghg2016/ghgisor.pdf>

⁸³⁸ CCR Section 95111.

⁸³⁹ CCR Section 95802(a)(122).

⁸⁴⁰ CCR Section 95111.

physical path with the point of receipt located outside of California and the point of delivery located inside California.⁸⁴¹ ARB validates this information through a subpoena it has issued to the ISO and other balancing authorities operating in California. The ISO supports using this same model in the case of electricity imports that occur through the EIM. ARB should obtain information from electricity importers and subpoena data from the ISO, if necessary. To do otherwise would create inconsistent reporting formats for information under ARB's regulations.

In fact, ARB has already issued a standing subpoena to the ISO for EIM transaction data.⁸⁴² The ISO is willing to explain the steps it takes to collect responsive information to this subpoena as part of its affidavit of custodian of records. If appropriate, the ISO is also willing to enter into a memorandum of agreement with ARB to ensure that it has access to appropriate information to support the accurate accounting of emission associated with electricity imports. Such an agreement may also be useful to document how ARB plans to transition from the use of the proposed bridging solution described in its 15 Day Notices to the use of a resource-specific attribution of transfers based on the enhancements the ISO plans to make to its market optimization.

ARB should eliminate its proposal to require reporting emissions of electricity exported from California through the EIM.

As part of its 15 Day Notices, ARB has also proposed to make the ISO a reporting entity for EIM transfers that constitute electricity exports.⁸⁴³ The ISO objects to this proposal for two reasons. First, the ISO does not need to be a reporting entity for ARB to obtain information about the total quantities of EIM transfers out of the ISO to serve load outside of California. The ISO makes this information available on its public open access same time information website. If necessary, ARB can also subpoena this information from the ISO. Second, the ISO's optimization does not attribute dispatches from participating resources that support EIM transfers from the ISO to serve EIM load.

In its assessment of benefits arising from the western EIM, the ISO prepares a quarterly benefits information report. This report quantifies the amount of avoided renewable energy curtailment in California realized through the use of the EIM. This report also estimates the amount of greenhouse gas emission reductions based on the fact that the ISO can transfer renewable output to external balancing authority areas using five-minute dynamic transfers that it may otherwise need to curtail. This output displaces production from external conventional resources. However, the ISO's report does not identify specific resources that support these EIM transfers. ARB's proposal would require the ISO to report emissions associated with EIM transfers without adequate

⁸⁴¹ CCR Section 95802(a)(122).

⁸⁴² <http://www.caiso.com/Documents/2015-04-01CaliforniaAirResourcesBoardSubpoena.PDF>

⁸⁴³ See proposed changes to mandatory reporting regulation at 17CCR Section 95111 (h).

guidance as to what emissions rate the ISO should apply. This proposed requirement lacks clarity and ARB should eliminate it as part of its next 15 Day Notices.⁸⁴⁴ (CAISO)

Response: The CAISO reporting provisions raised by the commenter are outside the scope for this Cap-and-Trade rulemaking as those provisions are in the Mandatory Reporting Regulation. This issue is addressed in the 2017 FSOR for the Mandatory Greenhouse Gas Reporting Regulation. Regardless, ARB staff notes here that, in the second 15-day amendment package for MRR, staff removed CAISO as a reporting entity under MRR and instead will receive the necessary information from CAISO through an annual subpoena process.

D-2.9. Multiple Comments:

ARB should eliminate its proposed changes to its cap-and-trade that exclude EIM transactions from the resource shuffling safe harbor provisions. This language creates uncertainty for entities subject to ARB's regulation and is inconsistent with other language in ARB's regulation relating to resource shuffling...

ARB's proposal to modify the safe harbor provisions associated with the prohibition against resource shuffling creates uncertainty and is internally inconsistent.

In its 15 Day Notices, ARB has not changed its earlier proposal to modify the safe harbor provisions associated with the prohibition against resource shuffling. These proposed changes exclude EIM transactions from the list of transactions that ARB has clarified do not constitute resource shuffling.^{845 846}

As the ISO explained in comments submitted last year in this rulemaking, this proposed change creates uncertainty and it creates an internal inconsistency in ARB's cap-and-trade regulation. First, the proposed language creates uncertainty because it suggests that economic bids or self-schedules that clear the ISO's real-time market constitute resource shuffling when they do not. Resource shuffling, as defined by ARB, is a "plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation."⁹ ISO market dispatches do not meet this definition because they are not a plan, scheme or artifice undertaken by a first deliverer of electricity. The proposed language signals to an entity participating the EIM that it may face compliance risks associated with the prohibition against resource shuffling. Second, the proposed regulatory changes are internally inconsistent because they state that electricity imported through the EIM is not exempted from resource shuffling provisions. However, ARB's regulations maintains a

⁸⁴⁴ California Government Code Section 11349 requires that ARB's draft its proposed regulations so that the meaning of regulations will be easily understood by those persons directly affected by them.

⁸⁴⁵ See proposed changes to cap-and-trade regulation at 17 CRR Section 95852(2)(a)(10).

⁸⁴⁶ CRR Section 95802(a)(336).

safe harbor from the prohibition against resource shuffling for ISO real-time market transactions.⁸⁴⁷ The EIM is the ISO's real-time market extended to other balancing authority areas in the West. ARB should eliminate the proposed language in the cap-and-trade regulation that excludes EIM transactions from the resource shuffling safe harbor provisions. (CAISO)

Comment:

Additionally, City Light encourages CARB to include the EIM in the resource shuffling safe harbor. EIM resources are dispatched per the EIM algorithm. EIM entities do not determine how resources are dispatched, and should not be subject to penalties for activity that they have no control over. Thus, City Light requests that CARB revise its proposed regulation to remove the proposed language excluding the EIM from the resource shuffling safe harbor. (SEACITYLIGHT)

Comment:

PGE submitted comments to CARB on September 19, 2016, on their *Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation*. In those comments, PGE opposed the removal of the safe harbor for short term transactions (including EIM transactions) with regard to resource shuffling. PGE continues to assert that the existing resource shuffling exemption for short-term sales is appropriate given the nature of the short-term and EIM markets. PGE disagrees with CARB's retention of the language in this proposed rule package that would eliminate the current resource shuffling safe-harbor for EIM imports. This change introduces an unacceptable level of compliance risk for EIM participants that cannot be effectively mitigated and therefore may result in reduced market participation. EIM participants have little control over the ultimate real-time resource dispatch in the EIM; the proposed change opens the possibility for an EIM participant to inadvertently and unintentionally violate the resource-shuffling requirements. CARB staff has indicated that this change to the resource shuffling requirements was proposed as a placeholder while the EIM greenhouse ("GHG") accounting concerns were addressed. Given that appropriate intermediate and long-term solutions have been identified (see our comments below), CARB should remove this placeholder and retain the current resource shuffling safe harbor for short-term transactions. (PORTLANDGENELEC)

Comment:

PacifiCorp continues to have significant concerns regarding the proposed exclusion of EIM from the resource shuffling safe harbor. As noted in earlier comments, entities participating in the EIM only control whether, and at what price, to allow resources to participate in the EIM. EIM entities have no control over how resources are dispatched

⁸⁴⁷ California Government Code Section 11349 requires that proposed regulations do not conflict with or are not contradictory to existing law.

in the EIM or how resources are deemed delivered to California. While EIM entities may designate specific resources as unavailable to be deemed delivered to California (thereby reducing or avoiding a compliance obligation under the Cap-and-Trade Program), EIM participants cannot know or unilaterally direct whether or which resources may be substituted for resources unavailable for delivery to California. ARB should not penalize, or threaten to penalize, entities for activity over which they have no control. To do so is to make participation in EIM an act of resource shuffling, an outcome that would have a significant chilling effect on market participation.

Moreover, ARB has provided no guidance or information regarding its view on how resource shuffling may occur in the EIM. Nor has ARB provided any rationale for the adoption of an illogical policy that excludes transactions of less than 12 months in duration but *includes* transactions occurring every five minutes. As with the short-term bilateral market, rational market behavior in the EIM is essentially indistinguishable from a specific plan, scheme, or artifice to reduce a compliance obligation through substituting resources. As PacifiCorp has noted in prior comments, from a market perspective, all else being equal, California's policy creates an incentive for the import of cleaner resources. The current EIM optimization reflects this incentive by solving to lower the total cost—in part through lowering the overall compliance obligation. The Cap-and-Trade Program introduces a cost to the market which the market is, by design, incentivized to reduce.

Though ARB staff indicates that it anticipates that it may withdraw the proposed modification to the safe harbor provision in a future 15-day notice package, this is not sufficient assurance for entities participating in the EIM, or considering participation in the EIM, who may face significant penalty exposure for activities over which they have no control and/or activity that reflects rational market behavior. The specter of *any* penalties is likely to create an unacceptable level of regulatory risk for many entities, including PacifiCorp. Since penalty exposure may be unavoidable, the only available alternative to remove this risk may be to discontinue participation in the EIM altogether. Given the significant financial and environmental benefits being realized through the EIM, this outcome should be avoided.

PacifiCorp understands that ARB staff's intent may be to highlight this issue as one for discussion and further the understanding by all parties regarding how the EIM works. PacifiCorp fully acknowledges that these issues are complicated and PacifiCorp is more than willing to work through them with ARB staff and other stakeholders. However, assuming this is an accurate reflection of ARB staff's intent, opening an important dialogue by perfunctorily excluding the EIM from the resource shuffling safe harbor without explanation is fundamentally inappropriate and unfair. Proposing to expose entities to significant penalties for behavior that may be entirely out of their control is not the best way to begin an important and complex policy and technical conversation. This approach immediately puts regulated entities in a position which is defensive rather than constructive and makes reaching an effective solution more difficult.

With this 15-day package, ARB has released an analysis of the EIM and is starting to articulate its specific concerns with the existing EIM optimization. This information is very helpful: PacifiCorp appreciates this additional information and context presenting ARB staff's perspective. However, this analysis does not address resource shuffling or identify specific concerns regarding exactly how resource shuffling may be occurring or could occur in the EIM. As opposed to proposing to exclude the EIM from the resource shuffling safe harbor without explanation, ARB staff should first articulate its specific concern. At that point, parties may weigh in on whether or not such exclusion is likely to address the concern identified or whether there may be other less disruptive methods that would address the concern. Given the foregoing, PacifiCorp urges ARB to withdraw the proposed exclusion of EIM from the resource shuffling safe harbor and instead engage with stakeholders to identify its specific concerns and work constructively toward effective solutions. (PACIFICORP)

Comment:

Lastly, WPTF strongly objects to CARB's retention of language proposed in the 45-day package that would exempt EIM imports from the resource shuffling safe-harbors. As WPTF has previously stated, the assignment of EIM dispatch to California load is a function of the EIM algorithm and market conditions – not the actions of EIM participating resources. It would be completely inappropriate to potentially subject EIM participating resources to resource shuffling accusations for EIM market results that are out of the control of market participants.

CARB staff have previously indicated that such language was proposed solely as a place holder until the EIM GHG accounting concerns could be addressed. Given that an appropriate intermediate and longterm solutions have been identified, CARB should eliminate the language exempting EIM imports from resource shuffling safe harbors. (WPTF)

Comment:

ARB should not exclude EIM from the resource shuffling safe harbor. In the December 21, 2016 proposed amendments, ARB continues its proposal to exclude EIM from the resource shuffling safe harbor without any additional explanation or articulation of how it believes resource shuffling may be a concern in the EIM. The EIM Entities are very concerned with this approach: entities participating in the EIM do not control how resources are dispatched or how they are deemed to be delivered to California. Participating entities are therefore unable to reduce a compliance obligation by substituting one source for another—they cannot shuffle their resources. Though ARB has articulated vague concerns regarding emissions leakage in EIM, ARB has not articulated specific concerns with respect to how resource shuffling is or may be occurring in EIM. ARB should not penalize, or threaten to penalize, entities for activity over which they have no control without further explaining its specific concerns.

Though ARB staff indicates that it anticipates that it may withdraw the proposed modification to the safe harbor provision in a future 15-day notice package, this is not sufficient assurance for entities participating in EIM, or considering participation in the EIM, who may face significant penalty exposure for activities over which they have no control. The specter of such penalties, however remote, may create an unacceptable level of regulatory risk for many entities and has the potential to stifle the growth of the EIM. As noted above, the EIM is producing significant financial and environmental benefits. At a bare minimum, ARB should not introduce this level of regulatory uncertainty and risk into this well-functioning and beneficial market without significantly more information regarding its concerns and/or guidance to market participants as to how to avoid penalty exposure. As such, at this time, no proposal that removes EIM transactions from the resource shuffling safe harbor should be under consideration by ARB. (EIMENTITIES)

Comment:

In the 15 day rulemaking package, CARB indicates that it has not modified its initial proposal to modify CTR § 95852(b)(2)(A)(10) by adding language that “Electricity imported through the CAISO EIM market is not exempted from resource shuffling provisions.”⁸⁴⁸ CARB staff “anticipate that the amendments now being proposed to the regulation, along with those that may be proposed in subsequent notice packages, and via anticipated changes to the CAISO tariff, will ultimately address this issue.” In other words, it appears that the proposed language would be removed if and when CAISO implements the two-pass solution, providing further encouragement for prompt implementation.

Powerex strongly supports CARB’s efforts to ensure that the EIM properly treats GHG emissions in a manner that fully complies with both the letter and the intent of California’s Cap-and-Trade program. Powerex has consistently advocated for robust GHG treatment in the EIM, including in its comments during 2013 (when the EIM design was being developed), its FERC filings in 2014 (when the CAISO tariff amendments to implement the EIM were submitted to the agency), and in its 2016 comments in both CAISO’s stakeholder process and CARB’s rulemaking proceedings.

However, Powerex does not believe that adopting the proposed language regarding resource shuffling and the EIM is an effective way to ensure timely implementation of the two-pass solution in the EIM. As a practical matter, proceeding with the proposed language may create uncertainty for out-of-state EIM participants regarding the implications of the proposed language, even though the inaccurate treatment of GHG emissions is solely the result of how the EIM algorithm is designed. Specifically, a resource that submits a bid into the EIM does not control whether the EIM algorithm deems its output as serving California load, nor does it even control whether the

⁸⁴⁸ CTR § 95852(b)(2)(A)(10) also adds “(except EIM)” to its existing rule that bids that clear the CAISO day-ahead or real-time market do not constitute resource shuffling.

resource is dispatched at all. Not only does it seem to be unfair to create this uncertainty for EIM participants considering that the outcomes are the result of the current EIM algorithm, there seems to be nothing that EIM participants could do to avoid the uncertainty that would be created by the proposed rule except to avoid EIM participation altogether.⁸⁴⁹

The solution to the adverse GHG-related outcomes arising from the current EIM algorithm is to modify that algorithm. Creating new regulatory uncertainty for EIM participants—which are not in charge of the EIM algorithm or its modifications—may do little to encourage timely implementation of a two-pass solution. Moreover, the uncertainty created by the proposed rule may materially discourage EIM participation, and undermine the other benefits of that market.

Powerex strongly urges CARB to remove the proposed update to § 95852(b)(2)(A)(10). As discussed previously, Powerex believes there are far more appropriate and effective steps that CARB can take to ensure the timely implementation of a robust two-pass solution in the EIM. (POWEREX)

Comment:

CMUA is particularly concerned and confused by the removal of EIM transactions from the exemption from resource shuffling prohibitions. EIM is simply an extension of the CAISO's Real Time Market. What is proposed in the 15-Day Modifications is not based on any supporting rationale and CMUA cannot envision a logical distinction between two California utilities, for example, where one is within the traditional CAISO footprint and submitting bids into the Real Time Market, where another similarly situated entity may also be within California and in the same real time optimization, but as an EIM Entity. CMUA urges that this distinction be removed and the proposed amended language be eliminated. (CALMUNIUTILASSOC)

Comment:

D. ARB Should Maintain the Resource Shuffling Safe Harbor for EIM Participants

The interim measure proposed in the ARB 15-day notice package and the permanent measures being discussed in the CAISO Regional GHG Initiative would address ARB concerns about assigning GHG obligations for “leakage” emissions. Therefore, removing the resource shuffling safe harbor provision is not necessary to achieve the objective of accounting for these emissions.

PG&E is concerned that removing this exemption could create regulatory confusion and discourage EIM participation. Specifically, resource shuffling prohibitions apply to the “First Deliverer of Electricity,” which in this case would be the EIM Participating

⁸⁴⁹ Conceivably, EIM participants could inform CAISO, through their bids, that they are unwilling for their output to be deemed delivered to California. However, this would have the same practical effect on California consumers as if those out-of-state resources abandoned EIM participation entirely.

Resource Scheduling Coordinator, including resources that have not elected to export energy to California.

However, the obligation for “leakage” emissions would be fulfilled through a process of CAISO reporting EIM transfers to ARB and ARB retiring allowances based on the information provided by CAISO. In this way, there is a mismatch between the entity whose actions could be deemed resource shuffling and the entity that would ensure that EIM Outstanding Emissions are accounted for. PG&E believes this creates unnecessary regulatory confusion, and recommends reinstating the resource shuffling safe harbor. (PG&E)

Response: Staff reinstated the EIM resource shuffling safe harbor in the 2nd 15-day package. See staff’s response to the 45-day comment D-2.5.

D-3. Renewable Portfolio Standard (RPS) Adjustment

D-3.1. Multiple Comments:

Retaining the RPS adjustment is much appreciated, but further changes would strengthen the value, accuracy, and administration of the provision. MID strongly supports that the 15-Day Changes eliminate language that would have discontinued the RPS adjustment post-2020. The RPS adjustment provision protects our ratepayers from millions of dollars in compliance costs for investments in firmed-and-shaped renewable energy contracts that were made prior to the inception of the Cap-and-Trade program. There are, however, additional changes that could be made to the regulation that would ensure that our ratepayers receive the full value of their investment, increase the accuracy of the ARB’s emissions reporting, and make it easier than before for the ARB to implement and enforce the RPS adjustment provision. For the full details, please refer to the comments submitted by the utilities, including MID, that are most impacted by this provision, titled “Utility Recommendations to Improve Implementation of the Renewable Portfolio Standard Adjustment Under the Cap-and-Trade Program” submitted on January 20, 2017. Our proposal to enhance the RPS adjustment consists of three complementary components:

1. Revise Section 95852(b)(4)(D) of the Cap-and-Trade regulation to exclude RPS adjustment claims for specified imports rather than directly delivered electricity. Double-counting of zero-emission benefits only occurs when energy is imported by one entity as a specified import and another entity claims an RPS adjustment for that same energy. A specified import is easy to track and the EDU that originally purchased the renewable energy and is entitled to the RPS adjustment or the Generation Providing Entity (GPE) has reasonable control over what energy is sold as a specified product. As the regulation is currently written, any energy produced by the renewable resource, whether sold as specified or unspecified, that sinks (i.e. is directly delivered) to California cannot be claimed as an RPS adjustment. This is a much higher bar and the GPE or EDU have little control over direct deliveries, which occur in much greater amounts than specified imports. The existing language also has negative implications for emissions

accounting. In an instance where the GPE sells unspecified energy from the renewable resource to a third party (unspecified because the EDU originally purchased the emissions attribute) and directly delivers the energy to California as an unspecified import, the ARB would record twice the amount of emissions than it should (the original EDU's redelivered energy at the unspecified rate plus the unspecified energy imported by the third party from the renewable facility). One of those entities should receive the zero-emission benefit of the energy, and it should be the EDU that paid for that benefit. It is important to note that in the current regulation, electricity must be directly delivered in order to be specified, but directly delivered electricity can be unspecified.

2. ARB would provide a supplemental allocation equivalent to any RPS adjustment within a reporting year that the EDU is unable to claim. This supplemental allocation would be based on actual, verified data and would ensure that our ratepayers receive the full benefit of their investments. EDUs claiming an RPS adjustment would lag their claim by one year so that the ARB could provide a report showing any specified imports of electricity from renewable resources for which the EDU is claiming an RPS adjustment. Such a comparison would allow for easier identification of improper specified import claims.

3. Retain the requirement in Section 95852(b)(3)(D) of the Cap-and-Trade regulation and verify REC serial numbers for quality control. By virtue of how the energy market actually operates, all purchases of specified renewable energy should be accompanied by a transfer of RECs. By retaining the requirement for importers of specified renewable energy to report REC serial numbers, ARB would retain an invaluable tool for verifying the correctness of claims of both specified renewable energy and RPS adjustments. The Mandatory Reporting Regulation (MRR) staff need only sum for each renewable facility: RECs attributed to specified imports and RECs associated with RPS adjustment claims. If the resulting sum exceeds the total facility generation, then some entity made an improper specified source claim; that entity will be the one claiming a specified renewable import without the RECs to back up its claim.

Since this proposal is linked with, and provides some benefit to, MRR staff, MID requests that ARB ensure that MRR staff reviews this proposal. If ARB does not accept this proposal and retains the direct delivery interpretation of the regulation, MID ratepayers would be excluded from claiming RPS adjustment for approximately 30-50% of the output of our renewable energy facilities for which we have firmed-and-shaped contracts. These contracts, grandfathered in the RPS program, extend past 2030 and currently comprise over 40% of MID's total RPS portfolio. (MODESTOID)

Comment:

RPS Adjustment. SCPPA thanks staff for its acknowledgement of concerns previously raised by utilities with respect to the RPS Adjustment. The decision to maintain the provision is a critical one for SCPPA Members as it safeguards against undue cost

exposure and helps align the Program with other state energy policies and goals that are helping California achieve overarching climate change goals.

Nonetheless, SCPPA continues to have concerns with the treatment of directly delivered resources in light of staff's unease over potential double-counting issues related to the misreporting of "null" power. SCPPA believes that a workable solution exists and has collaborated with the Joint Utility Group ("JUG") to develop comments submitted on this matter. We look forward to continuing discussions with ARB Staff and other members of the JUG. (SCPPA)

Comment:

Thank you for the opportunity to comment on the proposed amendments to the cap-and-trade regulation. The following nine utilities are jointly submitting these comments on the Renewable Portfolio Standard (RPS) adjustment: Los Angeles Department of Water and Power, Modesto Irrigation District, M-S-R Public Power Agency,⁸⁵⁰ Pacific Gas and Electric Company, Sacramento Municipal Utility District, San Diego Gas & Electric Company, Southern California Edison Company, Southern California Public Power Authority, and Turlock Irrigation District.

We recommend that the California Air Resources Board (ARB) take the following three complementary actions to improve implementation of the RPS adjustment. These three complementary actions avoid double counting, improve workability, and protect California electricity consumers from unexpected cap-and-trade compliance costs for their substantial investments in renewable electricity generated outside of California.

Action 1: Revise Section 95852(b)(4)(D) of the Cap-and-Trade Regulation to Replace "Directly Delivered" with "Claimed as a Specified Import"

Currently the cap-and-trade regulation prohibits the RPS adjustment from being claimed when electricity from an eligible renewable energy resource is directly delivered to California. This is too broad and should be narrowed. This will address ARB Staff's concerns about double counting the zero emission attribute of electricity produced by a renewable generating facility between specified imported electricity and the RPS adjustment.

We propose that ARB revise Section 95852(b)(4)(D) of the cap-and-trade regulation as follows:

(D) No RPS adjustment may be claimed for the portion of electricity from an eligible renewable energy resource when its electricity is that is claimed as a specified import directly delivered.

⁸⁵⁰ 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.

We propose this revision for the following reasons:

- The potential for double counting of the zero emission attribute exists only when directly delivered electricity meets all the requirements to be claimed as specified. The zero emission factor cannot be claimed for directly delivered electricity that was purchased as unspecified. Therefore, Section 95852(b)(4)(D) should be narrowed to only electricity that is claimed as specified rather than all electricity that is directly delivered.
- The revision aligns with the contract-based framework used in ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions to differentiate specified from unspecified electricity. To claim imported electricity from a renewable generating facility as specified with a zero emission factor, the electricity must be directly delivered from the generating facility into California either by a Generation Providing Entity (GPE) or a purchaser whose contract specifies the renewable generating facility as the source. Directly delivered electricity from the same facility that was purchased as unspecified electricity on an exchange cannot be claimed as specified with a zero emission factor because it does not satisfy the specified source contract requirement.
- The revision improves the workability of the RPS adjustment provision by narrowing the scope of the search criteria. To avoid double counting the zero emission attribute, reporting entities should only have to look for electricity that can be claimed as a specified import rather than every e-tag that originates from the renewable generating facility.

Action 2: Allocate Supplemental Allowances to Compensate for RPS Adjustment Credits that a Utility Has Been Unable to Claim

If an Electrical Distribution Utility (EDU) that owns Portfolio Content Category 2

(PCC2) or Portfolio Content Category 0 (PCC0) (i.e., grandfathered) renewable energy credits (RECs) associated with a contract for firmed and shaped RPS eligible electricity was unable to claim the RPS adjustment credit, then ARB should provide the EDU with a supplemental allocation of allowances. This will protect California electricity customers from unexpected cap-and-trade compliance costs for the RPS eligible electricity. This should occur regardless of whether another entity claimed electricity from the renewable generating facility as a specified import or the EDU was unable to satisfy the burden of proof under the RPS adjustment guidance.

We propose a supplemental allocation for the following reasons:

- The original allocation of allowances to EDUs for protection of California electricity customers assumed that all RPS eligible electricity would be treated as zero emission for cap-and-trade compliance purposes. The RPS adjustment implements that policy decision by providing a credit to reduce the cap-and-trade compliance obligation for firmed and shaped RPS eligible electricity that is not

directly delivered. If an EDU was unable to claim the RPS adjustment credit to reduce its cap-and-trade compliance obligation, then the EDU will incur cap-and-trade compliance costs that were not anticipated when ARB determined the original allocation of allowances to the EDU.

- The supplemental allocation for the unclaimed RPS adjustment is similar in concept to the true-up allocation that provides industrial entities additional allowances to account for changes in production or allocation not properly accounted for in prior allocations. The supplemental allocation for the unclaimed RPS adjustment should be a one-for-one allocation without any discounts to ensure that the supplemental allocation is equivalent to what the EDU would have received had it been allowed to claim the RPS adjustment.
- The supplemental allocation for the unclaimed RPS adjustment would work as follows: An Electric Power Entity (EPE) would use a new “unclaimed RPS adjustment” tab added to the EPE reporting spreadsheet (Workbook 1) to report PCC2 or PCC0 RECs for firmed and shaped RPS-eligible electricity that could not be claimed for the RPS adjustment. The verifier would check this data and review the documentation as part of verifying the annual EPE report. The number of allowances needed for the supplemental allocation would be calculated as the quantity of RECs on the “unclaimed RPS adjustment” tab multiplied by the emissions factor for unspecified electricity, which is the same way that the RPS adjustment would have been calculated. The allowances for the supplemental allocation would come from the pot of state-owned allowances. The supplemental allocation would be provided to the EDU along with its normal allocation of allowances in October.
- ARB should continue to provide EDUs with the flexibility to “bank” and claim the RPS adjustment at a later date, after the RECs have been retired for RPS compliance. We would like to meet with ARB Staff about the mechanics and timing for integrating a supplemental allocation into the process.

Action 3: Retain the Requirement in Section 95852(b)(3)(D) of the Cap-and-Trade

Regulation to Report and Verify REC Serial Numbers for Quality Control

We believe that ARB should retain the requirement to report and verify REC serial numbers under Section 95852(b)(3)(D) of the cap-and-trade regulation for the following reasons:

- The REC serial number data is necessary for quality control by ARB to verify claims of specified source imports and the RPS adjustment and to ensure no double counting.
- The REC serial number information is essential for proper accounting of zero emission renewable electricity. There is one and only one REC issued for each megawatt hour (MWh) of electricity produced by a renewable generating facility,

so review of the REC data is essential to ensure that each MWh is counted only once. If the requirement to report and verify REC data for specified imports is deleted, ARB will not have the information necessary to perform a quality control check on specified imports of electricity from renewable generating facilities.

Thank you for your consideration of these comments, and for the ongoing opportunities to provide input on strengthening the cap-and-trade program. (9UTILITIES)

Comment:

TID supports the retention of the RPS adjustment provision. This is extremely important for TID, as a major part of our RPS compliance is tied to the 2009 purchase of the Tuolumne Wind Project located in Washington. The retention of the RPS adjustment is an example of Staff harmonizing RPS with Cap & Trade as directed by AB 32. As stated in the 2010 Final Statement of Reasons (FSOR) (p. 57), "The RPS adjustment provision accomplishes the purpose of reducing a deliverer's compliance obligation by accounting for renewable imports"...

The proposed removal of the REC serial number reporting requirement will undermine California ratepayers' investments in out of state renewables by sending a signal to the market place that "null power" can be purchased and delivered at a zero emissions factor even though the importing entity did not purchase the RECs, which include all "green attributes". The term Green Attributes is defined in the WREGIS Operating Rules to include the emissions attributes of renewable resources. By not recognizing green attributes in the MRR and instead allowing null power to be reported as zero emissions power, the ARB has created a fundamental inconsistency between the RPS and the Cap-and-Trade. The ARB's regulations allow null power to be reported as zero emissions power, effectively transferring one of the key benefits of California ratepayers' renewable energy benefits to market participants that acquire the null power. The ARB should not send this market signal. Instead, the ARB should require that null power be reported as unspecified, or at a bare minimum, retain the REC serial number reporting requirement and require a non-conformance finding when an entity does not report REC serial numbers.

We are concerned that the removal of the REC serial number requirement will exacerbate the direct delivery concerns the ARB has faced in implementing the RPS adjustment requirements. Without the REC serial numbers, the ARB will not be able to distinguish between those entities that directly delivered null power from all of the other entities that imported Procurement Content Category 1. By retaining the REC serial number reporting requirement, the ARB will have a list of entities with non-conformances and this information could be used to confirm or bolster RPS adjustment claims and allow for a more in-depth assessment of when there may have been direct delivery and when there was not direct delivery. (TURLOCKID)

Comment:**III. RPS Adjustment**

LADWP, as part of the California Joint Utilities Group (JUG), supports JUG's comments and proposals to provide a workable solution to address the potential double counting issue and protect California electricity consumers from unexpected cap-and-trade compliance costs for their substantial investments in renewable electricity generated outside of California (JUG comment letter enclosed). (LADWP)

Response: Many commenters suggest that staff modify the accounting of zero-emission power under MRR by assigning zero emissions to the REC as opposed to the directly delivered electricity into the State as a means of better aligning the Cap-and-Trade and RPS Programs. Along the same lines, some commenters argued against removing the section 95852(b)(3)(D) requirement to report RECs for specified sources. Some commenters argue that implementation of the RPS Adjustment and specific source reporting requirements have limited the usefulness of the RPS Adjustment and result in unexpected costs to ratepayers, and request additional allocation for “firmed and shaped power.” See response to 45-day comment D-3.2. Further, staff notes that MRR still retains the requirement to report REC serial numbers for specified sources; staff never proposed to change this provision of MRR.

Some commenters argue that the section 95852(b)(4)(D) requirement that the electricity associated with RECs used for an RPS Adjustment cannot have been directly delivered, should be changed to specify that said electricity cannot be brought into the State as a specified import. Staff notes that this proposal is outside the scope of the current regulatory changes. Further, staff does not believe that this proposal would change an importer’s ability to claim an RPS adjustment in compliance with MRR and the Cap-and-Trade Regulation, and therefore changes to these provisions are not necessary.

D-3.2. Comment:

NCPA appreciates CARB’s responsiveness to stakeholder opposition to eliminating the RPS Adjustment from the cap-and-trade program and the modified amendments that would reinsert this provision. As CARB has acknowledged, the RPS program is a key element of California’s recommendations for reducing its greenhouse gas emission to 1990 levels by 2020.⁸⁵¹ Both the cap-and-trade program and the RPS program serve the same underlying purpose – to reduce the state’s overall GHG emissions profile; for that reason it is imperative that there be greater alignment between the two programs. In furtherance of this objective, and to avoid unnecessary compliance costs, NCPA encourages CARB to continue to work with stakeholders to address the articulated concerns regarding the manner in which the provision is implemented and the

⁸⁵¹ Climate Change Scoping Plan, December 2008, pp. 16-17, see also p. 44.

unintended impacts that have resulted. Amendments should also ensure that both the cap-and-trade program regulation and the Mandatory Reporting Regulation retain the requirement for entities to report the REC serial number. Doing otherwise needlessly dissociates the two programs where they should be more explicitly aligned. NCPA encourages CARB to carefully review the proposal set forth in the Utilities' January 20, 2016 letter, and incorporate the necessary amendments into subsequent 15-Day Changes. (NCPA)

Response: Thank you for the support. Staff notes that MRR still contains the REC serial number reporting requirement for specified sources; staff never proposed to change this provision of MRR.

D-3.3. Comment:

The Initial Statement of Reasons and Notice for this rulemaking noticed possible amendments to Section 95852(b)(4) (i.e., the "RPS Adjustment"). DEB supports the ARB's December 20, 2016 proposal to retain the RPS adjustment.

Since Section 95852(b)(4) is within the scope of this rulemaking, the ARB should take this opportunity to clarify Section 95852(b)(4)(A) to ensure that a power marketer's presence in the chain of contract for Procurement Content Category 2 ("PCC-2") energy does not nullify an importer's ability to claim the RPS adjustment. Currently, Section 95852(b)(4)(A) requires the electricity importer (i.e., the entity claiming the RPS adjustment) to either have: (1) ownership or contract rights to the RECs and energy from the RPS facility; or (2) a contract with an entity that is subject to the RPS and that has ownership or contract rights to the Renewable Energy Credits ("RECs"). Section 95852(b)(4)(A) does not explicitly contemplate an arrangement where a power marketer contracts with an electricity importer to receive and reconvey PCC-2 firmed and shaped energy to an entity subject to the California RPS. If the second qualification (i.e., having a contract with an entity subject to the RPS) is read strictly, it would require the electricity importer to have privity of contract with the RPS obligated entity.

Such a requirement would be arbitrary because there is no reason that the presence of a power marketer in the chain of contract in any way reduces or minimizes the greenhouse gas attributes of the firmed and shaped power. In fact, if the regulations were read in this way, that interpretation would be counterproductive to the broader goals of AB 32 because RPS obligated entities that typically contract through power marketers (e.g., Community Choice Aggregators) would have fewer options to procure RPS eligible energy. The PCC-2 contract structure is critical to the developing CCA market because the CCAs often wish to procure RPS eligible energy on a short-term basis. PCC-2 energy is currently one of the most inexpensive options for RPS eligible energy.

The ARB should remove this potential barrier to the efficient operation of the wholesale power markets by amending Sections 95852(b)(4)(A) and (B) as follows:

(A) The electricity importer must have:

1. Ownership 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 or contract rights to the electricity and associated RECs generated by the eligible renewable energy resource, as verified pursuant to the MRR, or
3. A contract with an intermediary electric power entity, and the intermediary electric power entity has a contract to provide an entity subject to the California RPS with the electricity and associated RECs generated by the eligible renewable energy resource that is owned or contracted by the electricity importer.

(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 specified in section 95111(g) of MRR for the year for which the RPS adjustment is claimed

As discussed above, since the ARB noticed possible amendments to Section 95852(b)(4), these proposed amendments would be within the scope of this rulemaking based on a plain reading of the California Administrative Procedures Act. DEB's proposed amendment is necessary to avoid an arbitrary denial of the RPS adjustment based on the presence of a power marketer in the chain of contract for PCC-2 energy. Our proposed amendment will also further the broader GHG emission reduction goals of AB 32 by achieving greater coordination with the RPS program and ensuring that RPS obligated entities such as CCAs have all options at their disposal for procuring RPS eligible energy at least cost to their ratepayers. (DIRECTENERGY)

Response: The commenter requests that the language in section 95852(b)(4)(A) of the Regulation be expanded to allow for additional entities to claim an RPS adjustment. Contrary to the commenter's assertion, staff did not propose changes to the specific paragraph in question as part of this rulemaking. As such, this comment is outside the scope of proposed changes to the regulation.

D-4. Voluntary Renewable Energy (VRE)

D-4.1. Comment:

ARB staff proposes to stop setting-aside allowances for the Voluntary Renewable Electricity (VRE) program in the post-2020 compliance periods. SMUD believes that ARB is acting prematurely on this issue, and supports a continued VREP set aside allocation post-2020.

SMUD relies on the VRE program to ensure promised carbon reductions to our popular Greenergy voluntary renewable program. SMUD suggested in one of the preliminary

workshops last fall that ARB should be prepared to expand and extend the VRE program, given the potential for new voluntary green pricing participation pursuant to SB 43 and more recently SB 350. It was just this year that the IOUs received permission from the CPUC to establish their voluntary green pricing programs pursuant to SB 43. Depending on the uptake of voluntary solar procurement under these new programs, similar programs now facilitated by SB 350 at POUs, and the ARB staff proposed changes allowing easier participation by distributed solar participants, the VREP allocation as it stands could be fully used by 2020. In SMUD's case, our Greenergy program is seeing a period of rapid expansion, with participation increasing by more than 50% in the last several years.

ARB's contention that the VRE program is undersubscribed is based on only two years of program operation that occurred before the new programs and recent growth. ARB should await more information about how this expected growth impacts VRE program participation before determining that no further set aside is required. Otherwise, ARB runs the risk of stopping the growth of, and even causing declines in, these clean energy options as consumers realize their voluntary efforts are not providing GHG reductions as expected.

SMUD would support funding the VREP post-2020 at the same level as in 2020 using allowances that have remained unsold in the Cap-and-Trade auction for a period of two or three years. (SMUD)

Response: This comment is outside the scope of the first 15-day changes to the Regulation. See also response to 45-day comment D-4.6.

E. OFFSETS AND OFFSET PROGRAM IMPLEMENTATION

E-1. Availability and Usage of Offsets

Offset Supply

E-1.1. Multiple Comments:

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, and represent a real, quantifiable, enforceable, verifiable, additional, and permanent GHG reduction.

Offsets help keep GHG compliance costs affordable to customers as there may be compliance cost savings from purchasing offsets. This important cost-containment function will become even more important as the Cap-and-Trade Program becomes more stringent through 2030. Any consideration of reducing the offset limit must include a thorough analysis of the effects on the cap-and-trade market, compliance costs, and emissions. As part any such review, PG&E encourages ARB to present the results of scenarios with offset usage limits higher than eight percent as well as lower usage

limits. A higher offset usage limit may be appropriate post-2020 as a cost-containment tool amidst an increasingly stringent program. (PG&E)

Comment:

The Need For A Broad Use Of Offsets:

Offsets are a proven and cost---effective means of meeting AB 32 compliance obligations. CCPC supports our members and like-minded groups with the notion that a robust offset program is a key cost containment mechanism. A robust supply of offsets is required in order to reduce program costs. Expanding the allowable use of offsets is a sound policy choice. Numerous economic studies have shown, including ARB's own analysis, that offsets are the best market-based alternative to reduce costs and limit leakage. Expanded use of offsets is consistent with ARB's statutory obligation to achieve the maximum technologically feasible and cost-effective GHG emissions reductions. (CCPC)

Comment:

OFFSETS ARE ESSENTIAL

CalChamber maintains its position that a robust offset program is a key cost containment mechanism. A robust supply of offsets are required in order to reduce program costs. Therefore, a consideration of offset protocols is encouraged. Expanding the allowable use of offsets is a sound policy choice. Numerous economic studies have shown, including CARB's own analysis, that offsets are the best market-based alternative to reduce costs and limit leakage. Expanded use of offsets is consistent with CARB's statutory obligation to achieve the maximum technologically feasible and cost effective GHG emissions reductions. Offsets are a proven and cost-effective means of meeting AB 32 compliance obligations. (CALCHAMBERCOMMERCE)

Comment:

TID understands that, even though the Quantitative Usage Limit on Offsets language was retained in the 15 day language, that GHG offsets and their usage for compliance are very much a topic for discussion for future rulemakings. TID supports the retention of the Quantitative Usage Limits as currently constructed, as GHG Offset projects incentivize real emissions reductions, even though they may be outside of the California State boundaries. The Cap & Trade Program is now regional, and any change, cut, or redefining of GHG Offset eligibility would only serve to drive up compliance costs. (TURLOCKID)

Response: Commenters are requesting an increase in the quantitative usage limit for offset credits, which is currently set at eight percent by section 95854(b). One commenter also supports the addition of new Compliance Offset Protocols. ARB staff responded to similar comments in their responses to 45-day comments E-1.1.

Quantitative Usage Limit

E-1.2. Comment:

We agree with the staff's conclusion in the Amendment Package that no changes to the offset usage limit is warranted.

There is a myriad of reasons why offsets were included in the original design of the AB 32 program, and why they should be retained in the program, including:

- Additional GHG reductions that would not otherwise be realized
- Direct reductions in Short-Lived Climate Pollutants (SLCP)
- Incentives to improve water quality, habitat and working lands
- Creates jobs and economic activity in disadvantaged communities
- Creates jobs and economic activity in rural and tribal communities
- Reduction in overall program costs
- Mobilizes investments in clean technologies developed by California companies
- Mobilizes investments and innovations in sectors outside those covered under the GHG permitting program or direct command and control regulations
- Facilitates linkages with other jurisdiction's climate programs

ARB should be congratulated for meeting its Program goals with a 100% compliance rate, while also achieving the multiple co-benefits sought by AB 32, including clean technology advancements and reductions in other air pollutants, thanks to a constellation of the most rigorous pollution controls in the world. In addition to the Cap and Trade program success, California is meeting its aggressive goals on renewable energy, fuel economy, and Low Carbon Fuels, and is on pace to meet its overall GHG targets by 2020. Equally impressive is the 28% economy-wide reduction in carbon intensity since 2001 over which time the state's GDP grew by the same amount (28%).

There has been considerable comment and we believe in some cases, misunderstanding, on whether and how offsets impact disadvantaged communities. We believe however that the current offset program has already achieved tangible benefits to Californians and disadvantaged communities, for example:

- To date, 54 offset projects have been conducted in California (ARB lists only 24 but these do not include a number of projects involving recovery of CFC refrigerants from end-of-life equipment in California, with destruction outside the state.
- Approximately 30% of the total 54,552,984 offsets issued by the ARB, have been created within California's borders.

- These total reductions come from 46 projects that are providing economic benefit in 20 separate California disadvantaged communities and 26 disadvantaged communities outside of the state.

Summary

California's program advanced the policy idea that the broader non-regulated community could participate in helping the State achieve its ambitious GHG goals through the inclusion of offsets. This policy framework has been, and continues to be, successfully exported throughout North America. Any change in policy direction at this stage of implementation would be a significant setback to those who have committed to the program, including non-profit environmental groups, clean technology businesses, other jurisdictions potentially linking to California, and the millions of Californian voters, ratepayers, and taxpayers who are benefitting from not only cleaner air but a more vibrant, advanced economy. It also would send the wrong message to a world that is watching California's every move. The Offset Group stands ready and available to discuss these issues with staff, EJAC members, the Legislature or ARB Board members as needed. (ADHOCOFFSETS)

Response: Thank you for the support.

Opposition to Offsets

E-1.3. Comment:

Eliminate offsets. Actions and investments taken by industry to reduce emissions need to be reinvested in the communities where the emissions have occurred. Any benefits from greenhouse gas reduction measures must affect California first. In addition to California emissions, also consider activities that can reduce pollution coming from across the Mexican border, to reduce emissions in the border region. (EJAC)

Response: The commenter proposes eliminating offsets. Since ARB staff has not proposed changes to the ability to utilize offset credits up to the eight percent quantitative usage limit as part of this rulemaking, comments related to elimination of offsets are outside the scope of the rulemaking; therefore, no further response is required.

E-2. General Offsets

Forest Buffer Account

E-2.1. Comment:

§95985(h)(3) and §95985(i)(3) – Replacing Invalidated Buffer Pool Credits

We appreciate ARB's consideration of our suggestion to base the number of ARB offset credits that the Offset Project Operator must replace in the Forest Buffer Account to the percentage of ARB offset credits in the Forest Buffer Account that have been retired for unintentional reversals. In our original comments dated September 19, 2016, we noted

that this comment was relevant to §95985(h)(3). However, for consistency, we believe this change should also be implemented in §95985(i)(3) of the Regulation. The Reserve would like to thank the Members of the Board as well as the ARB staff for their consideration of these comments and for their continued efforts to improve the Compliance Offset Program. (CLIMATRESERV)

Response: This comment refers to the proposed changes to sections 95985(h)(3) and 95985(i)(3). In the 45-day amendments, ARB staff proposed to require the offset project operator or forest owner replace 50 percent of invalidated offset credits from the Forest Buffer Account. Based on stakeholder comments to the 45-day amendments, ARB amended section 95985(h)(3) in the first 15-day amendments to require the percentage of offset credits replaced to equal the percentage of offset credits retired from the Forest Buffer Account as of the date of invalidation. ARB staff agreed with the commenter that a similar change should have been applied to section 95985(i) for consistency, and made this change in the second 15-day amendments.

E-2.2. Comment:

Bluesource supports the change from an arbitrary 50% to a proportional and accurate amount of buffer account credits required to be replaced in the case of an invalidation. This approach ensures the integrity of the buffer pool, the primary goal. (BLUESOURCE)

Response: ARB appreciates the commenter's support.

E-2.3. Comment:

Specific to proposed forest reversal invalidation amendments, we recognize that Section 95985⁸⁵² revisions attempt to address perceived risk that credit invalidation could lead to buffer pool credit elimination that had already been retired to compensate for unintentional reversals from other projects. However, a more effective approach to addressing this issue – rather than implement an arbitrary 50% buffer replacement requirement – should be considered by ARB.

In the case of forestry invalidation, IETA recommends that the number of buffer account credits required to be replaced be calculated on a project-by-project basis and based on the total percentage of buffer pool credits that have been retired to compensate for reversals up to the date of invalidation. Ultimately, this approach would ensure integrity

⁸⁵² Under Section 95985(h)(3) – “The Offset Project Operator, identified in section 95985(e)(3), of an offset project that had ARB offset credits removed from the Forest Buffer Account pursuant to section 95985(g)(1)(A)3. or (g)(1)(B) must replace 50% of ARB offset credits removed from the Forest Buffer Account, rounding up to the next whole number, with a valid ARB offset credit or another approved compliance instrument pursuant to sub-article 4, within six months of notification by ARB pursuant to section 95985(g)(2).”

of the buffer pool and allow for a defensible, justifiable amount compared to a blank 50% amount. (IETA)

Response: This comment focuses on new subsections 95985(h)(3) and (i)(3) proposed in the 45-day amendments, which would have required forest offset project operators and current forest owners to replace 50 percent of the offset credits removed from the Forest Buffer Account in the event of an invalidation. Commenter recommends that the number of invalidated offsets required to be replaced should instead equal the percent of Forest Buffer Account offset credits that have been retired as of the date of invalidation.

In response to multiple similar comments received during the 45-day comment period, ARB staff made the specific change this comment recommends to section 95985(h)(3) in the first 15-day amendments. Another commenter noted during the first 15-day comment period that the change should also have been applied to section 95985(i)(3) for consistency. ARB staff agreed and modified the proposed language in section 95985(i)(3) in the second 15-day amendments.

Miscellaneous

E-2.4. Comment:

IETA has previously encouraged ARB to improve its invalidation approach. This includes our consistent recommendation to eliminate California's current buyer-liability approach altogether in favor of adopting a model similar to Québec's Environmental Integrity Account (EIA) mechanism. With IETA's support, Ontario has also opted to the EIA approach in its recently-proposed offset regulation. California would significantly benefit from taking a similar approach to their partner jurisdictions.

By eliminating the current buyer-liability approach in favor of an EIA-type mechanism, California would lower the costs of offset creation by reducing the cost of verification, streamlining the process for ARB staff and mitigating the need for compliance entity risk management. A lower cost of offset creation, while maintaining the same level of program rigor and integrity, equates to cost mitigation for compliance entities and more broadly to California ratepayers and residents. In addition, we continue to urge ARB to provide heightened clarity on invalidation investigation timing, process, and overall communications to all regional market participants – not just those impacted by a given investigation.⁸⁵³ (IETA)

Response: The commenter believes that ARB should remove the requirement for owners of offset credits to replace invalidated offset credits, referred to as "buyer liability," and instead, should establish an "environmental integrity"

⁸⁵³ See IETA Comments on California Air Resource Board's Workshop on Potential 2016 Amendments to Cap-and-Trade Regulation, submitted to ARB on 11 March 2015.

account similar to Québec to address invalidation risk. See ARB staff's response to 45-day comment E-4.2.

E-2.5. Comment:

Benefits of Cap and Trade and Offsets

California's climate policies have done great things for the State and also for the rest of the country and world at a time when sub-national climate leadership may be more important than ever. As an example, a recent study of the economic impacts of California's climate programs on the San Joaquin Valley completed by UC Berkeley found that Cap and Trade has had the positive impacts of 1,612 jobs and \$202 million in total economic activity. Additionally, the study found that total employment, personal income and household incomes also rose over the first three years of Cap and Trade implementation.

Looking at accomplishments within the offsets program in particular:

- More than 16,000,000 tons of CO₂-equivalent, or approximately 30% of all offsets issued to date have been reduced inside California from sectors beyond the cap.
- 54 offset projects are reducing emissions in California.
- 46 projects are serving disadvantaged communities, 20 of which are serving disadvantaged communities within the State.

Despite these clear benefits of Cap and Trade and of offsets, there are some that oppose both systems and make claims that harm is actually being done to local communities. We in no way want to minimize the very real challenges that disadvantaged communities face with respect to local air pollution, but we think it's important to base policy decisions on facts rather than conjecture or preliminary analysis. One of the reports that has frequently been cited by opponents to Cap and Trade and offsets is a preliminary study that specifically states that, "Further research is needed before firm policy conclusions can be drawn from this preliminary analysis." Those that are using this report to try to influence policy decisions are therefore going directly against the advisement of the report's own authors. Furthermore, this study goes on to say that, "As regulated industries adapt to future reductions in the emissions cap, California is likely to see more reductions in localized GHG and co-pollutant emissions," the very achievement opponents of Cap and Trade seem to want.

Bluesource supports the continuation of Cap and Trade and offsets and cautions against sweeping claims that offsets harm communities, when the facts clearly show a plethora of community benefits, including:

- Improved air quality
- Improved water quality

- Reduction of odors
- Renewable energy creation
- Job creation
- Fire risk reduction
- Habitat preservation
- Responsible waste disposal

(BLUESOURCE)

Response: ARB appreciates the commenter's support.

E-2.6. Comment:

SMUD also supports consideration of adding the following cost-containment measures:...

- Finding a way to apply the 8% offset limit to facilitate full use of offsets up to the limit. It is now clear from the record in the first compliance period that the market did not fully utilize offsets – only 4.5% of the compliance instruments surrendered were offsets, well below the 8% limit. As SMUD and other stakeholders have noted, greater use of offsets will help to contain the costs of obligated entities under the Cap and Trade program. SMUD suggests that the ARB either: 1) allow entity's to "carry over" any unused portion of the offset limit across compliance periods; 2) spread unused amounts over the broader market so that the limit is fully used; or 3) establish an "offset-limit bank" in which unused portions of the 8% limit could be offered up as the APCR is accessed – essentially extending the concept of holding back some compliance instruments to be released when/if prices get to the APCR level.
- Exempt from the offset limit any offsets that provide in-state ancillary environmental benefits similar to actual reductions at capped sector facilities, by offering more of the following benefits: 1) a direct reduction or avoidance of any criteria air pollutant in California; 2) a direct reduction or avoidance any impacts on water quality in California; 3) a direct alleviation of a local nuisance within California associated with the emission of odors; 4) direct environmental improvements to land uses and practices in California's agricultural sector; 5) direct environmental improvements to California's natural forest resources and other natural resources; and/or 6) a direct reduction of the need for mitigation of the impacts within California of rising global greenhouse gas emissions.
- Streamlining of offset policy while maintaining offset integrity that allows compliance entities (particularly smaller entities) to access offsets up to their current limit. For example, the buyer liability aspect of most offsets imposes a

market risk that prevents many from considering the offset alternative, even with market-insured “golden” offsets. SMUD encourages ARB once again to move away from buyer liability in current and future offset protocols.

- Including Sector Based offsets. SMUD appreciates the efforts that ARB staff has undertaken to start including Sector Based Offsets in the Cap and Trade program, and the stated intention of continuing to pursue such inclusion, even while not being able to include in this rulemaking.

(SMUD)

Response: The commenter proposes several options to allow unused portions of the quantitative usage limit to be used in the future, suggests ARB move away from “buyer liability,” in reference to the responsible party for replacing invalidated offset credits, and expresses support for ARB’s effort to-date regarding potential inclusion of sector based offsets.

ARB staff did not propose any changes to provisions related to the quantitative offset usage limit or exemption of any offsets from the limit; therefore, these comments are outside the scope of the rulemaking and do not require a response. ARB staff also did not propose any 15-day changes to the language in section 95985(e) identifying affected parties related to invalidation, therefore the comment regarding buyer liability is also outside the scope of the rulemaking and does not require a response. However, “buyer liability” requires that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. Therefore, ARB staff did not make any changes in response to these comments.

ARB staff appreciate the commenter’s support of ARB’s efforts regarding the potential inclusion of sector based offsets in the future.

E-3. Compliance Offset Protocols

E-3.1. Comment:

§95973(a)(2)(D) – Transitioning to a New Version of a Compliance Offset Protocol

This section currently limits an Offset Project Operator’s or Authorized Project Designee’s (OPO/APD) ability to transition a project to the latest version of a Compliance Offset Protocol. We believe this requirement unnecessarily requires an OPO/APD to continue to use an old version of the relevant Compliance Offset Protocol, even if they would voluntarily choose to transition to a new version for a given reporting period. Newer versions of the Compliance Offset Protocols represent the latest policy developments and often contain corrections, improvements, and enhanced usability for both the OPO/APD and the verification body. ARB should allow projects that can meet

the timing requirements of the Regulation and the latest version of a protocol to use it, regardless of what version the initial Offset Project Data Report (OPDR) was submitted under. (CLIMATRESERV)

Response: This comment focuses on the existing limitation in section 95973(a)(2)(D) that an offset project operator may only transition a project to the most recent Compliance Offset Protocol version at the initial submittal of the Offset Project Data Report. ARB staff did not propose any changes to this requirement as part of this rulemaking; therefore, this comment is outside the scope of the rulemaking and does not require further response.

E-3.2. Comment:

CCEEB is concerned with the restriction of offsets generated in Canada and Mexico. While we understand staff's assertion that these offset projects can now be handled through linkage, there is no compelling reason to limit an already limited market. Furthermore, CCEEB is concerned with the "guilty until proven innocent" approach these amendments take towards offset invalidations. These changes on offsets limit supply, add risk, and constrict a critical cost-containment mechanism for the program. Offsets extend the influence of Cap-and-Trade to sectors and jurisdictions not covered by California's climate policy. If the ultimate goal is to mitigate and reduce greenhouse gases, this policy change will reduce California's impact in achieving global emission reductions, yet increases costs to Californians. (CCEEB)

Response: This comment refers to the 45-day changes to sections 95972(c) and 95973(a)(3) which specify where offset projects eligible to receive ARB offset credits must be located. The proposed 45-day language eliminated Canada and Mexico from possible locations for ARB offset projects. As indicated in the ISOR, practically, this change has no effect since all ARB protocols are currently limited geographically to the United States. ARB would continue to issue offsets to eligible projects in the United States, whereas eligible projects in Canada may be issued offsets by Québec or Ontario, subject to approved protocols. As further indicated in the ISOR, offsets in other countries, such as Mexico, would have to be issued by those jurisdictional programs authorized via linkage. No further changes were proposed to this language in the 15-day amendments; therefore, this comment does not require further response.

E-4. Regulatory Compliance

E-4.1. Multiple Comments:

§95973(b)(1) and (b)(2) – Eligibility and Regulatory Compliance

We applaud ARB's proposal to limit the period of ineligibility for a project to the period the project was out of regulatory compliance; this is how the Reserve's own voluntary program has handled regulatory noncompliance issues since its inception and believes it is an equitable approach to ensure the penalty matches the magnitude of the violation.

However, this change should apply to all project types listed in 95973(a)(2)(C), including forest, urban forest and rice cultivation projects. In our voluntary program, we have had many instances of forest projects with regulatory compliance infractions, and the project developers have been able to supply the same level of documentation for defining the duration of a noncompliance event as any other non-land-based project type. Regulatory compliance requirements should be enforced and penalized equitably across all project types. (CLIMATRESERV)

Comment:

Bluesource supports ARB's proposed change to limit the period for which a livestock, MMC or ODS project would be ineligible to receive offset credits for being out of regulatory compliance to the precise time period during which the project was actually out of compliance, as opposed to the entire Reporting Period. This will motivate projects to return to compliance as quickly as possible. The proposed change has been reflected in section 95973(b)(1); however, 95973(b)(2) excludes forestry, urban forestry and rice cultivation projects from this important regulatory update. Excluding these project types is inconsistent with the other regulatory changes that have prioritized parity between offset types, so as not to unfairly advantage one over another.

While a prior Statement of Reasons document stated that "Other project types cannot be included in this proposal because there is no quantification mechanism within the applicable protocols to identify and remove crediting of partial Reporting Periods," we adamantly disagree with this conclusion since credits associated with a particular period of non-compliance could be readily and accurately calculated from forestry projects. By way of example, if a forestry project was found to be out of regulatory compliance, the carbon sequestration represented in the forest growth and the wood products generated (if any) during the period of non-compliance could be subtracted from the reporting period. This can be accomplished to a high degree of accuracy by accounting for the precise growth and harvesting activities that took place during the period of non-compliance. Given this ability to quantify and remove crediting of partial Reporting Periods for forest projects, and ARB's general policy that all offset project types should be given the same regulatory treatment wherever possible, we believe forestry projects should be included with livestock, MMC and ODS in the amendment to the regulatory compliance rule.

It should also be noted that any claims of start and end dates or calculations of affected Offset Credits during a period of noncompliance would need to be "to the satisfaction of ARB," similar to this same requirement in Section 95973(b)(1). (BLUESOURCE)

Comment:

The proposed modifications to constrict the invalidation of offsets to the period of the non-compliance is a sensible change that ensures the penalty is not inordinate to the violation. However, The Climate Trust is concerned that this is not supplied uniformly across all project types. Under Section 9598 (c)(B), forestry projects stand lose an

entire reporting period's volume of offsets if a project is out of compliance. Forestry projects are no different from other projects and the period of non-compliance could be a matter of days. As such, its excess to invalidate the entire volume for such a small duration of non-compliance. The Climate Trust advises ARB to adopt a consistent standard that invalidates offsets that are commensurate with the duration of non-compliance. (CLIMATE TRUST)

Comment:

We also have concerns about fair treatment of invalidation timeframe limits across all offset project types. IETA welcomes ARB's proposal to place clear limitations on the invalidation timeframe for regulatory compliance issues for livestock, ODS and mine methane capture projects. As previously communicated to Staff, these modifications will give developers greater incentive to bring projects back into compliance as quickly as possible, while limiting the penalty for regulatory non-conformance to the period of time during which the project was out of conformance. However, we strongly encourage ARB to extend modified language related to invalidation timeframe limits to all compliance offset project types. ARB should maintain the flexibility to allow forestry and Rice Cultivation offset projects the opportunity to demonstrate that a regulatory non-compliance period – one associated with a particular time period during a reporting period – does not impact the entire reporting period's achievements. Where possible, all offset project types should be given the same regulatory treatment, consistent with previous regulatory changes. (IETA)

Response: These comments focus on the proposed language in section 95973(b)(1) and subsections allowing for certain offset project types to be considered out of regulatory compliance for only part of a reporting period, so that the project may still receive offset credits for the part of the reporting period for which the project was in regulatory compliance. The commenters assert that all project types should be allowed to similarly constrain the timeframe of regulatory noncompliance.

The 45-day amendments proposed language to allow this approach for livestock and mine methane projects only. During the 45-day comment period, multiple commenters requested that ARB extend this approach to all project types. In response to the 45-day comments, ARB staff changed the language in the first 15-day amendments to extend the approach to Ozone Depleting Substances (ODS) projects, as discussed in the response to 45-day comments E-8.4.

The above comments, similar to the 45-day comments, request that ARB extend this approach to the remaining offset project types. ARB staff declined to extend the approach to the remaining project types for the reasons discussed in the response to 45-day comments E-8.4.

E-4.2. Comment:

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. (PG&E)

Response: The commenter states that there is “asymmetry” between the start and end date of when a project would be considered out of regulatory compliance, and that there should be an “opportunity to cure in the event of a gap in reporting” in offset projects.

The first comment regarding “asymmetry” is addressed in the response to 45-day comment E-8.10. The commenter’s assertion that there should be an “opportunity to cure in the event of a gap in reporting” is addressed in the response to 45-day comment E-6.8.

E-4.3. Multiple Comments:

The insertion of language in Section 95973 (b) allowing ARB discretion to determine whether a regulatory violation has occurred is worrisome. Such broad discretion has the potential to generate confusion and uncertainty as to what the grounds for an invalidation may be. This could chill participation in the offset market, as there is no clear guidance on ensuring a project might not be subject to an invalidation. The Climate Trust strongly recommends ARB strike the following proposed insertion: “...whether enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance...” (CLIMATETRUST)

Comment:

We applaud clarity on offset regulatory compliance language. However, proposed language related to ARB discretion on determining regulatory compliance - along with limiting “out of compliance” time periods to discrete offset project types - remains problematic...

IETA is deeply concerned about the inclusion of ARB discretion in determining whether a project is out of regulatory compliance. While most proposed language in Section 95973(b) adds clarity about whether an offset project will (or will not) be eligible to receive credits, the following statement is extremely problematic and has the potential to undermine added clarity: “...whether enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory

compliance...” One serious potential effect of lack of clarity and uncertainty may be to chill the development of robust offset projects. IETA strongly urges ARB to remove this language in the final amended regulation.

As proposed, the above language will spawn uncertainty and risks for offset project operators (OPOs) as well as verifiers. The current regulatory compliance standard references regulatory oversight bodies, which make it clear for OPOs and verifiers who they should look to in order to confirm regulatory compliance. If the amended Regulation allows ARB the discretion to make its own determination of regulatory compliance (above and beyond the applicable regulatory oversight body), this creates an unclear and inconsistent regulatory compliance standard. For instance, if ARB decides that a project has violated its permit, even if the oversight body has not issued a violation, it is impossible for the verification body to verify the project to the requirements of 95973(b) without sending all project EH&S information to ARB for review. It is unclear how a verification body would be able to verify that a project has met the requirements of 95973(b) without first having ARB confirm that a project is in regulatory compliance.

Once again, IETA urges the removal of this language from the final amendment package. (IETA)

Response: These comments refer to proposed 45-day language in section 95973(b). No further changes were made to section 95973(b) in the 15-day amendments. Therefore, these comments are outside the scope of the 15-day amendments and do not require a response. However, ARB staff responded to similar comments received during the 45-day comment period, in particular in response to 45-day comment E-8.2.

E-4.4. Comment:

Proposed changes to the provisions governing when an offset project will be deemed out of compliance with applicable regulatory compliance should not be adopted

ARB has proposed making several changes to the Cap-and-Trade Regulation’s provisions concerning the relevance of initiation of an enforcement action to ARB’s determination of whether an offset project was out of compliance with all applicable regulatory requirements and documentation of when such noncompliance began and ends. These proposed changes, which would provide the basis for determinations of when an offset project is ineligible for issuance of offset credits or previously issued credits could be subject to invalidation, are overly prescriptive and should be rejected.

The current Cap-and-Trade Regulation requires that offset projects must fulfill all applicable local, regional, and national environmental and health and safety laws and further provides that, “[t]he project is out of regulatory compliance if the project activities were subject to enforcement action by a regulatory oversight body during the Reporting Period.” Cal. Code Reg. tit. 17, § 95973(b). The proposed amendments would add the caveat that, “whether such enforcement action has occurred is not the only

consideration ARB may use in determining whether a project is out of regulatory compliance.” Proposed Amendments § 95973(b). In other words, ARB may consider other information establishing whether an offset project is out of compliance in determining whether a project should be deemed ineligible for issuance of offset credits and/or whether previously issued credits should be invalidated.

The proposed amendments would also set forth specific criteria for determining the time period of noncompliance for offset projects implemented under the ozone depleting substances (“ODS”), livestock and mine methane protocols, as follows:

The time period that the offset project is out of regulatory compliance begins on the date that the activity which led to the offset project being out of regulatory compliance actually began and not necessarily the date that the regulatory oversight body first became aware of the issue.

Proposed Amendments, Aug. 2, 2016, at § 95973(b)(1)(A).

The proposed amendments then provide that, “[f]or determining the initial date of the offset project being out of regulatory compliance the Offsets Project Operator or Authorized Project Designee must provide [inter alia] ... [d]ocumentation from the relevant local, state, or federal regulatory oversight body that initiated the enforcement action identifying the precise start date of the offset project being out of regulatory compliance.” See id. at § 95973(b)(1)(A)1. In the absence of such documentation, then, under the August proposed amendments, ARB will presume that the offset project was out of compliance starting on the day after the last inspection conducted by the relevant regulatory agency which initiated the enforcement action that did not indicate that the project was out of compliance (i.e., the last compliant inspection). See id. at § 95973(b)(1)(A)2.-3.

In the proposed 15-day changes, ARB proposes to remove all references to initiation of an enforcement action from these provisions. See 15-day changes at § 95973(b)(1)(A)1., 2. and 3. Similarly, for purposes of determining the date “when the offset project returned to regulatory compliance,” ARB has deleted references to initiation of an enforcement action, but is nevertheless requiring documentation from the relevant regulatory agency “stating that the offset project is back in regulatory compliance...”. See id. at § 95973(b)(1)(B).

Calpine does not disagree that whether or not an enforcement action has been initiated is not wholly determinative of whether an offset project was out of compliance with applicable regulatory requirements. However, the provisions ARB has proposed to add to the regulation prescribing how it will determine the start and end dates of noncompliance for ODS, livestock and mine methane projects reflect unrealistic assumptions about the type of documentation agencies regularly provide concerning regulated entities’ compliance status.

Even in cases where an enforcement action was initiated or where a settlement agreement confirms that a specific violation has been remedied, it would be highly unusual for a regulatory agency to provide documentation “stating that the offset project is back in regulatory compliance”, as required by proposed Section 95973(b)(1)(B). To further suggest, as do the proposed 15-day changes, that such a “clean bill of health” would be provided in circumstances where no agency enforcement action was initiated is even less realistic. Stated simply, regulatory agencies, due to limitations on their resources, are not generally in the business of providing written statements affirming a regulated entities’ compliance with applicable requirements.

The assumption that such statements will be provided appears to have been informed by the specific facts and circumstances of the one high-profile invalidation action taken to-date concerning ODS projects conducted at Clean Harbors’ El Dorado, Arkansas destruction facility. But the facts and circumstances of that case were unique and involved U.S. EPA’s preparation of detailed inspection reports with findings of noncompliance of the sort that are only rarely provided when an agency issues a notice of violation. Moreover, it is unlikely that a similar set of facts and circumstances will present itself in future ineligibility or invalidation determinations involving ODS, livestock or mine methane projects, particularly where no agency enforcement action has been commenced. And the set of rules ARB proposes for determining when the project was out of compliance risks ineligibility or invalidation for a much lengthier period than may be necessary to assure the Regulation’s requirements have been met.

Assume that ARB should receive information indicating that an ODS destruction facility was out of compliance with the requirements of its air permit for some period of time, but there was no involvement of the relevant regulatory agency in initiating an enforcement action or even in inspecting the facility during the past year. Under the proposed amendments and 15-day changes, the offset project could be deemed out of compliance all the way back until when the last inspection occurred and even beyond when the violation was completely remedied in the event that the facility or project operator cannot provide a written statement from the relevant regulatory agency of the sort contemplated by proposed Section 95973(b)(1)(B). This would potentially result in invalidation of offsets from destruction events occurring over a much lengthier period of time than necessary, even during periods when there was no evidence whatsoever of noncompliance. Such an outcome is not necessary to assure that the regulatory compliance requirement has been met and could only lead to the same type of market uncertainty that occurred in the wake of the initial of invalidation in the Clean Harbors case, an outcome that the proposed amendments are likely intended to avoid.

Calpine believes that the less prescriptive approach reflected by the current regulation for all offset projects and by Section 95937(b)(2) of the proposed amendments for projects implemented under the urban forests, U.S. forests and rice cultivation protocols would allow greater flexibility for ARB to consider the facts and circumstances of any particular case and decide on the appropriate period of time for ineligibility or

invalidation based on all the evidence available to ARB. While this very well might include written statements from the relevant regulatory agency and/or inspection reports of the sort that were obtained in the Clean Harbors case, it also could include a wide variety of other information of the sort suggested by Section 95973(b)(1)(A)1. of the proposed amendments.

Calpine does not disagree with the proposition reflected by ARB's guidance that, ultimately, under the current rules, it is up to the buyer of any offset credit to perform adequate due diligence to assure that the regulatory compliance requirement has been met and reduce the risk of invalidation, just as it is incumbent on ARB to assure that it has done a thorough job in evaluating each offset project's compliance with the Regulation. However, adopting a prescriptive set of rules for determining when the project first was out of compliance and then returned to compliance may only prevent ARB from considering all the relevant evidence and then deciding on an appropriate outcome in any particular case.

Accordingly, Calpine would urge ARB not to adopt the more prescriptive approach reflected by Section 95937(b)(1) for ODS, livestock and mine methane projects, but to maintain the flexibility provided by the current regulation and apply the same approach for determining the period of ineligibility or invalidation to all offset project types. If ARB thinks more detailed information may be helpful on the type of information that will be relevant to its determination, it should consider providing additional guidance of the sort it has previously issued on the subject. (CALPINE)

Response: This comment focuses on the proposed language in sections 95973(b), (b)(1) and its subsections.

The comment regarding section 95973(b) focuses on the proposed 45-day language clarifying that whether enforcement action has occurred is not the only consideration ARB may use in determining whether a project is out of regulatory compliance. No 15-day changes were made to section 95973(b), therefore the comment addressing this section does not require a response. However, ARB staff responded to several similar comments received during the 45-day comment period, in particular in response to 45-day comments E-8.2.

The commenter also asserts that the proposed amendments to section 95973(b)(1) are overly prescriptive. Commenter focuses on the proposed changes to sections 95973(b)(1)(A)1., 95973(b)(1)(A)2., and 95973(b)(1)(B). The commenter is concerned that regulatory agencies do not typically issue such documentation, and that the proposed language does not allow ARB enough flexibility in utilizing available information to constrain the time period of violation in the absence of such documentation from the regulating agency. The comments are mainly focused on the 45-day language and are outside the scope of the 15-day amendments.

ARB staff disagree that it would be problematic for offset project operators to obtain documentation to show that a violation or potential violation was resolved, even if there was no enforcement action. ARB staff have worked with regulatory agencies in many states to receive clarifications on regulatory compliance issues. In the majority of cases these regulatory agencies have been willing to provide additional documentation to ARB staff. Also, written documentation would include e-mail correspondence. ARB staff routinely accept email communications from regulatory oversight bodies as evidence of a project's regulatory compliance status in the course of reviewing offset project requests for issuance. In the absence of documentation from the regulatory agency, there are other options for determining the start and end date a project was not in regulatory conformance, such as inspection reports, which should be readily available to the project.

The commenter asserts that the language in Section 95973(b)(2), which applies to all project types under the current regulation, and would apply only to urban forest, U.S. forest and rice cultivation projects under the proposed amendments, would allow greater flexibility for determining the appropriate period of time for ineligibility or invalidation based on all the evidence available to ARB. No 15-day changes were proposed for section 95973(b)(2), so this comment does not require a response. Nevertheless, contrary to the commenter's assertion, this language is actually more restrictive to project operators and would prevent the issuance of ARB offset credits for the entire reporting period during which the project was out of regulatory conformance, regardless of the actual time.

ARB staff did not make any further changes to the 15-day language in sections 95973(b)(1), (b)(1)(A)1., (b)(1)(A)2., or (b)(1)(B) in response to this comment.

E-5. Verification

E-5.1. Comment:

Under Section 95976(d), ARB's proposal to mandate continuous reporting of offset projects is a reasonable requirement. IETA also supports the flexibility ARB has incorporated into verification requirements, including: allowing verifications to start 10 days after ARB receives documents; changes to verifier rotation; and providing developers greater choice in identifying suitable verifiers.

However, we remain concerned that a condensed timeframe of 15 days will not provide adequate time for modifications given the amount of work required. We therefore encourage ARB to include provisions that, upon request by ARB, give verifiers 30 days to revise verification statements and reports. (IETA)

Response: This comment expresses support to proposed changes to sections 95976(d) and certain verification requirements in 95977.1, and expresses concern regarding the proposed new section 95977.1(b)(3)(R)8. requiring a

verification body to resubmit a revised verification report and statement within 15 calendar days if ARB determines it doesn't meet the requirements of section 95977.1(b)(3)(R)4.

ARB appreciates the commenter's support of the proposed changes related to continuous reporting of offset projects and certain verification requirements.

The comment on section 95977.1(b)(3)(R)8. is in reference to 45-day language. No further changes were made to this section in the 15-day amendments; therefore, this comment does not require a response. However, ARB staff responded to similar comments received during the 45-day comment period; see response to 45-day comment E-7.3.

E-5.2. Comment:

Bluesource supports the proposed change to allow Sequestration Offset Projects demonstrating onsite carbon stock growth of 10% to extend the time between full verifications. This change will lower costs of program participation while still ensuring environmental integrity. (BLUESOURCE)

Response: ARB appreciates the commenter's support.

F. COMPLIANCE OBLIGATION SURRENDER

F-1. Changes to Compliance Obligations

Pre-2021 Vintage Allowances

F-1.1. Comment:

Pre-2021 Vintage Allowances to Satisfy 2021-2030 Compliance.

While the current regulation states that a compliance obligation can be met by any allowance from a current or previous vintage, the addition of post-2020 compliance periods, allowance budgets, and allocation structures may lead to a belief that the current program and the post-2020 program will not work seamlessly together. SMUD believes that it would be beneficial to explicitly state that pre-2021 allowance vintages can be used for compliance in years 2021-2030. This will remove any uncertainty in the market that any surplus allowances in the current program will have value in the post 2020 program. Removing any uncertainty that exists in this area could bolster current market performance (auction demand and clearing prices)....

SMUD also supports consideration of adding the following cost-containment measures:

- Include the ability for covered entities to use a limited amount of future vintage allowances for compliance in the current compliance period. Multi-year compliance periods provide compliance flexibility, but the end of a compliance period still represents a source of instability in the Cap-and-Trade structure. Currently, entities are limited to using only current vintage and past vintage

compliance instruments for any compliance deadline. For the 30% annual surrenders in the early years of compliance periods, this is not a significant market constraint. However, in the final year of a three-year compliance period, the entire period must be made whole with these vintages of compliance instruments, and, if demand here stretches supply, prices will inevitably reflect the market tightness. When the limited future-year allowances out in the market are not allowed to be used, they will likely be valued at substantially lower prices in the nearterm, reflecting the looser market conditions that will occur at the beginning of the next compliance period. There is a set of market conditions that may result in a three-year sine-wave in market prices, rather than a stable or a stably increasing long-term price trend. Such a pattern almost certainly will negatively affect investment decisions in emission reducing practices, exacerbating the tight market conditions over time.

- A broader concept of “overlapping” compliance periods, where the vintage 2018 allowances that have been allocated prior to the early November compliance period surrender “event” could be available for compliance, again at a premium. Note that not all of the 2018 vintage allowances would be available, as some are auctioned off in the fourth quarter auction every year, too late for the surrender event. The ARB can alter the Cap-and-Trade regulations to increase the allowances held for the final auction if desired. SMUD sees this overlapping concept as providing a market price smoothing effect between compliance periods, without really borrowing from future periods, since the allowances have been allocated or sold in the market prior to the surrender event.

(SMUD)

Response: ARB staff believes it is already clear that allowances issued through 2020 may be banked and used for compliance in 2021 and later. Section 95922 has not been modified in the current rulemaking, and the section makes clear that allowances do not expire and are not removed from the tracking system until they are submitted for retirement.

Staff disagrees with the comment that recommends more borrowing of future vintage allowances. The proposed amendments maintain the existing limited ability to borrow future vintage allowances when the Allowance Price Containment Reserve (Reserve) is depleted. This ability is extended through the 2021-2030 period. Staff believes the current level of permissible borrowing (1) is sufficient to provide adequate allowance supply to meet any likely demand scenario until the problem can be addressed, and (2) any further level of borrowing could potentially compromise the ability of the program to meet the statutory objectives.

Staff considered the use of overlapping compliance periods in its initial design work. While staff also saw some merits in the approach, the decision was made

after California's participation in the WCI design process to use the three-year compliance period approach. ARB is planning on retaining that approach. The proposed changes are contingent on the approval of California's Clean Power Plan (CPP) Compliance Plan. If that plan is approved, then California must conform its compliance periods with the CPP. If California's compliance plan is not approved, there will be no change to the compliance period schedule.

G. AUCTION AND TRADING REQUIREMENTS

G-1. Other Program Requirements

Holding Limits

G-1.1. Comment:

IETA strongly supports the increase in the purchase limit for voluntary participants to 25% at advance auctions beginning in 2018. The proposed approach will enable additional market liquidity and participation for future vintages. We applaud ARB for supporting this important modification. (IETA)

Response: While staff appreciates the support for the proposed change, please see our response to 45-Day comment G-1.4 for an explanation of why we are delaying that proposal for another rulemaking.

G-1.2. Comment:

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...

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 overallocation 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. (PG&E)

Response: The suggestion to increase the holding limit is beyond the scope of the proposed regulation as ARB staff did not propose such a change in the 45-day amendments. As such, no further response is needed.

Corporate Associations

G-1.3. Comment:

Section 95830(e)(1) and (4). Updating Registration Information

ARB proposes to add a new Section 95830(e)(1) to clarify the timing for updating registration information for registered entities. When there is a change in information registrants have submitted to ARB (e.g. change in directors and officers at an entity), registrants must update the registration information within 30 calendar days of the change. ARB in the ISOR states that it considers the "frequency of updates to be reasonable and necessary to ensure adequate market monitoring activities."⁸⁵⁴

Although LADWP has been complying with the 30 calendar day reporting requirement, LADWP proposes that ARB allow electronic submittal of the registration information changes and allow updating of registration information on a quarterly basis, instead of within 30 days, to reduce paperwork and streamline the process. There are occasions when the registration information with respect to changes to LADWP's directors and officers needs to be updated on an almost monthly basis. The current process requires the registrant to type the information into the form, have an authorized person sign the form, and then mail the original signed form to ARB. Similar to ARB's proposals in this rulemaking to accept electronic signatures, LADWP recommends electronic submittal to streamline the process. Quarterly updates to registration could be timed such that updated information would be available to ARB prior to the quarterly auctions to address market monitoring concerns.

Proposed Section 95830(e)(4) states that "an entity that fails to update registration information by the applicable deadline is subject to the restriction or revocation of its tracking system accounts pursuant to section 95921(g)(3), " which, as amended, clarifies that when a registered entity has its holding account revoked or suspended it "may not hold compliance instruments or register with the accounts administrator for another set of accounts in any capacity." All existing compliance instruments would have to be sold or retired. This leaves open the possibility that an entity's ability to comply with the program could be placed in jeopardy for a failure to update registration information, including for unintentional or minor violations of the updating requirements. For example, if LADWP updated the name of one of its officers in CITSS 31 days after the new officer had been appointed, its tracking system accounts could be restricted, in which case all compliance instruments would have to be retired and we would not be permitted to establish new accounts. This would completely prevent us from complying

⁸⁵⁴ 2016 1SOR at 111

with the Cap-and-Trade Regulation, or from operating in service of our customers as we are legally required to do.

LADWP requests that ARB revise this provision to provide more reasonable penalties and clearer standards that govern the exercise of discretion regarding what penalties apply to what violations. (LADWP)

Response: Please see response to 45-day comment G-2.6.

Miscellaneous

G-1.4. Comment:

Reporting Requirements. SCPPA agrees that ARB's addition of Section 95803 Submittal of Required Information will help streamline required data submissions via allowing for electronic submission. We concur that this change will facilitate timely interaction amongst reporting entities and ARB staff. It could also potentially reduce administrative costs and burden for both sides of the reporting process, which we fully support.

However, with respect to Section 95803(b), the default reporting response time of 10 calendar days is problematic. Given the uncertainty of what future requests may entail, and the nature of assuring quality data submissions, we recommend that ARB lengthen the default reporting timeline to at least 30 calendar days. Many reporting entities are increasingly resource-constrained; extending the default timeline will better support entities' ability to comply with the regulation while still ensuring that —good faith efforts are made in a prudent fashion.

Reporting can often be an iterative process, requiring communication between the reporting entities and ARB staff to clarify what is needed for compliance. To this end, we also recommend that ARB staff consider adding language into the regulation that acknowledges the need for flexibility in such instances. The language could, alternatively, be added into the Final Statement of Reasons to express staff's intent without a specific regulatory provision.

Furthermore, we recommend that ARB staff evaluate various reports/data points to determine whether further consolidation is feasible; any efforts to reduce the amount of reporting – or align timelines for report submissions, where possible -- would help minimize administrative burden and implementation costs for both ARB staff and reporting entities. (SCPPA)

Response: Please see response to 45-day comments G-2.6.

G-1.5. Comment:

CCEEB opposes the release of market sensitive information on holding and compliance accounts. The release of this information may make entities vulnerable to market manipulation and serves no purpose that cannot be met by compliance reporting

already available to ARB. Further, this information is proprietary and competitively sensitive. Release of this confidential information could provide entities with competitive advantages that would ultimately impact the market itself. This data includes:

- Quarterly CITSS Registrant Reports
- Quarterly Auction Summary Results Reports
- Annual Compliance Reports
- Annual summary of transfer reports
- Quarterly Compliance Instrument Reports
- Other data related to Cap-and-trade including GHG emissions reporting and California Climate Investment fund proceeds and investments

CCEEB is willing to discuss what additional aggregated data could be included, but rejects the 15-day changes, as we believe that they will substantially damage the market. (CCEEB)

Response: Staff disagrees with the comment. Staff are proposing to modify section 95921(e) in a way that clarifies that ARB will not release individually identifiable market sensitive or confidential business information. The reports cited in the comment do not constitute confidential business information because they aggregate individual account or transfer data to the point at which the identity of any one entity cannot be determined. The modifications remove any ambiguity from the requirement that ARB will protect the individual entity account information. See also response to 45-day comment K-1.5.

G-1.6. Comment:

Section 95803(b). Submission Deadlines

ARB has proposed a new Section 95803(b) that would add a default submission deadline for all information requested by the Executive Officer of 10 calendar days with the exception of specific provisions that state a specific date or period of time (e.g. September 1 of each year, 30 calendar days). Because the deadline is set in calendar days, it is possible that entities would have a maximum of 7 business days to gather and submit information, and as few as 5 days during holidays. This level of time is likely too short to comply with information requests of any complexity. LADWP recommends that ARB establish submission deadlines that are tied to the nature of the requested information. ARB could set a specific reasonable deadline for an information request at the time the request is made rather than a blanket one-size-fits-all requirement. Alternatively, ARB could establish a more reasonable default submission deadline such as 30 calendar days or the approximate equivalent in business days. (LADWP)

Response: Please see responses to 45-day comment G- 2.6.

H. GHG EMISSIONS BUDGET AND COST CONTAINMENT

H-1. GHG Emissions, Costs, and Other Priorities

H-1.1. Comment:

k. Increase the floor price to the real price of carbon; use the highest price offered, not the lowest. Incorporate industry's externalized costs into the cost of carbon (as is done with the mitigation grant program at Port of Long Beach). Calculate the cumulative impacts so they can be mitigated. Ensure that polluting facilities are paying the societal costs of their emissions, rather than externalizing them...

The price of carbon must be increased, with the resulting funds invested in local communities to ensure all benefits from a greenhouse gas free future. (EJAC)

Response: See response to 45-day comment N-1.4, as well as responses to 45-day comments L-3.2 and L-2.1 (regarding use of auction proceeds).

H-1.2. Comment:

Through its cap-and-trade and offsets program, California is also bringing full benefits of the clean economy transition to disadvantaged communities. California must focus its efforts on continuing to set the high-water mark for environmental integrity through its cap and trade and offset programs, and to putting auction proceeds to best use in addressing equity concerns. (IETA)

Response: Staff agrees with the comment.

H-1.3. Comment:

In submitting these comments, LADWP reaffirms its strong support of the AB 32 and SB 32 goals of expeditiously achieving substantial GHG emission reductions in a cost-effective manner that protects its ratepayers and minimizes impacts to low-income communities. (LADWP)

Response: Each of these goals is reflected in the Cap-and-Trade Program and the current amendments. The comment does not propose specific changes or recommendations on the Proposed Amendments. As such, no further response is required.

H-2. Disposition of Unsold and Consigned Allowances

H-2.1. Multiple Comments:

Cost containment should be a guiding principle for market design. Cost containment proposals should not just focus on what the state can do in the event of a sudden allowance price spike, but instead should also consider market design choices that could prevent a spike from occurring in the first place. This regulatory package includes several proposals that could result in the tightening of allowance supply and/or proposals that could increase the costs of compliance for regulated entities.

On the treatment of unsold allowances, SCE agrees with other California utilities who believe that removing allowances from the market into the APCR after two years is premature and could have the unintended consequence of significantly increasing the costs of the Cap-and-Trade program. The Cap-and-Trade program has been subject to significant uncertainty due to regulatory, judicial, and legislative controversies. A first-of-its-kind greenhouse gas market could be expected to face such challenges, and is still clearly feeling the effects of lingering uncertainty. SCE and JUG members suggest that ARB should continue monitoring market performance and allow current rule challenges to be settled to understand how demand may bounce back after additional certainty appears in the market. The mechanism to hold unsold allowances out of the market for a time should be structured to return them to the market at prices lower than the proposed APCR \$60 plus premium over the floor price. Otherwise, if unsold allowances are removed from circulation into the APCR, prices could spike higher on a rebound than they would if unsold allowances were allowed to continue in circulation in some fashion. (SOCALEDISON)

Comment:

Post-2020 Cap Setting and Allowances

In the near term, ARB should not reduce the annual GHG allowance budget from 2021-2030 by placing allowances in the APCR even if 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”.⁸⁵⁵ 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 C below and the high APCR price tier proposed by ARB and discussed in subsection D below. (PG&E)

⁸⁵⁵ Air Resources Board. Proposed Amendments to the California Cap on Greenhouse Gas emissions and Market Based Compliance Mechanisms ISOR p. 12. August 2, 2016.

Comment:

TID is opposed to removing any unsold allowances from the market and placing them in the Allowance Price Containment Reserve (“APCR”). We are very concerned that once made, this decision could not be reversed. This change is premature in light of major program changes in the near future: i.e., the new linkage with Ontario and the precipitous and substantial, economy-wide decline of the cap out to 2030. The cap decline in conjunction with the changing floor price will necessarily lead to increases in carbon prices. We also believe that the marked improvement in allowance sales in the auctions since the adoption of SB 32 may signal increased demand for the quarterly auctions.

Predictably, as a landmark, 1st of its kind program, the Cap & Trade program has experienced a host of legal and regulatory uncertainties which have prevented some participating entities from making long term emissions reductions investments. The CA Carbon market is extremely sensitive to political and legal issues, and has reacted to the surprise win of Scott Brown, the Clean Power Plan stay, and the CA Chamber lawsuit. TID urges Staff to keep these unsold allowances in the market in order to avoid a spike in compliance costs, and be mindful how short the program is expected to be post 2020. There will be ample time to make this change if under subscription continues in the quarterly auctions. As an alternative, if the Board moves forward with adjusting these allowances, TID suggests creating multiple tiers for selling allowances between the floor and current top APCR tier, this would be akin to a “speed bump” type of approach. (TURLOCKID)

Comment:

The 15-Day Changes revise the proposed amendments to section 95911(g) to exclude allowances retired for the newly designated “EIM Outstanding Emissions” from the scope of the provision. Despite numerous stakeholder comments on this matter, the 15-Day Changes leave unaltered the proposal to permanently designate allowances that are unsold for more than 24 months into the Allowance Price Containment Reserve. For the reasons set forth in the September 19 Comments, NCPA urges CARB to reconsider this proposed amendment and ensure that allowances remain available to compliance entities without unnecessary restrictions. (NCPA)

Response: Staff maintain the rationale for transferring unsold allowances to the APCR as explained in the response to the commenters’ 45-day comments. Refer to the response for H-3.2.

Further, in the first 15-Day Modifications, staff proposed retiring a portion of the unsold allowances to account for GHG emissions associated with CAISO’s Energy Imbalance Market (EIM). While CAISO is in the process of developing amendments to its EIM tariff and tracking systems, ARB staff has proposed changes to sections 95852(b)(1) and 95911(g) as a bridge to support accurate accounting of emissions resulting from electricity generation that serves

California load. ARB staff's proposed modification provides an accounting method for unsold allowances without impacting staff's initial proposal of allocating a total of 54.5 million allowances to the APCR from 2021 to 2031.

H-2.2. Multiple Comments:

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. (PG&E)

Comment:

Consignment of unsold allowances to the Allowance Price Containment Reserve (APCR) should be delayed until such allowances remain unsold for much longer than eight consecutive auctions. In our September 19, 2016 comments regarding the 45-day Cap-and-Trade amendments MID suggested that eight consecutive auctions, to be applied retroactively, is not sufficient time to wait before unsold allowances are sent to the APCR. MID and many others have stated that the newness of the program, along with the chilling effect caused by the Chamber of Commerce lawsuit challenging the legitimacy of the program have created an environment that destabilizes the operation of the Cap-and-Trade program and that any changes to its cost containment provisions in response to such an environment would be premature and detrimental to the program once its caps decline sufficiently to induce intense competition for allowances. In May 2016, just after the California Chamber of Commerce filed its lawsuit against the Cap-and-Trade program, allowances were trading on the secondary market at around

\$12.50 per allowance, much lower than the \$12.73 auction floor price. This is indicative of marketers liquidating their positions and cannot be expected to continue once the program has stabilized. To make a far-reaching cost containment change based on such behavior would be a mistake. (MODESTOID)

Comment:

The retirement of unused allowances further constricts the market. While this proposal might be in reaction to the limited participation in recent auctions, CCEEB rejects the proposal as it would have substantial unintended consequences. It would greatly reduce liquidity which can lead to market manipulation; i.e. decreased liquidity results in volatility. As previously stated, litigation and lack of post-2020 certainty are impacting participation in recent auctions. However, these issues will likely be addressed in the near future. Measures to tighten the market are premature given the external uncertainty that has affected the Program in recent years, and could result in substantial increase in costs for Californians as market certainty is restored and the market naturally tightens on its own during the 2021-2030 timeframe. (CCEEB)

Response: See response to 45-day comment H-3.2.

H-2.3. Comment:

The proposal to retire unsold allowances to the Allowance Price Containment Reserve (APCR) after a period of 24 months remains problematic. This approach may lead to future price spikes in the short to mid-term, which could raise political concerns around program efficacy due to market volatility. IETA supports the modification to allocate resold allowances in advance of newly allocated allowances to successful auction participants...

COST-CONTAINMENT & APCR

ARB has proposed significantly modifying the structure and pricing of the APCR. Developing and implementing a program structure that will promote a robust market with strong participation and liquidity, while maintaining political palatability to both California constituents and government, is of paramount importance to the long-term health of California's cap-and-trade program.

California's current regulatory structure only allows unsold allowances to be offered back to the market once two auctions are fully subscribed in a row. If auctions remain even marginally undersubscribed over the next few quarters, large volumes of allowances could be allocated to the APCR without giving the market a second opportunity to purchase this volume. IETA cautions ARB that implementing this design feature could create an unintended result of short-term market pricing spikes due to a significant allocation of unsold allowances to the APCR. Having significant oscillation in market pricing between the auction floor and APCR soft pricing ceiling, over a relatively short period of time, could bring the cap-and-trade program under significant scrutiny, both by industry and California consumers.

In light of the above observations, we recommend that ARB consider lengthening the time period for allocation of unsold allowances to the APCR. Increasing the timeframe for consideration of implementation for this mechanism from 2018 to 2020 will allow the market time to receive both regulatory and legal certainty around the continuation of cap and trade post-2020. This clarity will address the reduced market participation and liquidity issues that have arisen in the short-term in California and created (government) concern around auction revenue generation.

By allowing additional timing flexibility for unsold allowances before allocation to the APCR, the market will be given an opportunity to purchase these compliance units again under the standard auctions at a price reflective of current market fundamentals. California can thus avoid artificially creating significant market pricing volatility; an unintended consequence of a regulatory change intended to incent consistent participation at auction. (IETA)

Response: See responses to 45-day comments H-3.2 and H-3.6.

H-2.4. Comment:

5. Unsold state allowances should not be consigned to the Allowance Price Containment Reserve

The August 2, 2016 Staff Report included a proposal to consign allowances that remained unsold for 24 months to the allowance price containment reserve (APCR). The 15-Day Changes modify the text in this provision, but do not respond to stakeholder concerns about the adverse impacts that could result from permanently removing these allowances from the regular market prematurely. M-S-R urges CARB to amend its recommendation to move these unsold allowances into the APCR, or at a minimum, extend the time period during which the allowances remain unsold before moving them. (M-S-R)

Response: See responses to 45-day comments H-3.2 and H-3.3 regarding unsold allowances. The proposed 15-Day changes to section 95852(b)(1)(D) creates a pathway by which unsold allowances may be retired to cover emissions in the CAISO Energy Imbalance Market (EIM) that will not be assigned to a particular covered entity. Each year ARB will determine the amount of such uncovered emissions and retire the appropriate number of unsold allowances instead of sending them to the Reserve. The alternative would be to directly remove the EIM allowances from the annual allowance budgets. This would directly reduce the number of allowances going to market, even when the market is tight. Staff understands that further modifications may be needed once further data on EIM emissions and unsold allowances are available.

H-3. Allowance Price Containment Reserve (APCR)

Price Tiers

H-3.1. Comment:

ARB Should Ensure Post-2020 Prices Cannot Exceed Acceptable Levels

ARB should incorporate program design features before 2021 that ensure post-2020 allowance prices cannot exceed a maximum level deemed acceptable by ARB. This could be done by developing a mechanism to refill the Allowance Price Containment Reserve (APCR) if it is depleted. ARB has already proposed limited borrowing from future budgets through 2050 to refill the APCR as a buffer, but a firm price ceiling, as described in PG&E's previous comments, would improve the economic sustainability of the Program.⁸⁵⁶ Taken together, this firm price ceiling and existing price floor would provide a price collar for the Program.

A firm price ceiling would enable ARB to provide the allowances needed – via allowance sales at the ceiling price – to defend its maximum allowance price level. We recommend prioritizing the use of revenue from additional allowance sales for the purchase and retirement of an equivalent or greater quantity of GHG instruments (i.e., offsets or allowances) from credible GHG programs in other jurisdictions in order to maintain global GHG integrity.

It is in the interest of all Californians to avoid the potential for skyrocketing, unsustainable program costs that would lead to high prices for customers and could lead to negative environmental outcomes if the Program were to be suspended. (PG&E)

Response: The commenter's requests to establish a firm price ceiling and to establish a mechanism to replenish the APCR if depleted are outside the scope of the proposed regulatory amendments in this rulemaking. ARB staff is dedicated to continuing to monitor market price points for both the auction and cost containment market design features, but declines to make the requested changes at this time. Please also see the response to 45-Day comment H-1.5.

H-3.2. Comment:

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

⁸⁵⁶ Pacific Gas and Electric Company. RE: April 5, 2016 Cost Containment Workshop. April 22, 2016. <https://www.arb.ca.gov/lists/com-attach/6-sectorbased3-ws-BXVXNIYyVVIQNQVq.pdf>

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. (PG&E)

Response: See response to 45-day comment H-4.7.

Miscellaneous

H-3.3. Comment:

MARKET REFORMS ARE NECESSARY

In order to ensure market stability and cost-containment, there need to be reforms made to the Allowance Price Containment Reserve (APCR). Post-2020 emissions reductions will constrain the market as the cap declines at a more rapid rate. Price containment in the APCR is necessary if the reserve is to be a true cost-containment mechanism. We recommend that there be further consultation with market experts in order to make necessary reforms to ensure the stability of the market and maximize cost-containment. (CALCHAMBERCOMMERCE)

Response: The commenter submitted the same comment as part of the 45-day comment period. See response to 45-day comment H-4.13.

H-3.4. Comment:

SMUD supports some of the components in the proposed amendments, including the 15-day language, which add to and alter the APCR structure by:

- leaving any unused allowances in the current APCR in place after 2020; and
- allocating after 2020 to the APCR based on the comparison of expected actual versus capped emissions in 2020.

However, SMUD is concerned about the proposal to place unsold ARB allowances into the APCR, combined with collapsing the three tiers into one price that is related to the escalating floor price. SMUD proposes to carry over unsold ARB allowances to future years at something close to future year's market clearing prices. SMUD is concerned that removing these allowances from the general pool of auction allowances would restrict future supply that would be cleared at prices below the APCR.

SMUD supports the Carbon Market Compliance Association's comments to establish "speed bumps" to slow or stop market price increases rather than relying solely on the collapsed APCR. SMUD proposes that speed bump tiers be set at some reasonable multiple of the floor price where the ARB will have the flexibility to release an appropriate amount of allowances into the market. In addition, SMUD proposes that at the highest speed bump (similar to the collapsed APCR price in the proposed amendments), the ARB include a structure that allows additional supply to be brought quickly into the market to allow time for investments to reduce demand. This additional supply could come from borrowing from future allocations, or from including additional offsets in some fashion, or similar measures, in order to preserve the emission reduction goal set by the cap.

For example, the current Cap and Trade Regulation already allows for borrowing from future vintages if there are insufficient allowances available at the highest price APCR Tier. The proposed amendments would extend the Cap-and-Trade program with explicit allowance budgets through 2031 (in Table 6-2). This borrowing provision provides less market price containment as years pass, as there are fewer future years from which to borrow. The ARB could extend this borrowing concept beyond the proposed 2031 vintage by including borrowing from the anticipated post-2031 Cap-and-Trade program (or similar structure established to reach the 2050 goal of reducing carbon emissions to 80% below 1990 levels). One way to do this without explicit allowance budgets for each year is simply to tie the borrowing to the indicated 2050 budget level of 66 million allowances (20% of the 1990 level assuming the program has the same scope as today's program). Assuming this level of allowance budget for every year after 2031 would be conservative, and would potentially yield another 125 million allowances to be sold at the highest APCR price (10% of annual budget times 19 years).

Another possibility is opening up offset supply as the highest APCR price is accessed, either by exempting some offsets from the limit if they have certain in-state benefits as proposed below or by facilitating full use of the 8% offset limit as proposed below. Other sources of compliance instruments that could be brought to bear should the APCR highest tier be accessed could be any unused allowances in the VRE or similar accounts and any allowances or that were retired but not associated with covering a compliance requirement (e.g. voluntarily retired allowances).

Combined, these proposals will provide a safety net against substantial price increases under the Cap-and-Trade program. Significant price volatility and/or extreme prices will

undermine the viability of the Cap-and-Trade program and may eliminate any benefits California expects from the program. (SMUD)

Response: Staff believes that a single price tier maintains an adequate cost containment design that does not unduly tighten the market. As stated in the response to 45-day comment H-4.1, staff expects the APCR to hold over 120 million allowances from the first three compliance periods at the start of 2021, and this quantity along with the allowances allocation to the APCR from 2021 to 2031 is sufficient to meet the cost containment needs of the Program over this time.

The comments related to borrowing and exempting some offsets from the limit to expand the supply of the allowance budget in the post-2020 Program are beyond the scope of the amendments proposed in this rulemaking, and a response is therefore not required.

H-4. Post-2020 GHG Emissions Budget

H-4.1. Multiple Comments:

SMUD supports continuing California's leadership on climate issues by continuing reductions of GHG emissions beyond the 1990 level California is poised to achieve in 2020.

Comment:

SCE also supports ARB's post-2030 annual economy-wide cap-setting methodology. (SOCALEDISON)

Comment:

POST-2020 CAP-SETTING

IETA supports the proposed use of a "straight-line" cap reduction path from 2020 to 2030 and clarity on the allowance budget to 2050. Certainty on future allowance supply represents a cornerstone of a robust carbon market, providing transparency to participants and driving market liquidity and participation...

Extending cap levels beyond 2020 plays a critical role in contributing to the continuation of California's market program. IETA supports the use of a "straight-line" cap reduction path from 2020 to 2030. (IETA)

Response: Thank you for the support. See also response to 45-day comments H-5.1 and H-5.3.

H-4.2. Comment:

IETA also applauds ARB for proposing to set initial allowance budgets through 2050. This signals a long-term trajectory of California's market program and helps to inform long-term investment decisions. (IETA)

Response: Thank you for the support. See also response to 45-day comment H-5.3.

H-4.3. Multiple Comments:

LACK OF AUTHORITY FOR POST-2030 ALLOWANCE BUDGETS

Despite the recent passage of SB 32 (Pavley), and beyond the lack of authority for a cap-and-trade program 2020, there is certainly no authorization to establish a GHG emission reduction limit for 2050. We recommend that ARB remove post-2030 caps from this rulemaking. (CALCHAMBERCOMMERCE)

Comment:

Lack of Authority For Post 2030 Allowance Budgets:

Despite the 2016 passage of SB 32 (Pavley), and beyond the lack of authority for a cap-and-trade program 2020, there is certainly no authorization to establish a GHG emission reduction limit for 2050. We recommend that ARB remove post-2030 caps from this rulemaking. (CCPC)

Response: See responses to 45-day comments K-1.8 and K-1.11.

I. DOMESTIC AND INTERNATIONAL LINKAGE

I-1. Linkage in General

I-1.1. Multiple Comments:

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)

Comment:

We applaud proposed support for cross-border linkages, including full and partial program linkages that create broader markets and a wider range of abatement opportunities. These expanding market links will only strengthen California's climate leadership while sharing cost burdens and benefits of reducing GHGs with partner jurisdictions. (IETA)

Response: Thank you for the support.

I-1.2. Comment:

The Climate Trust applauds ARB's efforts to ensure the cap and trade program continues to facilitate linkages with other jurisdictions. Mitigating greenhouse gas emissions requires a multi-jurisdictional effort. A valuable cost-effective approach involves linking with other jurisdictions providing for a more efficient market that can

drive the costs of compliance down. Therefore, the changes to the program that facilitate promotion of market linkages are a step in a right direction. (CLIMATETRUST)

Response: Thank you for the support.

I-1.3. Comment:

6. Linkages with other GHG programs are properly subject to a formal stakeholder process

The 15-Day Changes include further modified text to proposed new section 95945. This additional language would require that the Board only approve a “retirement-only” agreement with an external GHG program after public notice and an opportunity for public comment. M-S-R supports CARB’s explicit recognition that any such linkages must be part of a public process that involves affected stakeholders. M-S-R remains concerned, however, that expanded linkages could adversely impact compliance entities; to that end, linkages with other emissions-based programs that do not afford California compliance entities access to additional compliance instruments while allowing California compliance instruments to be retired for other than the cap-and-trade program should be avoided. To the extent that the 15-Day Changes do not address the remaining concerns raised by M-S-R and other stakeholders regarding these new linkage options and the importance of ensuring compliance entities in California’s program have adequate access to compliance instruments, M-S-R urges the Board to direct that they be address in subsequent 15-day changes. (M-S-R)

Response: See responses to 45-day comments I-1.1, I-3.1, I-3.2, I-3.3, and I-3.4.

I-2. Linkage with Ontario

I-2.1. Multiple Comments:

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. (PG&E)

Comment:

Linkage with Ontario and External GHG Emissions Trading Systems & Programs

Throughout ARB’s robust consultation process, IETA has been a consistent voice advocating for the multitude of benefits of cross-border linkage. We applaud Staff’s recognition of linkage benefits in its Initial Statement of Reasons (ISOR) report.⁸⁵⁷ Linkage is a valuable cost-containment mechanism that increases compliance flexibility and market liquidity, thereby driving down program costs while driving up clean projects, jobs, and investment opportunities.

⁸⁵⁷ ARB. [Staff Report: Initial Statement of Reasons](#), pg. 17.

In particular, IETA applauds the leadership California has shown during the development of Ontario's compliance cap-and-trade program, launched on 1 January 2017. ARB's deep and frequent engagement with Ontario officials, through the province's design and implementation process, will go a long way towards ensuring the future California linkage process goes smoothly in 2018. This will also reap benefits as parties seek structural and policy alignment post-2020. California's commitment to expanding trading partners is also important given the rising number of North American jurisdictions, including Mexico, that are proposing/considering climate market mechanisms that link, fully or partially, to the WCI market. (IETA)

Response: Thank you for the support.

I-3. One-Way Linkages with Other Jurisdictions

I-3.1. Comment:

IETA strongly supports the two new linkage options proposed by ARB – neither of which would require the same level of operational integration as the California-Québec (and soon to be Ontario) style program. As IETA has consistently communicated across North America, the inherent flexibility of WCI's model creates an ideal framework to functionally embrace and enable these proposed types of one-way unit flows. (IETA)

Response: Thank you for the support.

I-3.2. Multiple Comments:

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. (PG&E)

Comment:

The Proposed Amendments included new options for one-way linkages with other emissions reduction programs. As NCPA noted in the September 19 Comments, the state should continue developing potential trading partners, but actual linkages with other programs should only occur when those programs meet *all* the existing standards and provide California entities the same access to comparable compliance instruments from their jurisdiction as they would have to California compliance instruments.

The 15-Day Changes provide clarification to proposed new section 95945 regarding "Retirement-Only Agreements With External GHG Program." NCPA fully supports the inclusion of language in section 95945(a) that linkages with other emissions-based programs must be subject to stakeholder review and comment before the Board can approve them. To the extent that the 15-Day Changes do not address the remaining

modifications discussed in the September 19 Comments, NCPA urges CARB to ensure that those additional revisions are reflected in subsequent 15-day changes before approving the new provisions. (NCPA)

Response: Thank you for the support. See also responses to 45-day comment I-3.3 and I-3.4.

I-4. International Sector-Based Forest Offsets

I-4.1. Comment:

Additionally, 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 diminish 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. (PG&E)

Response: The comment is outside the scope of the proposed amendments. Please see also responses to 45-day comments I-4.1 and I-4.2.

I-4.2. Comment:

Do not pursue or include reducing emissions from deforestation and forest degradation (REDD) international offsets in the Scoping Plan. (EJAC)

Response: The comment is outside of the scope of the proposed amendments. Please see also response to 45-day comment I-4.4.

J. SUPPORT FOR THE PROPOSED AMENDMENTS

J-1.1. Multiple Comments:

IETA applauds ARB's recognition that a fully-functional market mechanism is a vital, cost-effective cornerstone tool in California's climate policy architecture. As the leading voice for the world's international business community on climate markets and finance, IETA is a staunch supporter of California's strong commitment to cap-and-trade and tangible market links with other jurisdictions.

IETA remains a consistent, progressive multi-sector business voice that supports climate action and strongly believes that market solutions as the best means to: drive climate action and investment across key sectors of the economy; meet climate targets cost-effectively; and accelerate low-carbon transformative economic and societal changes. Our members include some of California's biggest emitters, entrepreneurs focused on delivering climate solutions and greenhouse gas (GHG) reductions, and

markets-focused (NGO) registries that represent the backbone of environmental integrity in California's cap-and-trade market and international markets.

IETA encourages California to stay the course and maintain its cap-and-trade program. The program has resulted in significant environmental benefit to the State and global climate, and California arguably occupies this global and national position of climate leadership in large part because of this market-based program. The destabilizing impact of California changing course on this critical policy now would be significant and detrimental to progress on climate action at home and beyond...

IETA reaffirms our strong support for California's cap-and-trade program, and our community encourages the State to stay the course on its world-leading market approach to effectively, efficiently, and fairly reducing GHG emissions. (IETA)

Comment:

Though the proposed regulatory changes at hand assume an uninterrupted future existence of the Program, staff has been evaluating alternative options to achieve the 2030 Target Scoping Plan goals. SCPPA believes altering course now would be an even more costly and diversionary endeavor; we support the continuation of the Cap-and-Trade Program post-2020. SCPPA believes that this market-based mechanism is the most cost-effective means of achieving GHG emissions reductions throughout the state. The Program offers the significant benefit of promoting and implementing Greenhouse Gas Reduction Fund projects and programs across the state – particularly in disadvantaged communities – that are designed to simultaneously provide economic and public health co-benefits. The Program as currently constructed also allows our Members to pass the value of allowance allocations directly to their customers. These benefits flow through to all of our Members' customers, including those in disadvantaged communities. The continuation of a well-designed Cap-and-Trade Program supports public utilities' ability to provide Californians with affordable energy while still maintaining a sustainable path towards the 2030 statewide GHG emission reduction goal. (SCPPA)

Comment:

PG&E maintains that the Cap-and-Trade Program is a robust tool for achieving environmental goals while maintaining a vibrant economy. However, the design of the Program must be finely tuned to achieve this end, and PG&E reiterates a number of market design recommendations that should be considered to maintain a Program that is both an environmental and economic success...

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. (PG&E)

Comment:

NCPA supports continuation of the Cap-and-Trade program (Program) and believes that it should remain a cornerstone of California's climate strategy...

NCPA and its member entities have demonstrated their commitment to helping California achieve its greenhouse (GHG) goals and objectives, and remain committed to doing their share to reduce statewide GHG emissions. NCPA supports continuation of the state's landmark cap-and-trade program, inclusive of key design features such as the allocation of allowances directly to electric distribution utilities (EDUs) for the benefit of their ratepayers, as part of the state's strategy to achieve the desired climate changes and GHG reductions. As more fully discussed in NCPA's September 19, 2016 comments on the Proposed Amendments, the electricity sector plays a crucial role in the state's climate strategy and is responsible for effecting GHG reductions through different programs and measures.⁸⁵⁸ Achieving California's laudable climate objectives is important, but ensuring the continued provision of safe, reliable, and reasonably priced electricity for the residents and businesses in NCPA members' service territories is also important. For these reasons, while NCPA continues to view the cap-and-trade program as a critical tool to reduce GHG emissions in the most cost-effective manner, changes to the program that impact compliance costs for EDUs must be carefully addressed. (NCPA)

Comment:

TID remains committed to working towards the State's climate and clean energy goals, and generally supports the extension of Cap & Trade, notwithstanding numerous implementation concerns outlined below, and offers the following comments on the recently released Draft Cap & Trade Regulations. (TID)

Comment:

The Offset Group supports the continuation of the Cap-and-Trade Program post-2020 and believes that this market-based mechanism is the most cost-effective and certain way for California to achieve its GHG emission reduction goals. Individual member letters will address the various technical aspects of the proposed amendments, but our unified message conveyed is that the existing program (with its current offset usage limit) is working and provides the necessary incentives to realize real and verifiable GHG emission reductions that would not otherwise be achieved under the Cap and Trade Program. (ADHOCOFFSETS)

⁸⁵⁸ Comments of the Northern California Power Agency on Proposed Amendments to the Cap-and-Trade Program Regulation, September 19, 2016; <https://www.arb.ca.gov/lists/com-attach/89-capandtrade16-BWtdOFaHJWMLUgdk.pdf>. NCPA does not reiterate those comments herein, but notes that the 15-Day Changes do not address all the issues raised in the September 19 comments, and urges staff to continue to work with stakeholders on resolution of those outstanding issues, as well.

Comment:

We fully support CARB's work to reduce greenhouse gas emissions in the state and the continuation of the Cap and Trade program post 2020. (COVANTA)

Response: The commenters express support for the proposed amendments, in particular the extension of the Cap-and-Trade Program beyond 2020. Staff appreciates the commenters' support. Some comments reference recommendations on various market design features – those recommendations, and staff's responses, are dealt with separately elsewhere in this FSOR.

J-1.2. Multiple Comments:

SCE supports a well-designed Cap-and-Trade program to help the state achieve its post-2020 goals. A well-designed Cap-and-Trade Program can help keep total program costs down while achieving environmental goals. (SOCALEDISON)

Comment:

Overall, CMTA believes that a well-designed cap and trade is the most cost-effective method for achieving GHG emissions reductions while limiting the impact to California's economy. Enabling companies to choose the most economical method for reducing emissions will limit the negative effects of imposing the compliance costs on California manufacturers when no other competitive market also imposes such costs on their manufacturers. (CMTA)

Comment:

M-S-R and its member agencies each support continuation of the cap-and-trade program as a key element of the state's overall emission reduction plan, and a vital tool for compliance entities to achieve the mandated reductions in the most cost-effective means possible. (M-S-R)

Comment:

Air Liquide generally supports CARB's proposed rulemaking. (AIRLIQUIDE)

Response: Thank you for the support.

J-1.3. Comment:

With SB 32 (Chapter 249, Statutes of 2016) now law, CCEEB believes that additional emphasis on Cap-and-Trade is necessary to achieve cost-effective emission reductions and to send a clear market signal to facility operations and projects. CCEEB supports a well-designed Cap-and-Trade Program as the most economically efficient, transparent, and environmentally effective policy for California to achieve statewide greenhouse gas emission reductions and meet the 2030 goal.

The compliance flexibility provided by the Cap-and-Trade Program allows California businesses to select reduction strategies that best suit their unique needs and evolving

circumstances, while delivering real emission reductions more efficiently and at less cost than direct measures. Cap-and-Trade continues to achieve GHG emission reductions while sending a clear and transparent price signal throughout California's economy. This in turn prompts behavior change that reduces emissions and spurs the investment and commercialization of advanced technologies. Additionally, Cap-and-Trade provides the potential to export the policy to other jurisdictions through linkage or sector-based offsets, providing a real platform for California to realize its goals as a climate leader.

Some of the proposed regulatory amendments, such as those requiring the release of market sensitive data, diminish the ability to use offsets, potentially retiring unused allowances, and sequestering unsold allowance into the Allowance Price Containment Reserve, set California on a limited path with narrow solutions that will ultimately be costlier, limit technological development, and lead to economic and emissions leakage. Our post-2020 policies should support the opportunity for new, emerging technologies and control strategies, and allow California to do what it does best – innovate.

Moreover, California cannot mitigate climate change alone. Policies that reduce greenhouse gases in the most economically efficient way will encourage other jurisdictions to link to California. Adding extraneous policies, stringency, or complexity that does not enhance the efficacy of the program will discourage rather than encourage other states, provinces, and countries to join the fight against climate change. Given today's economic realities, pursuing high cost program features that constrain Cap-and-Trade will only serve to further isolate California from potential sub-regional, national, and international partners. Other jurisdictions will not follow costly programs that create unsustainable economic pressures and drive business away. Even worse would be policies that limit or outright bar California from joining in partnerships with other jurisdictions, either through linkage or use of offsets. Insular policies may achieve in-state goals, but they will not solve global climate change.

ARB, with public input and strong collaboration with coalitions such as CCEEB, has spent the last decade developing a strong Cap-and-Trade Program. In light of SB 32's even more ambitious carbon reduction targets, now more than ever, a well-designed Cap-and-Trade Program is needed to help California meet its environmental goals while maintaining a strong economy. (CCEEB)

Response: The commenter offers support for the proposed amendments to continue the Cap-and-Trade Program beyond 2020. ARB staff appreciates the support. The portions of the comment which raise concerns with the proposed regulatory amendments, such as those requiring the release of market sensitive data, diminish the ability to use offsets, potentially retiring unused allowances, and sequestering unsold allowance into the Allowance Price Containment Reserve, are addressed elsewhere in this document. So, in order of the specific concerns presented, see responses to 45-day comments K-1.5 (regarding

market sensitive information), E-1.1 (no changes to offsets limit), and H-3.2 (unsold allowances and retirements).

J-1.4. Comment:

Calpine previously commented on ARB's proposed amendments to the MRR and Cap-and-Trade Regulation and proposed compliance plan for the federal Clean Power Plan, affirming ARB's authority to continue with implementation of the Cap-and-Trade Program beyond 2020 and the proposal to rely upon the Cap-and-Trade Program to satisfy the requirements of the federal Clean Power Plan, which Calpine is currently defending alongside ARB in the U.S. Court of Appeals for the District of Columbia Circuit. Calpine also commented on ARB's public workshop held on October 21, 2016 concerning the Cap-and-Trade Regulation, reiterating Calpine's support for continuation of the Cap-and-Trade Program and offering its view as to why extension of the Program beyond 2020 is consistent with and responsive to California's enactment of Assembly Bill ("AB") 197 and Senate Bill ("SB") 32. (CALPINE)

Response: Thank you for the support.

J-1.5. Comment:

Again, we support ARB's continuation of Cap-and-Trade and the use of offsets to meet its ambitious 2030 targets. (ORIGINCLIMATE)

Response: Thank you for the support.

J-1.6. Comment:

Bluesource greatly appreciates the Air Resources Board staff's drive to make continuous improvements to this landmark program and is supportive of staff's recommendation to extend it beyond 2020 in today's release of the draft Scoping Plan. (BLUESOURCE)

Response: Thank you for the support. However, the Scoping Plan is outside of the scope of this rulemaking.

K. OPPOSITION TO THE PROPOSED AMENDMENTS

K-1.1. Comment:

Cap-and-Trade must be eliminated. (EJAC)

Response: See response to 45-day comment K-1.3.

K-1.2. Comment:

CalChamber strives to remain a productive stakeholder throughout the AB 32 implementation process as well as in the future with post-2020 climate policies, in order to advance the greenhouse gas (GHG) emission reduction goals in the most cost-effective manner while protecting California businesses and allowing for economic

growth across all sectors of the economy. We have long maintained that if designed properly, a market-based mechanism has the ability to garner significant GHG reductions in a cost-effective manner.

A cap-and-trade program will be a more cost-effective approach than command and control and less likely to discriminate unfairly against particular industrial sectors. California's greenhouse gas reduction laws post 2020 will be unworkable without a well-designed market mechanism. The command and control measures that would be used to achieve a 2030 GHG emission reduction target of 40% below 1990 levels will be harsh and severely impact the quality of life of Californians. This will require cutting per capita GHG emissions nearly in half over ten years, after already achieving the easiest and most cost effective reductions.

Governor Brown has noted that an extension of cap-and-trade post 2020 is unfinished business. In order for there to be an extension, there needs to be legislative authority. A market mechanism can be adopted with a simple majority vote of the California Legislature, however, if the CARB is looking for a revenue stream beyond the cost of administering the program, this will require a supermajority in order to approve the tax.

Our comments below include concerns for some design flaws and recommendations to modify elements to ensure an operable, cost-effective program.

(CALCHAMBERCOMMERCE)

Response: ARB staff appreciates the commenter's general support for cap-and-trade. With respect to the portion of the comment expressing concerns over legislative authority, see response to 45-day comment K-1.8. This comment also references more specific concerns by the same commenter; those specific comments, and staff responses, are included elsewhere in this FSOR.

K-1.3. Comment:

Assembly Member Eduardo Garcia (D-Coachella), the author of AB 197, testified in Assembly Natural Resources Committee on August 24, 2016:

"I also want to just clearly state that we to are supportive of the Cap-and-Trade program, the leadership of the Senate who moved the bill out this week is in support of the Cap-and-Trade program, the leadership of the Assembly is in support of the Cap-and-Trade program, the governor of the state is in support of the Cap-and-Trade and has asked that 197 be sent to his desk as a package with SB 32. So, I wanted just to state that the intention is by no means to tamper with the Cap-and-Trade program."

In an August 31, 2016 letter to the Assembly Journal, Assembly Member Eduardo Garcia stated, "*It is my intent that nothing in Section 38562.5 shall be interpreted to preclude ARB from adopting any market-based compliance mechanism pursuant AB 32.*"

[The commenter attached an August 2016 letter from the author of AB 197 to the assembly clerk which includes the above sentence.]

Based on these statements, CCEEB urges ARB staff to be measured in its response to AB 197 and limit proposed amendments to the Mandatory Reporting Regulation and Cap-and-Trade Program at this juncture. Now is not the time to propose radical departures from current program design based on inference of intent without explicit statutory guidance. It is clear that Assembly Member Eduardo Garcia, the Legislature, and the governor did not intend for ARB to substantially deviate from the existing Cap-and-Trade design.

Unfortunately, the proposed amendments would result in some troubling changes in the program. Issues of concern include a reduction of offsets, shifting the cost burden through reduction of industry assistance, and retiring allowances from the pre-2020 Allowance Price Containment Reserve (APCR). It is premature to make these changes prior to completion of at least two more compliance periods, when the full scope of the program will have been in effect and back-loaded elements of the Scoping Plan implemented. While AB 197 does list new priorities for ARB to consider when making changes to the Cap-and-Trade program, these do not supersede the existing priorities, listed in AB 32, of cost-effectiveness and technological feasibility. Additionally, we note that at the October 21, 2016 workshop, staff acknowledged that the Cap-and-Trade Program already helps achieve direct emissions reductions.

The Cap-and-Trade proposal appears to be designed with a “cost burden” assumption that higher compliance costs will result in increased direct emissions reductions. CCEEB disagrees with this premise. Rather, CCEEB believes that the post-2020 program needs to be designed to *increase* cost effectiveness, both as a means to maximize GHG emissions reductions (i.e., “biggest bang for the buck”) and as a way to prevent emissions and economic leakage in the post-2020 program as the declining cap drives up the cost of carbon.

Nancy McFadden, executive secretary for the governor, stated on August 4, 2016, “Let this be clear: We are going to extend our climate goals and Cap-and-Trade program – one way or another. The governor will continue working with the Legislature to get this done this year, next year, or on the ballot in 2018.” This statement stands, and while SB 32 sets a new 2030 climate goal, there is still need to explicitly adopt Cap-and-Trade. Legislation will likely be introduced in the 2017-18 Legislative Session that will explicitly address this; it is prudent to hold off on speculating legislative intent until there is legislation dictating how Cap-and-Trade should be designed post-2020. (CCEEB)

Response: The comment expresses support for the continuation of the Cap-and-Trade Program, but also expresses concerns with some concepts that are both inside and outside the scope of the current rulemaking. Some of these concepts were discussed at informal staff workshops (e.g., retiring APCR allowances pre-2020, reducing the offsets quantitative usage limit). Those

changes were not proposed in the 45-day amendment package and therefore are beyond the scope of this rulemaking. Other concerns address AB 197 implementation and a desire for increased cost effectiveness. The comment does not seek specific modifications to the proposed 15-day changes, and a more direct response is not required. For responses related to AB 197, see response to 45-day comment L-1.1. See response to 45-day comment K-1.8 regarding legal authority.

L. ALTERNATIVES TO THE CAP-AND-TRADE PROGRAM

L-1. GHG Emissions Pricing Alternatives

Support for Carbon Fee

L-1.1. Comment:

A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. (EJAC)

Response: See responses to 45-day comments L-2.2 and L-3.2.

L-2. Multiple, Mixed or Additional Strategies

Alternatives to Cap-and-Trade

L-2.1. Comment:

The Scoping Plan Economic Analysis must consider carbon tax, command and control regulation, and Cap-and-Dividend or Fee-and-Dividend. Cap-and-Trade must be eliminated. (EJAC)

Response: See response to 45-day comment L-3.1.

L-2.2. Comment:

Add AB 197 and SB 350 as a Known Commitments for this sector... (EJAC)

Response: This portion of the comment appears to have been submitted in reference to the ongoing 2017 Scoping Plan Update process. It is unclear how this would fit within the current rulemaking, and staff therefore believes it is outside the scope of this rulemaking. Nonetheless, please see response to 45-day comment L-1.1 regarding AB 197.

L-2.3. Comment:

Develop a unified policy similar to (but better constructed than) CAPCOA's for trading GHG credits among districts. Delete the following sentence: "Where further project design or regional investments are infeasible or not proven to be effective, it may be appropriate and feasible to mitigate project emissions through purchasing and retiring

carbon credits issued by a recognized and reputable accredited carbon registry.” CAPCOA is creating a new carbon market that EJAC has raised concerns about, and it should not be authorized by being in the Scoping Plan. (EJAC)

Response: This portion of the comment appears to have been submitted in reference to the ongoing 2017 Scoping Plan Update process. As such, it is outside the scope of this rulemaking.

L-2.4. Comment:

Tier pricing for allowances for facilities in EJ communities, making it more expensive to pollute in those communities. (EJAC)

Response: See response to 45-day comment L-3.3.

Requested Additional Features

L-2.5. Comment:

A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program.

- a. Increase enforcement of existing environmental and climate laws, increasing penalties for violations in DACs.
 - b. Establish a state run “Carbon Investment Fund” allowing the private financial sector to invest in Carbon Futures. Pay dividends through enforcement fines, permit fees and carbon tax receipts...
 - d. Place individual caps on emission sources, rather than using a market-wide cap. Set up a per-facility emissions trigger that will tighten controls when a certain level is reached.
 - e. Establish a moratorium on refinery permits.
 - f. Set goal of 50% emissions reduction in Oil and Gas sectors by 2030. Aggressively reduce emissions from these sectors, including fugitive and methane emissions from extraction and production.
 - g. Put emissions caps on the largest polluters...
 - j. Do not allow regulated entities to apply for California Climate Investments funding...
- (EJAC)

Response: See response to 45-day comment L-3.2.

M. PUBLIC PROCESS

M-1. Time to Respond

M-1.1. Comment:

As expressed in prior public comments and letters, SCPPA is concerned with the incomplete nature of these draft regulations. ARB staff has again flagged a number of potential areas for future 15-day changes. Though potentially within the scope of this rulemaking, such material changes are outside the spirit, and potentially letter of the law, as it relates to California's public processes. 15-day amendments should be limited to clarifications and non-substantive changes to the regulations when compared to the initial 45-day language. The scale and importance of the changes being proposed in this 15-day amendment package are historically out of line. Furthermore, highlighting these possible additional policy changes distracts stakeholders from providing comments on the actual proposed language changes—such time is already limited for full analysis.

Again, we stress the importance of providing a complete draft of the regulations and thoroughly vetting policy shifts with stakeholders to ensure the feasibility and collective interaction of all of the changes. This supports transparency and facilitates a fully-informed decision-making process. While many of the proposed revisions have been discussed broadly during a number of public workshops, most of the critically important details are just now being provided. These need to be evaluated on their own, as well as in relation to other aspects of the Program, MRR, and the numerous other regulations facing utilities – including the California Environmental Quality Act. Even now, a number of legislative and regulatory uncertainties lay ahead at both the federal and state government levels, many of which could drastically affect the energy policy landscape...

We support staff in its efforts to solicit well-timed stakeholder feedback. With that said, we believe that additional time for stakeholder review and consideration of the weighty proposals would benefit all involved in the refinement of the Program and MRR regulations. As 15-day language is released in the future, it is requested that ARB highlight the changes as compared to previously released versions of the regulation and present the regulation in its entirety (with clearly noted updates) for stakeholder review, including how the California Environmental Quality Act (CEQA) may be implicated as California seeks to meet ambitious climate change and renewable energy goals. This will support stakeholders in providing a more comprehensive analysis of all program components and the interactive effect amongst ARB's own policies as well as those of other agencies (e.g., the California Energy Commission's Renewables Portfolio Standard). In addition, SCPPA fully supports extended review times, as provided with the release of these amendments, and robust public discussions on any future modifications to the proposed provisions. (SCPPA)

Response: See response to 45-day comment M-1.1.

M-1.2. Comment:

ARB's schedule for developing the 2030 Target Scoping Plan and updating the GHG Cap-and-Trade Regulation appear to be on a similar timeline such that ARB will likely consider adoption of both in spring 2017. However, much of the data used in the Scoping Plan process would also be used as the basis for developing the post-2020 allowance allocations for the updated Cap-and-Trade Regulation. Unfortunately, this data has just been released this morning. As a result, LADWP believes that ARB should allow a reasonable amount of time after the Scoping Plan is adopted (e.g., at least 90 days) to further develop amendments to the Cap-and-Trade Regulation in light of the conclusions made in the Scoping Plan process (LADWP)

Response: See response to 45-day comment M-1.1.

M-1.3. Multiple Comments:**15-Day Comment Period:**

As stated by CCPC, in September and November 2016 comments, we believe a well-designed cap-and-trade program can become an effective regulatory program to reduce emissions in a cost effective manner that maintains the competitiveness of California's businesses – but how that's accomplished will make or break California's economy. We remain concerned that the use of 15-day comment periods is insufficient for stakeholders to properly review and add constructive substantive comments for such an integral part of California's climate change policies. We recommend ARB Board directs staff to work within the 45-day comment period framework(s) moving forward to ensure the end product is the best designed and can be sustained. (CCPC)

Comment:

Air Liquide has previously commented that industrial assistance factors should not be set as part of a 15-day notice process, and should instead be the subject of a full 45-day notice-and-comment period because of the important implications for California's economy. Air Liquide requests that CARB postpone the adoption of the proposed assistance factors and allow interested parties additional time to analyze CARB's proposals and submit comments. (AIRLIQUIDE)

Response: See response to 45-day comment M-1.1 with respect to timing of notice and comment periods. With respect to the comment regarding postponing assistance factors, ARB staff proposed in the second 15-day amendment package to remove the assistance factors. As indicated in the Second Notice of Public Availability of Modified Text, staff indicated that it would remove the proposed assistance factors for the post-2020 period, and would consider these in a future rulemaking. This change was made in response to stakeholder concerns, such as the one raised by the commenter. As indicated in that Notice, staff is committed to continuing to provide industrial allowance allocation at levels

sufficient to minimize emissions leakage for the post-2020 period to meet the AB 32 requirement to minimize emissions leakage to the extent feasible. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

M-2. Energy Imbalance Market

M-2.1. Multiple Comments:

We urge ARB to participate directly in CAISO's public stakeholder process and in the determination of a solution that reduces uncertainties impacting future EIM participation.
(SCPPA)

Comment:

To this end, we urge CARB to publicly indicate its support for the two-pass approach, and to work closely and transparently with the CAISO to facilitate timely implementation.
(WPTF)

Comment:

Moreover, City Light encourages collaboration between CAISO and CARB throughout the development and implementation of the two-pass solution. This collaboration is crucial for both robust GHG accounting and future market success within the state of California and across the wider West. (SEACITYLIGHT)

Comment:

In our September 19, 2016 comment letter, PGE stressed the need for CARB to work cooperatively with CAISO to find a reasonable solution to EIM GHG accounting and for CARB to implement an interim measure (or bridge solution) while a long-term solution is designed and implemented by CAISO...

PGE requests that CARB clearly indicate its support for CAISO's two-pass model and to work closely and transparently with CAISO to facilitate its timely implementation. Additionally, PGE requests that CARB provide comments and feedback during CAISO's development process to help ensure that CARB will adopt this model and adjust its regulatory program to fit with the technical capabilities of the modified optimization.
(PORTLANDGENELEC)

Comment:

As a long-term approach evolves, PacifiCorp continues to strongly urge better alignment of the ISO and ARB stakeholder processes. In the context of the EIM and a potential regional system operator, fundamental shifts in how electricity imports are treated under MRR and the Cap-and-Trade Program require closer coordination between ARB and the ISO. Important legal and policy questions regarding the appropriate scope and

reach of the Cap-and-Trade Program cannot be separated from technical implementation of any changes as well as Federal Energy Regulatory Commission (“FERC”) policy considerations. Going forward, PacifiCorp requests that ARB and the ISO establish a timeline setting forth each relevant stakeholder process and how the implementation of any changes to the EIM optimization will be designed to align with associated rulemaking activity at ARB. (PACIFICORP)

Comment:

With respect to the development of a longer-term approach, the EIM Entities recommend better alignment between the ISO and ARB stakeholder processes. Any ISO process involving changes to the EIM market optimization will require proposals for input by stakeholders, CAISO Board approval, drafting appropriate tariff changes, Federal Energy Regulatory Commission (FERC) review, updates to Business Practice Manuals, and market software testing and updates. At the same time, ARB must address potentially important policy concerns and regulatory changes associated with how it accounts for electricity imports under the EIM. Changes to the EIM optimization and to ARB regulations must be closely synced so that market participants are able to comply with changing regulations. The EIM Entities recommend that, short of conducting a joint stakeholder process, ARB and the ISO develop a joint timeline showing the timing of technical implementation and FERC approval alongside ARB rulemaking activity. (EIMENTITIES)

Comment:

In December 2016, the ISO issued a straw proposal for stakeholder input that presented a two pass option in the market model to address ARB’s concerns about GHG leakage in the EIM. In PSE’s comments to the ISO’s straw proposal,⁸⁵⁹ PSE voiced reservations about the unquantified negative effects on EIM market efficiencies, customer benefits, and other unintended consequences that could result from implementing a two-pass solution in the EIM market design. We requested that the ISO provide an analysis of potential market outcomes. Similarly, the Department of Market Monitoring submitted comments to the ISO ⁸⁶⁰ which raised specific concerns about modeling simplifications that would introduce errors in a two-pass solution, as well as concerns that these changes “would discourage participation in EIM on both a resource and system level.”⁸⁶¹

Given concerns about the ISO’s straw proposal, we ask that ARB allow sufficient time for and fully support the ISO having a CAISO Stakeholder Initiative process in this matter. This process will take time to develop proposals for input by stakeholders,

⁸⁵⁹ Puget Sound Energy, Comments on Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal, December 7, 2016.

⁸⁶⁰ Department of Market Monitoring, Comments on the Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal, December 15, 2016.

⁸⁶¹ Ibid at p. 3

CAISO Board approval, drafting appropriate tariff changes, Federal Energy Regulatory Commission review, updates to Business Practice Manuals, and market software testing and updates.

PSE is also concerned about changes to the EIM market that could provide a disincentive for EIM participation. The EIM as a whole is providing significant reductions in GHG emissions, in particular due to less curtailment of renewables in the state of California. It would be unfortunate if changes in the EIM model to address ARB's leakage concerns results in increased GHG emissions. (PUGETSNDENRGY)

Comment:

ARB and CAISO have been coordinating public stakeholder meetings and working toward the development of GHG accounting methodologies that would address the "backfill" dispatch issue. These efforts have included ARB possibly adopting an interim solution since CAISO would not have a long-term solution completed by 2017 or 2018. However, LADWP is concerned that the ARB's proposed interim solution conflicts with and undermines CAISO's ongoing stakeholder process to establish a long-term solution. CAISO is expected to release its draft final straw proposal later this month to address its long-term solution and discuss the merits of an interim bridge solution as a result of stakeholder comments submitted last December. LADWP urges ARB to coordinate with CAISO in the rulemaking process and the determination of a solution to reduce uncertainties with respect to the impacts of EIM participation. (LADWP)

Comment:

In the event that implementation of the two-pass solution is not achieved within a reasonable timeframe, it may become both appropriate and necessary to explore additional interim measures that are designed to address the broader range of adverse consequences currently arising from operation of the EIM algorithm. One such additional interim measure, previously discussed in Powerex's comments, would be to explore changes to CARB regulations to require EIM imports serving load in California to be reported as "unspecified energy." Alternatively, CARB and CAISO could work collaboratively to develop other possible additional interim measures in the event that the implementation of the two-pass solution is substantially delayed.

To ensure timely implementation of the two-pass solution in the EIM, Powerex encourages CARB to continue coordinating closely with CAISO regarding implementation timelines and, if it becomes necessary, the design of additional interim measures. (POWEREX)

Comment:

However, ARB and the CAISO must continue to coordinate closely to ensure that the secondary emissions issue is handled in a manner that does not create inappropriate barriers to participation in the EIM given the broader benefits EIM provides to renewable integration and lowering GHG emissions. Defining the problem, quantifying both the

costs and benefits of the proposed solution from an emissions reduction perspective, and aligning the treatment of EIM emissions with other similar transactions are all critical to a reasonable and implementable approach to addressing this issue. (PG&E)

Comment:

At this point, ORA has a number of questions about the proposed 15-day modifications on amendments to the California cap on GHG emissions and market-based compliance mechanisms, and respectfully requests that ARB hold a public workshop or meeting to discuss its proposed bridge solution to energy imbalance market (EIM) imports and address stakeholder comments. Alternatively, ORA recommends that ARB provide written answers to stakeholder comments and questions, and provide another opportunity for comments on the proposed amendments.
(OFFICERATEPAYERADVCT)

Response: ARB staff supports CAISO's efforts to establish a robust accounting framework for greenhouse gas (GHG) emissions in the EIM that also promotes a well-designed potential future regional expansion. ARB staff specifically supports further development of CAISO's two-pass market optimization approach to provide a rigorous accounting framework, which is designed to more accurately reflect GHG emissions from serving California load than the current EIM GHG award methodology. ARB staff looks forward to working together with CAISO to further develop policies and markets that maintain the integrity of AB 32 accounting and ensure a robust electricity grid.

ARB intends to work with CAISO to ensure the final design of the two-pass solution supports accurate GHG accounting under California's regulations. ARB will continue engagement, including joint workshops, on specific details of the two-pass solution of relevance to our regulatory programs as discussed in the response to the 45-day comment D-2.1.

M-3. Interagency Coordination

M-3.1. Comment:

Better coordinate climate pollution and local criteria pollutants programs. (EJAC)

Response: This comment is outside the scope of the current rulemaking. Nonetheless, ARB staff notes that it coordinates with other state agencies, to the extent required by law and as needed to achieve GHG emissions reductions.

M-4. Advisory Councils

Additional Advisory Councils

M-4.1. Comment:

Industrial Advisory Council:

CCPC continues to encourage ARB to establish an “Industrial Advisory Council” (IAC) a representative group of industrial entities be a part of ARB’s process to develop regulations with regard to climate change policies. The IAC will evaluate and provide feedback to ARB staff during the regulatory development process in a formal capacity. (CCPC)

Response: See response to 45-day comment M-1.23.

M-5. Economic Analysis and Additional Research

Additional Review and Comparison Procedures

M-5.1. Comment:

Cap-and-Trade Program Review & Comparison Process:

ARB should direct staff to examine each program under cap-and-trade program against the inventory to determine if adjustments are called for in order to better meet the requirements of our AB 32 goals – that of achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions. (CCPC)

Response: The comment does not request changes to the 15-day language, or to the Cap-and-Trade Regulation rulemaking. As such, no further response is required.

M-6. Adaptive Management

M-6.1. Comment:

Ensure that the Adaptive Management tool is adequate for real-time monitoring and intervention. There must be at least two EJAC members on the Adaptive Management work group. To demonstrate how the tool can help communities, complete an Adaptive Industry Management analysis for Kern County. (EJAC)

Response: The comment appears to refer to a process and a tool that are outside of the scope of the Proposed Amendments. As such, no further response is needed here.

N. CLIMATE PROGRAMS AND SCOPING PLAN

N-1.1. Comment:

Initial Recommendations prepared Aug. 26, 2016; revisions made Dec. 22, 2016.

New text underlined, deleted text in ~~strikeout~~.

Industry
Equity

1	State in the Scoping Plan that it is a priority to reduce emissions in EJ communities, and to ensure no emissions increases happen there. Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities.
2	Use a "loading order" for Industry similar to the one that is used by the California Energy Commission for supplying demand. Always prioritize the approval and use of the most efficient and low-carbon technologies, facilities, and projects over high-polluting ones
3	Address localized impacts of short-lived climate pollutant emissions, such as black carbon from all sources.
4	<p>A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. In addition:</p> <p>Increase enforcement of existing environmental and climate laws, increasing penalties for violations in DACs.</p> <p>Establish a state run "Carbon Investment Fund" allowing the private financial sector to invest in Carbon Futures. Pay dividends through enforcement fines, permit fees and carbon tax receipts.</p> <p>Better coordinate climate pollution and local criteria pollutants programs.</p> <p>Place individual caps on emission sources, rather than using a market-wide cap. Set up a per-facility emissions trigger that will tighten controls when a certain level is reached.</p> <p>Establish a moratorium on refinery permits.</p> <p>Set goal of 50% emissions reduction in Oil and Gas sectors by 2030. Aggressively reduce emissions from these sectors, including fugitive and methane emissions from extraction and production.</p> <p>Put emissions caps on the largest polluters.</p> <p>If Cap-and-Trade continues, do not give out more free allowances.</p> <p>Do not exempt biomass burning activities.</p>
5	The Scoping Plan Economic Analysis must consider carbon tax, command and control regulation, and Cap-and-Dividend or Fee-and-Dividend. Cap-and-Trade must be eliminated. The price of carbon must be increased, with the resulting funds invested in local communities to ensure all benefits from a greenhouse gas free future.

6	Expand the definition of <i>economy</i> to include costs to the public (e.g., U.S. EPA social cost calculator). Conduct an economic analysis that would account for the cost to public health (beyond cancer, respiratory and cardiovascular diseases) and environmental burdens from greenhouse gases. Include the Integrated Transport and Health Impacts Model (ITHIM) in the analysis. Ensure that ARB coordinates with other state agencies in this effort.
Industry	
7	Ensure that the Adaptive Management tool is adequate for real-time monitoring and intervention. There must be at least two EJAC members on the Adaptive Management work group. To demonstrate how the tool can help communities, complete an Adaptive Management analysis for Kern County.
8	To address tension between workers and community members who live in polluted areas, there needs to be access to economic stability and a just transition to the new clean economy. Ensure that workers in Environmental Justice communities whose livelihood is affected from a move to cleaner technologies have access to economic opportunities in that new clean economy and that local businesses continue to employ workers from that community.
9	Do not commit California to continuing Cap-and-Trade through the Clean Power Plan. Since carbon trading cannot be verified, ensure that the Clean Power Plan power purchases are from sustainable, renewable power plants.
10	Eliminate offsets. Actions and investments taken by industry to reduce emissions need to be reinvested in the communities where the emissions have occurred. Any benefits from greenhouse gas reduction measures must affect California first. In addition to California emissions, also consider activities that can reduce pollution coming from across the Mexican border, to reduce emissions in the border region. Do not pursue or include reducing emissions from deforestation and forest degradation (REDD) international offsets in the Scoping Plan.
11	<u>Add AB 197 and SB 350 as a Known Commitments for this sector and remove “Develop a regulatory accounting and implementation methodology for the implementation of carbon capture, and sequestration projects” as a potential new measure.</u>
Coordination	
1112	ARB needs to examine ways to increase its partnerships with and oversight over air districts using its existing authority. Local air districts need to be held accountable to the same standards as ARB. Promises need to be documented and strictly enforceable. If an air district chooses to have stronger standards than ARB, that air district must have the power to enforce those stronger standards without interference from ARB.

1213	<p>Stop “passing the buck” from agency to agency and fix the problems. All agencies need to take responsibility for all pollutants. Coordinate efforts among agencies when necessary, and among local governments and communities. Implement the following measures:</p> <p>Improve community and neighborhood level air pollution monitoring.</p> <p>Add EJ members to all agency boards and committees.</p> <p>Tier pricing for allowances for facilities in EJ communities, making it more expensive to pollute in those communities.</p> <p>Improve communications about air quality between polluters and schools and nearby residents, both for individual accidents and in terms of overall facility emissions. Develop a cooperative, productive discourse.</p> <p>Provide easily accessible and immediate notification to schools and nearby residents in the event of a facility accident; current notification is much too slow. Develop and make accessible tools like the real-time air quality advisory network (RAAN) phone application, so residents can access real-time air quality information at the neighborhood level.</p> <p>Establish better coordination between enforcement agencies. Expand air quality</p>
Industry	
	<p>night enforcement so that all communities have around-the-clock enforcement to address off-hours violations.</p>
14	<p><u>Develop a unified policy similar to (but better constructed than) CAPCOA’s for trading GHG credits among districts. Delete the following sentence: “Where further project design or regional investments are infeasible or not proven to be effective, it may be appropriate</u></p> <p><u>and feasible to mitigate project emissions through purchasing and retiring carbon credits issued by a recognized and reputable accredited carbon registry.” CAPCOA is creating a new carbon market that EJAC has raised concerns about, and it should not be authorized by being in the Scoping Plan.</u></p>
Partnership with Environmental Justice Communities	
1315	<p>Create a thorough air quality monitoring system and deputize the community to participate in that network through databases, apps, and community science. Fund a program to provide communities with the tools and training they need to participate. Identify the pockets not being monitored and also the hot spots. ARB must take a greater responsibility for monitoring. Ensure that all monitoring covers both greenhouse gas pollutants and criteria pollutants, to expand the state’s databases and accurately characterize all communities, so that CalEnviroScreen can more reliably identify areas that qualify for funding. Make monitoring transparent and accessible.</p>

Long-Term Vision	
16	The Industry sector must present a vision of how California is transitioning to a <u>clean energy economy, with clean businesses that will not harm disadvantaged communities. This vision must focus both on the environment and the economy, including the jobs and taxes that will come from a transition to a clean energy economy. For example, analyze the gaps between jobs lost in fossil fuel industry and jobs gained in cleaner industries.</u>
17	Explore scenarios for maintaining local jobs when refineries shut down.

(EJAC)

Response: See response to 45-day comments N-1.4, and responses to 1st 15-day comments L-2.2 and L-2.3.

N-1.2. Comment:

ARB's schedule for developing the 2030 Target Scoping Plan and updating the Cap-and-Trade Regulation coincide with ARB Board adoption of both actions, slated for April 2017. However, much of the data used in the Scoping Plan process would also be used as the basis for developing the post-2020 allowance allocations for the updated Cap-and-Trade Regulation. Unfortunately, this data has not yet been released. As a result, SCPPA believes that ARB should allow a reasonable amount of time after the proposed Scoping Plan is released (e.g., at least 90 days) to further develop amendments to the Cap-and-Trade Regulation in light of the conclusions made in the Scoping Plan process. (SCPPA)

Response: See response to 45-day comment M-1.1.

O. MRR

O-1.1. Comment:

Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities. (EJAC)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.2. Comment:

PROPOSED REVISIONS TO THE MANDATORY REPORTING REGULATIONS

Changes to Meter Data Requirements and the "Lesser of" Analysis. The proposed revisions to the MRR would remove the exclusion from conducting a "lesser of" analysis for grandfathered RPS contracts, dynamically tagged power deliveries, and untagged power deliveries, including EIM imports. *This is a considerable shift from existing policy*

that will have unjustifiably large administrative impacts and, in some cases, prove extremely cost ineffective or infeasible to implement.

As SCPA and its Members participated in lengthy discussions with ARB staff to support our position on this issue years ago, we raise the below points that we shared with ARB staff in January of 2014, which still hold true today:

1. The hourly data comparison would be unduly burdensome -- especially for reporting entities with limited staff resources, and provide little value added.
2. Preparing and aligning hourly generation and schedule data for comparison is a manual process and as such would be prone to human error. Preparing the data is complicated and entails selecting only the contract-related e-tags from the database, aggregating hourly data from multiple e-tags, adjusting for time zone differences and adjusting the generating facility meter data to account for hours when one or more participants do not schedule their full share of the generation from jointly owned facilities. Each case is unique; there is no one-size-fits-all methodology and there currently is no commercially available software application that can automate this process.
3. Hourly meter data may not be available, particularly for “grandfathered” resources, day-ahead, or real-time transactions.
4. A “lesser of” the hourly generation or schedule data requirement will tend to incentivize over-scheduling of certain resources, tying up valuable transmission capacity and increasing costs to California ratepayers.
5. A “lesser of” the hourly generation or schedule data requirement can interfere with contractual terms, as the requirement implies that procuring parties may not get the full resource benefits for which they have contracted.
6. A “lesser of” the hourly generation or schedule data requirement will result in erroneous values for a specified resource that is jointly owned or contracted for due to accounting for fractional shares.
7. A “lesser of” the hourly generation or schedule data requirement is inconsistent with the methodology OATI will use to generate entity-level reports for ARB for independent verification purposes.
8. It does not appear that using “substitute” power in the manner in which ARB staff indicates is consistent with the definition of “substitute” power in the regulations, nor allowed by the Cap-and-Trade Regulation.

We appreciate staff’s statement that it “needs additional information from stakeholders to understand potential data implications,”⁸⁶² and agree that there are several factors

⁸⁶² As provided on page 4 of the [notice](#) of availability and summary of changes for the Mandatory Reporting of Greenhouse Gas Emissions.

that must be considered before making adjustments to the existing provisions. Despite the clarification on the possibility for changes to the proposed language, SCPPA opposes the modifications presented in Section 95111(b)(2)(E) and strongly recommends that ARB engage all interested stakeholders in a discussion on this issue to improve understanding of the concerns shared by stakeholders and the potential downsides of implementing the regulations as proposed. As we note above, 15-day language is not intended to be a vehicle for substantial policy shifts, such as the modifications presented in this section.

Earlier Verification Deadline. As previously raised in written and oral testimony by a significant number of stakeholders, including SCPPA and its Members, the proposed one month shift of the verification deadline from September 1 to August 1 will severely hamper reporting entities ability to comply with the regulation. This does not allow for sufficient time to review data from the (limited pool of) GHG verifiers before submitting it to ARB. While ARB notes that it may revisit the proposed modifications in 2017, SCPPA believes that the change should be considered as early as possible, particularly given the strong opposition from stakeholders across-the-board during the September 19 Air Resources Board Meeting and the subsequent direction from ARB Chairman Mary Nichols, acknowledged by Executive Director Richard Corey, to adopt a compromise position.⁸⁶³ We recommend that staff modify the proposal to a “halfway point” date of an August 15 deadline, if not maintain the currently effective September 1 date. If this issue is deferred to a subsequent workshop, SCPPA will continue to engage in discussions on this issue as they occur via ARB’s public processes, but strongly opposes a switch to August 1st. We are interested in identifying solutions that address ARB staff constraints as well; one such approach that has been shared in the past could be a modification of the deadlines to incorporate phases for submission of verification reports from different entities.

Definitions for “Imported Electricity” and “First Point of Receipt.” As staff surely will be making edits to the regulation for clarity and to correct typographical errors, we note that some clean-up is needed on the definitions for “imported electricity” and “first point of receipt”. SCPPA may offer specific comments on the content once updated language is provided in future iterations of the draft regulation. To avoid regulatory overlap, the language selected to address “imported electricity” and the practical application of this term throughout the regulations and Program implementation should allow for interstate commerce and utility flexibility. (SCPPA)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

⁸⁶³ As described in the transcript, pages 188-189, from the September 22, 2016 Air Resources Board meeting.

<https://www.arb.ca.gov/board/mt/2016/mt092216.pdf>

O-1.3. Comment:

The ISO also supports ARB's proposal to require EIM participating resources to have sufficient metered delivery data to support EIM transfers to serve ISO load...

The ISO supports ARB's proposal to analyze meter data for EIM participating resources that serve ISO load.

In its 15 Day Notices, ARB proposes to apply "a lesser of analysis" based on resource meter delivery data for EIM participating resources that the ISO attributes as supporting an EIM transfer to serve ISO load.⁸⁶⁴ Under this revision, EIM participating resources must have sufficient metered output to support the EIM transfer attributed by the ISO's optimization in any given interval. The ISO supports this change, which is consistent with other requirements that ARB applies to specified sources of emissions. It is appropriate for ARB to validate a resource's output in a given real-time dispatch interval if the ISO has attributed a transfer to that resource. ARB's proposal ensures that a resource is operating at a level to support an electricity import into California. (CAISO)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.4. Comment:

1. Calpine appreciates clarifications ARB has made to the proposed amendments concerning the reporting requirements for operators of geothermal generating facilities

The proposed 15-day changes to Section 95112(e) of the MRR would amend certain proposed reporting requirements for operators of geothermal generating facilities as follows, with the language of the original proposed amendments shown in single-underlined text and the 15-day changes to same shown by double-underlined text:

Operators of geothermal generating facilities must also report whether the source is, (i) a geothermal binary cycle plant or closed loop system, or (ii) a geothermal steam plant or open loop system.

As the operator of the largest number of geothermal generating facilities in California, Calpine appreciates these 15-day changes and concurs in ARB's assessment of them as improving the clarity and readability of the proposed amendments.⁸⁶⁵ (CALPINE)

Response: Thank you for the support for the modification.

⁸⁶⁴ See proposed changes to mandatory reporting regulation at CCR Section 95111 (b)(2)(E).

⁸⁶⁵ See First Notice of Public Availability of Modified Text and Availability of Additional Documents, Public Hearing to Consider Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Dec. 21, 2016, at 6, *available at*: <https://www.arb.ca.gov/regact/2016/ghg2016/ghg15daynotice.pdf>.

O-1.5. Comment:

Powerex is appreciative of CARB's efforts with respect to the definition of "Imported Electricity" in CTR § 95802(a), restoring the "first point of receipt" language that was originally removed in the 45-day rule-making package. While Powerex believes that CARB's initial proposal was helpful, Powerex acknowledges industry concern that the change proposed in the 45-day rule-making process once combined with other portions of the regulation may have added unnecessary confusion. (POWEREX)

Response: Thank you for the support for the modification.

O-1.6. Comment:

Comments on the Proposed Amendments to the Mandatory Reporting Regulation
Delivery Tracking Conditions Required for Specified Electricity Imports

Powerex notes the proposed change made to MRR § 95111(g)(3) in the initial 45-day rulemaking package. Under the current version of this provision there has been some confusion within the industry as to whether or not an electricity importer had the discretion to claim a specified source import when it met the direct delivery requirements and the electricity importer (a) is a GPE, or (b) has a written power contract for the electricity generated. CARB has proposed to replace the word "may" with the word "must", clarifying that an electricity importer does not have the discretion and must claim the electricity as a specified source when the electricity importer meets the prescribed requirements. Powerex appreciates CARB's efforts to clarify this requirement and to address any remaining industry confusion about this provision.

Definitions in the Proposed Amendments to the Mandatory Reporting Regulation

Powerex is appreciative CARB's efforts to modify the 45-day rulemaking's proposed changes in MRR § 95111(a) for the definitions of "First Point of Receipt", "Continuous physical transmission path", "Imported Electricity", and "Generation Source". While Powerex believes that CARB's initial proposal was helpful, Powerex acknowledges industry concern that when combined with other portions of the MRR, the proposed changes to these definitions may have added unnecessary confusion. (POWEREX)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.7. Multiple Comments:

CCEEB is pleased that ARB has indicated a willingness to revisit the proposed change to move up the MRR verification deadline in light of the nearly unanimous stakeholder testimony at the September Board Meeting that this would be difficult for compliance entities to accommodate.

CCEEB's business sector members run complex, large-scale operations that require a great deal of time and expertise to evaluate and verify accurately. CCEEB looks forward to participating in the promised forthcoming workshop to identify a verification deadline that is workable both for compliance entities and ARB staff to ensure that emissions can accurately be accounted for in the state. (CCEEB)

Comment:

The August 1 GHG Verification Deadline for the Mandatory Reporting Regulation is Problematic.

CMUA concurs with comments submitted by many stakeholders, in both written and oral testimony, that the proposed one month shift of the verification deadline from September 1 to August 1 will severely hamper reporting entities' ability to comply with the regulation. This does not allow for sufficient time to review data from GHG verifiers before submitting it to ARB. While ARB notes that it may revisit the proposed modifications in 2017, CMUA believes that the change should be considered as early as possible, particularly given the strong opposition from stakeholders across-the-board during the September 19 Air Resources Board

Meeting and the subsequent direction from ARB Chairman Mary Nichols, acknowledged by Executive Director Richard Corey to adopt a compromise position.⁸⁶⁶ CMUA supports maintaining the currently effective September 1 date. (CALMUNIUTILASSOC)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

O-1.8. Multiple Comments:

Verification Deadlines Proposed Amendments:

Proposed Rule Language: MRR § MRR §95103(f)

Pasadena Water and Power (PWP) does not support the bringing forward of the verification statement deadline to August 1st. Considering the rigorous verification process and demands outlined in the MRR. The shortened verification timeline would subject Facility Reporters and Electric Power Entities (EPE) to the potential for unintended and unforeseen inaccuracies. Based on our past experience, many a time it takes considerable time to address and correct the information.

Moreover, PWP consistently begins its verification process, on or around June 1st of each year, however, we have routinely, arrived at the final stage of the verification process around mid- August. For this reason, if bringing forward the verification

⁸⁶⁶ As described in the transcript, pages 188-189, from the September 22, 2016 Air Resources Board meeting. <https://www.arb.ca.gov/board/mt/2016/mt092216.pdf>.

deadline is necessary, we are recommending a compromise deadline of August 15th instead of August 1st.

Removal of the 'Lesser Of Analysis' Analysis Exclusions:

Proposed Rule Language: MRR §95111(b) (2) (E)

Meter Data Requirement. For verification purposes, electric power entities shall retain meter generation data to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered.

~~This provision. A lesser of analysis is applicable to imports from specified sources including imported electricity under EIM, for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding the following: (1) contract or ownership agreements, known as grandfathered contracts that meet California RPS program requirements in Public Utilities Code Section 399.15(d) or California Code of Regulations, Title 20 Section 3202 (a)(2)(A); (2) dynamically tagged power deliveries; (3) untagged power deliveries, including EIM imports (4) nuclear power; (5) asset controlling supplier power; and (6) imports from hydroelectric facilities for which an entity's share of metered output on an hourly basis is not established by power contract. Accordingly,~~

The proposed rule language under MRR §95111(b) (2) (E) will require EPEs to retain meter generation data and perform a 'lesser of analysis' for imports from zero emission specified sources. We are requesting that CARB reinstate the meter data retention and the 'lesser of analysis' requirements exclusion language to exempt:

- (1) contract or ownership agreements, known as grandfathered contracts that meet California RPS program requirements in Public Utilities Code Section 399.16(d) or California Code of Regulations, Title 20 Section 3202(a) (2) (A);
- (2) Dynamically tagged power deliveries;
- (3) Untagged power deliveries, including EIM imports.

The "lesser of analysis" would be extremely burdensome and in many circumstances, impossible, as long-standing contracts/ownership agreements lack provisions to acquire the hourly meter data. Reporting entities shouldn't receive a non-conformance due to inaccessible data. Furthermore, the significant administrative burden is compounded as a result of the proposed August 1st verification statement deadline. Lastly, PWP appreciates the opportunity to provide comments. Thank you for your consideration. Should you have any questions, please feel free to contact Badia Harrell at (626) 744-7918. (PASADENA)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

VI. SUMMARY OF COMMENTS MADE DURING THE 2ND 15-DAY COMMENT PERIOD AND JULY 27, 2017 BOARD HEARING AND AGENCY RESPONSES

Chapter VI of this FSOR contains all comments submitted during the second 15-day comment period and the July 27, 2017 Board hearing that were directed at the proposed amendments or to the procedures followed by ARB in proposing the amendments, together with ARB's responses. The second 15-day comment period commenced on April 13, 2017, and ended on April 28, 2017.

ARB received 37 letters on the proposed amendments (not including duplicates) during the second 15-day comment period and no written comments at the Board hearing. In addition, 31 commenters gave oral testimony at the July 2017 Board hearing. To facilitate use of this document, comments are categorized into sections, and are grouped by response wherever possible.

Table VI-1 below lists commenters that submitted oral and written comments on the proposed amendments during the second 15-day comment period and at the July 27, 2017 Board hearing, identifies the date and form of their comments, and shows the abbreviation assigned to each.

Note that some comments which follow were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: <https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm>. Transcripts for any verbal testimony presented is available here: <https://www.arb.ca.gov/board/mt/2016/mt092216.pdf>.

A. LIST OF COMMENTERS

Table VI-1

Abbreviation	Commenter
AGCOUNCIL	Rachael O'Brien, Agriculture Council of California Written Testimony: 04/28/2017
AGCOUNCIL2	Rachael O'Brien, Agricultural Council of California Oral Testimony: 07/27/2017
AGPROCESS	Lauren Hajik, California Dairies, Inc., Western Ag Processors and California Cotton Ginners and Growers Association Oral Testimony: 07/27/2017
AIRPRODUCTS	Keith Adams, Air Products and Chemicals, Inc. Written Testimony: 04/28/2017
AMLUNGASSOC	Bonnie Holmes-Gen, American Lung Association Oral Testimony: 07/27/2017

Abbreviation	Commenter
BLUESOURCE	Kevin Townsend, Bluesource Written Testimony: 04/28/2017
BORENSTEIN	Severin Borenstein, University of California Written Testimony: 04/28/2017
BOSWELL	Dennis Tristao, JG Boswell Company Oral Testimony: 07/27/2017
CAISO	Andrew Ulmer, California Independent System Operator Corporation Written Testimony: 04/28/2017
CALCHAMBERCOMMERCE	Amy Mmagu, California Chamber of Commerce Written Testimony: 04/28/2017
CALCHAMBERCOMMERCE2	Amy Mmagu, California Chamber of Commerce Oral Testimony: 07/27/2017
CALMUNIUTILASSOC	Justin Wynne, California Municipal Utilities Association Oral Testimony: 07/27/2017
CCEEB	Gerald D. Secundy, California Council for Environmental and Economic Balance Written Testimony: 04/28/2017
CCEEB	Kendra Daijogo, California Council for Environmental and Economic Balance Oral Testimony: 07/27/2017
CCPC	Shelly Sullivan, Climate Change Policy Coalition Written Testimony: 04/28/2017
CCPC2	Shelly Sullivan, Climate Change Policy Coalition Oral Testimony: 07/27/2017
CIOMA	Samuel Bayless, California Independent Oil Marketers Association Written Testimony: 04/28/2017
CIOMA2	Samuel Bayless, California Independent Oil Marketers Association Oral Testimony: 07/27/2017
CMTA	Michael Shaw, California Manufacturers & Technology Association Written Testimony: 04/28/2017
CMTA2	Michael Shaw, California Manufacturers & Technology Association Oral Testimony: 07/27/2017
CROCKETTCOGEN	Peter Weiner, Paul Hastings LLP on behalf of Crockett Cogeneration Written Testimony: 04/28/2017
CROCKETTCOGEN2	Peter Weiner, Paul Hastings LLP on behalf of Crockett Cogeneration Oral Testimony: 07/27/2017

Abbreviation	Commenter
EDF	Erica Morehouse, Environmental Defense Fund Written Testimony: 04/28/2017
EDF2	Katelyn Sutter, Environmental Defense Fund Oral Testimony: 07/27/2017
EJAC	Environmental Justice Advisory Committee Written Testimony: 04/26/2017
FOODPROCESSORS	John Larrea, California League of Food Processors Written Testimony: 04/28/2017
FOODPROD	John Larrea, California League of Food Producers Oral Testimony: 07/27/2017
JOINTGASUTILS	Fariya Ali, Gas Utility Group Written Testimony: 04/28/2017
JOINTUTILITIES	Adam Smith, Joint Utility Group Written Testimony: 04/28/2017
LADWP	Mark J. Sedlacek, Los Angeles Department of Water and Power Written Testimony: 04/28/2017
LADWP2	Cindy Parsons, LA Department of Water and Power Oral Testimony: 07/27/2017
MINERALSNSTEEL	Doug Houston, Rio Tinto Mineral, US Borax, Gerdau Steel, and the Coalition for Sustainable Cement Manufacturing Oral Testimony: 07/27/2017
MODESTOID	Gary Soiseth, Modesto Irrigation District Written Testimony: 04/28/2017
M-S-R	Martin R. Hopper, M-S-R Public Power Agency Written Testimony: 04/28/2017
NCPA	Susie Berlin, Northern California Power Agency Written Testimony: 04/28/2017
NCPA-M-S-R	Susie Berlin, Northern California Power Agency and M-S-R Public Power Agency Oral Testimony: 07/27/2017
NEXTGEN	Colin Murphy, Nextgen California Oral Testimony: 07/27/2017
PANOCH	Warren MacGillivray, Panoche Energy Center Written Testimony: 04/28/2017
PG&E	Fariya Ali, Gas Utility Group Written Testimony: 04/28/2017
PG&E2	Nathan Bengtsson, Pacific Gas and Electric Oral Testimony: 07/27/2017
PG&E3	Fariya Ali, Pacific Gas and Electric Oral Testimony: 07/27/2017
PORTLANDGENELEC	Elysia Treanor, Portland General Electric Company Written Testimony: 04/28/2017

Abbreviation	Commenter
POSCO	Suzy Hong, USS-POSCO Industries Written Testimony: 04/28/2017
POWEREX	Nicholas van Aelstyn, Beveridge & Diamond PC on behalf of Powerex Written Testimony: 04/28/2017
PROCTER&GAMBLE	Beth Percynski, Procter & Gamble Manufacturing Company Oral Testimony: 07/27/2017
REDDING	Bill Hughes, Redding Electric Utility Oral Testimony: 07/27/2017
ROSEVILLE	David Siao, Roseville Electric Oral Testimony: 07/27/2017
SCPPA	Tanya DeRivi, Southern California Public Power Authority Written Testimony: 04/28/2017
SCPPA2	Tanya DeRivi, Southern California Public Power Authority Oral Testimony: 07/27/2017
SFPUC	James Hendry, San Francisco Public Utilities Commission Written Testimony: 04/28/2017
SHELL	Michael Carr, Shell Oral Testimony: 07/27/2017
SILICONVALLEYPOWER	Steve Hance, Silicon Valley Power, City of Santa Clara Written Testimony: 04/28/2017
SMUD	Timothy Tutt, Sacramento Municipal Utility District Written Testimony: 04/28/2017
SMUD2	Timothy Tutt, Sacramento Municipal Utility District Oral Testimony: 07/27/2017
SOCALLEDISON	Dawn Wilson, Southern California Edison Written Testimony: 04/28/2017
SOCALLEDISON	Adam Smith, Southern California Edison Oral Testimony: 07/27/2017
SOCALGAS	Israel Salas, Southern California Gas Company Oral Testimony: 07/27/2017
SOLARTURBINES	Colleen Klaiber, Solar Turbines Written Testimony: 04/27/2017
SOLARTURBINES2	Craig Anderson, Solar Turbines Oral Testimony: 07/27/2017
SOLVAY	Tim Brown, Solvay Chemicals, Inc. Written Testimony: 04/24/2017
TESORO	Miles Heller, Tesoro Corp. Written Testimony: 04/28/2017
TURLOCKID	Dan B. Severson, Turlock Irrigation District Written Testimony: 04/28/2017
TURLOCKID2	Brian Biering, Turlock Irrigation District Oral Testimony: 07/27/2017

Abbreviation	Commenter
USBORAX	Nicol Gagstetter, Rio Tinto Borates Written Testimony: 04/27/2017
VERNON	Dan Bergmann, Cities of Vernon, Long Beach and Palo Alto Oral Testimony: 07/27/2017
WINDSET	David Wesley, Windset Farms Written Testimony: 04/25/2017
WONDERFUL	Melissa Poole, The Wonderful Company Written Testimony: 04/28/2017
WSPA	Tiffany Roberts, Western States Petroleum Association Oral Testimony: 07/27/2017

B. ALLOWANCE ALLOCATION

B-1. Electrical Distribution Utilities

Allocation for Costs Beyond those of the Cap-and-Trade Program

B-1.1. Multiple Comments:

Section 95892 Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers

These proposed changes are unraveling the main reduction methods applied to EDUs under Cap-and-Trade. The Renewables Portfolio Standard is noted as a primary reason for removing the cap adjustment factors, contradicted by the assumption that “not all RPS eligible electricity has zero GHG emissions associated with it”, introduced in the same sentence. To exempt EDUs from cap adjustment factors removes the incentive to lower the GHG emissions produced when providing electricity. In 2015, coal accounted for only 0.2% of the electricity produced in California and made up less than one and a half percent of California’s electricity at the onset of the Cap-and-Trade program.⁸⁶⁷ To cite the divestiture from coal as the example of EDUs decreasing their dependency on coal is misleading as the industry had not relied on coal for any significant energy production. Additionally, the RPS calculations are being adjusted to reflect the fact that they are not as effective in reducing emissions as previously thought, as well as the roadblocks in adopting renewable energy sources.

When coupled with the proposed Transportation Electrification Activities pursuant to Senate Bill 350, the dollar amount being allocated to power companies in California is sky high. This type of regulatory capture is a clear example of CalEPA choosing winners and losers. CalEPA is exempting utility companies from Cap-and-Trade rules

⁸⁶⁷ California Energy Commission, “Actual and Expected Energy from Coal for California”
http://www.energy.ca.gov/renewables/tracking_progress/documents/current_expected_energy_from_coal.pdf

while providing tax payer funded rebates for electrical vehicles that will charge at power company owned charging stations paid for by the taxpayers.

The title of this section states it is CalEPA's goal to protect consumers from spiking energy costs. Consideration should be given to the costs of Cap-and-Trade that are passed along to consumers at the pump. Consumers, businesses, and tax payers are not being protected from sudden rises in costs as more fees and taxes are applied to the fuels most commonly used to commute to family gatherings and work, and keep industries across California running.

CIOMA urges ARB to continue to apply the cap adjustment factor and not lower the standards for EDUs in order to continue to incentivize the decrease of GHG emissions. (CIOMA)

Comment:

It seems that while all California's diverse businesses are working together in our climate change policy efforts, it appears the language in the new cap-and-trade regulation amendment text is picking winners and losers within our cap-and-trade market system, specifically Section 95892 "Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers." Exempting certain sectors from the cap-and-trade program while continuing to reduce assistance factors for other sectors comes across as arbitrary. Such an action will ultimately undermine the cap-and-trade program. The goal is to reduce our GHG emissions while avoiding price shocks to all consumers for all goods and services, not only the cost of electricity. CCPC along with other stakeholders urge ARB to continue to apply the cap adjustment factor and not lower the standards for EDUs. (CCPC)

Response: The commenters request that the cap adjustment factor be included in calculating EDU 2021-2030 allowance allocation. ARB declines to make this change. The commenter also requests consideration of the GHG costs associated with transportation fuel. This is outside the scope of this rulemaking, and the reasons ARB does not allocate to most non-utilities for ratepayer protection are discussed below.

EDUs are unique among sectors in that they are subject to policies like the RPS Program and Emissions Performance Standard (EPS), which will result in reductions in GHG emissions over time. As the required percentage of RPS-eligible electricity increases over time and coal-fired power contracts are not renewed due to the EPS, decreases in emissions are reflected in reductions in EDU allowance allocations over the 2021–2030 period. Because of the strong pressure from these complementary programs that causes GHG emissions reductions, the cap decline factor is not needed as an incentive to reduce GHG emissions.

Staff reduced the assumed RPS percentage between the first 15-day proposal and the second 15-day proposal. This change was made to reflect firming and shaping (emitting) electricity that is included in the RPS Program, as further discussed in response to 45-day comments B-1.3. The commenter also asserts that removing the cap adjustment factor from EDU allocation calculations removes the incentive to lower GHG emissions from electricity production. ARB disagrees, noting that, by setting fixed allocations for EDUs in the regulation, EDUs are incentivized to lower the GHG emissions from electricity production.

ARB allocates allowances for several purposes: leakage prevention, transition assistance, and ratepayer protection. Allowances allocated to industry are for leakage prevention and transition assistance. After 2020, staff propose that industrial assistance factors will be lower in order to end transition assistance. Allowances allocated to utilities are for ratepayer protection, and utilities are not allowed to use them for non-ratepayer benefit. Because utilities are either subject to California Public Utilities Commission oversight, or are publicly-owned utilities or cooperatives which are subject to local public control and regulation, the State is able ensure that allowance value allocated to utilities is used to benefit ratepayers. ARB does not allocate allowances to other sectors for customer protection because there is no comparable means of ensuring that the allowance value reaches customers. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

Staff are uncertain why one commenter asserts that coal produced less than 0.2% of electricity consumed in California in 2015. The source they cite states that coal use was under 6% in 2015.

Utility-Specific Details of Allocation Calculations

B-1.2. Comment:

Adoption of CARB's latest proposed allocation would drastically reduce the amount of post-2020 allowance revenue that the SFPUC relies on to fund on-going GHG-reducing investments in energy efficiency and renewable energy.

As noted in our previous comments, CARB should set a floor for allocating allowances that recognizes either the "early action" that the SFPUC has taken in reducing its GHG emissions⁸⁶⁸ or by accurately recognizing the "GHG cost burden" that even EDUs such

⁸⁶⁸ For example, the SFPUC proposed a minimum or "floor" allocation of 0.17 lb/MWh based on the GHG profile that California's utilities would need to meet by 2030. This recognizes utilities, such as the SFPUC, that have already met this requirement more than ten years in advance of the compliance date.

as the SFPUC that are 100% renewable still incur. Instead, CARB's latest proposal addresses neither of these concerns.

The requirement to recognize EDUs that have already reduced their GHG emissions is consistent with the Global Warming Solutions Act that requires that "entities that have voluntarily reduced their greenhouse gas emissions...receive appropriate credit for early voluntary reductions."⁸⁶⁹ As noted in our previous comments,⁸⁷⁰ the legislative history accompanying the subsequent passage of Senate Bill (SB)32 (setting the 2030 GHG reduction goal) neither eliminated nor imposed any sunset provisions on "early action" credits after 2020. Instead, as SB32's author, Senator Fran Pavley stated; "SB32 ensures that the policy tools currently being utilized to achieve the existing 2020 greenhouse gas target remain available"⁸⁷¹ beyond 2020. The final legislative analysis accompanying SB32 is equally clear that ARB is required "to consider historic efforts to reduce GHG emissions."⁸⁷²

Instead, CARB's latest allocation proposal continues to ignore early action efforts in its allocation formulas.

Secondly, CARB does not accurately address the "GHG cost burden" that even utilities that are 100% renewable, such as the SFPUC, still incur.

CARB's proposed allocation continues to set a floor of allocating to each EDU a minimum amount of allowances equal to 5% of their forecasted electric demand even if the EDU is 100% renewable. CARB continues to provide no documentation as to how this number is derived. It appears to be based on the need for flexible resources (currently primarily fossil-fueled) to accommodate the ramping up of renewable resources in the morning and ramping-down in the afternoon, as well as fluctuations in output over the course of the day.

As discussed extensively in the SFPUC's comments, a more appropriate range of 15% to 25% should be adopted. This higher value represents the even greater variation between renewable energy during the daytime versus night-time hours as well as seasonal fluctuations in the availability of renewable zero-GHG hydroelectric energy. To address these concerns, the SFPUC proposes that the floor for allocating allowances to utilities that are 100% renewable should be set at a minimum of 20%.

CARB's proposed 5% figure would have the perverse effect of penalizing ultra-clean EDUs by failing to provide sufficient allowances to meet their GHG cost burden. Absent some recognition for the need for utilities with high renewable usage to balance their supply and demand in real-time over the full 24-hour and seasonal cycles, CARB's

⁸⁶⁹ Health & Safety Code 38562(b)(3)

⁸⁷⁰ The SFPUC has previously submitted comments on CARB's previous proposals on November 28, 2016 and January 20, 2017 and incorporates those comments by reference

⁸⁷¹ Senate Environmental Quality Committee Analysis of SB32, p. 8 (April 27, 2015) quoting Senator Fran Pavley, the author of SB32.

⁸⁷² Senate Third Reading Analysis of SB 32 (Pavley) As Amended June 30, 2016.

current proposal could actually disadvantage these utilities relative to other utilities that have fossil-fueled resources that can be flexibly dispatched to meet their demand. Accordingly, CARB should increase the minimum allocation to EDUs to more accurately reflect actual operating requirements. (SFPUC)

Response: See response to first 15-day comment B-1.5.

Allocation for Transportation Electrification

B-1.3. Multiple Comments:

Acknowledgement of Increased Load Due to Transportation Electrification. We further encourage ARB to continue its discussions with the California Energy Commission regarding transportation electrification. ARB previously expressed that it is interested in using after-the-fact data to determine how it could potentially supplement EDU allowance allocations. Instead, we suggest that the collaborative efforts between the ARB and Energy Commission establish a reasonable estimation methodology, which could be used to supplement any gaps in available data needed in ARB's analysis. Ultimately, ARB should work with the Commission to establish a methodology for allocating allowances to address the increased load expected to result from forward-looking transportation electrification efforts. (SCPPA)

Comment:

Electrification: A variety of academic studies and stakeholder reports and comments have indicated the importance of electrification of distributed fossil fuel uses in achieving the long-term GHG-reduction goals of California. SMUD appreciates the continued dialogue with ARB staff regarding adoption and implementation of a methodology that would provide allowances for electrification of the transportation sector and other sectors where electrification can reduce on-site fossil fuel use and hence GHG emissions. CARB must develop an effective regulatory framework for electrification to avoid discouraging this essential pathway to our long-term goals. This framework must recognize that most forms of electrification cannot be economically or practically accompanied by sub-metering programs, and requiring such sub-meters acts as a barrier to implementation. The ARB should recognize the 4-1 emission benefit that comes from transportation electrification and find a method that allows coverage of the electric sector emissions without imposing undue barriers. (SMUD)

Comment:

ARB should continue to remove disincentives for increased electrification in Transportation and other end-uses through the allowance allocation process. In order to meet the State's emission reduction goals in 2030 and 2050, electrification needs to be cost effective and remain a low cost alternative fuel for transportation and other end uses. SCE strongly supports the state's electrification goals and the need for ARB staff to continue its work on a methodology for allocating allowances due to increased electrification. As the state continues toward its long-term climate targets, the emissions

intensity of delivered electricity will continue to fall, making it an ever more attractive option as an end- use fuel. Electricity's role in powering transportation systems, industrial boilers, and building heating are just a few examples of the applications that may increase the emissions attributable to SCE (due to the nature of ARB's current accounting system) but would result in clear emission reductions from a societal perspective. In addition, electrification in transportation and other sectors will yield substantial net reductions in criteria pollutants that will be needed for attaining ambient air quality standards under the federal Clean Air Act. SCE looks forward to discussing options to quantify these cross-sectoral effects and determine a reasonable method for delivering allowances to utilities where they are warranted, in a future rulemaking. (SOCALEDISON)

Comment:

Impacts from Electrification of Other Sectors Should be Addressed as Soon as Possible

It is undisputed that the electricity sector plays a pivotal role in meeting the State's clean energy and climate objectives. Despite the successes already achieved by California's electric utilities, even more will be asked from the electric sector as electrification of the transportation, building, and other segments of the economy expands.

CARB first acknowledged the potential for transportation electrification to impact the electricity sector as early as 2010,⁸⁷³ but now the issue has become even more prominent as the State focuses on 2030. Since then, not only has there been an increased reliance on transportation electrification as a means to meet the statewide reduction effort, but an added emphasis on reducing the use of natural gas in the building sector. All of these portend greater and greater impacts on the electric sector, which should be resolved sooner, rather than later, as the legislature intended.

NCPA agrees that electrification will result in net carbon benefits to all Californians, and should continue to be encouraged. However, the corresponding impacts on the EDUs and their electricity customers must be appropriately recognized. In the original and Second 15-day Changes, staff acknowledged that this issue could be part of a subsequent rulemaking and future program amendments. Most recently, CARB noted that "methods for adjusting EDU allocation based on increased electrification, in particular the transportation sector, may also be considered in a future rulemaking."⁸⁷⁴ Because the impact of electrification on the electric sector is so significant, CARB should prioritize resolution of this issue. The State legislature has mandated that transportation electrification have a greater role in moving the state towards its 2030 and 2050 emission reduction targets,⁸⁷⁵ CARB should address removing barriers to greater

⁸⁷³ 2011 FSOR, p. 570.

⁸⁷⁴ April 13 Notice, p. 13.

⁸⁷⁵ Health & Safety Code § 44258.5(b) The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric

electrification and recognize the associated impacts on EDUs. As such, acknowledging electrification impacts on EDUs' Cap-and-Trade program compliance obligations should be part of a comprehensive joint effort between CARB, California Public Utilities Commission (CPUC), and California Energy Commission (CEC), and should commence immediately. *The Board should direct staff to initiate such a rulemaking as soon as the current rulemaking process is concluded, and that direction should be clearly reflected in this current regulatory process.* (NCPA)

B-1.4. Comment:

CARB must continue to work with stakeholders and its sister agencies to address the impacts of electrification on the EDUs. The most obvious impact from electrification – and the one that was specifically recognized by the Legislature as warranting consideration of additional allowance allocations – comes from transformation in the transportation sector. However, the State's continued move towards greater electrification of the building sector and changes in urban planning that reduce use of natural gas will also increase the demand for electricity. The Notice accompanying the Second 15-Day Changes notes that "methods for adjusting EDU allocation based on increased electrification, in particular the transportation sector, *may* also be considered in a future rulemaking." (Notice at p. 13, emphasis added) Consideration of electrification impacts on the electric sector should not be optional. M-S-R urges the Board to explicitly recognize the importance of this issue and direct that a subsequent rulemaking, to be initiated prior to the end of 2017, address methods for adjusting EDU allowance allocation based on increased electrification. It is imperative that electrification be addressed as soon as possible, and that CARB collaborate closely with the California Energy Commission and California Public Utilities Commission on this issue. (M-S-R)

Response: The commenters request support for allocation to EDUs for transportation electrification. Their comments generally focus on a future rulemaking. Two commenters request that ARB coordinate with the California Energy Commission and one requests that ARB coordinate with CPUC, and another requests that the Board direct staff to initiate a rulemaking for this purpose "as soon as the current rulemaking process is concluded." See the response to 45-day comments B-1.10.

B-1.5. Comment:

We also appreciate recognition in the draft resolution of the important role that transportation electrification will play in meeting the State's clean energy objectives and

utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification.

the impact that that will have on the electrical distribution utilities and look forward to working on a way to ensure that the utilities are properly recognized for the role that they will play in this. (NCPA-M-S-R)

Response: Thank you for the support. To the extent the commenter references future actions indicated in the Board Resolution, those comments are outside the scope of the current rulemaking and no further response is needed.

Allocation and the Renewable Portfolio Standard (RPS) Adjustment

B-1.6. Comment:

While the program includes a recognition that firmed and shaped resources should not be required to surrender allowances, because the State's RPS and Cap-and-Trade programs are not aligned directly, some RPS-eligible resources are assigned a compliance obligation under the Cap-and-Trade program. Reducing the RPS assumptions originally proposed by 5% properly recognizes this disparity, and will ensure that more RPS-eligible resources are excluded from the EDUs' compliance obligation than would otherwise have occurred under the original proposal. Since this proposal does not address all such resources, however, the Board should direct staff to continue to work with stakeholders to develop guidance documents that clarify application of the RPS adjustment to existing contracts to ensure that the Cap-and-Trade program accurately and fairly accounts for all GHG emissions and zero-emissions resources when assigning Cap-and-Trade program compliance obligations. (NCPA)

Response: The commenter appears to appreciate the second 15-day amendments to reduce the RPS assumption by 5%, but requests the Board to direct staff to develop further guidance with respect to existing contracts. Staff is committed to working with stakeholders to ensure they understand the application of regulatory language, including through the development of guidance documents. Staff also notes that guidance does not, and cannot, alter regulatory provisions. Rather, it can provide assistance and further explanation.

Inclusion of Industrial Covered Entity Electricity in Industrial Benchmarks and Removal from EDU Allocation

B-1.7. Comment:

TID Does Not Support the Redistribution of Allowances to Emissions Intensive Trade Exposed Industries.

TID does not support the redistribution of allowances to the covered Industrial customers in our service territory. TID EITE customers benefit from the allowance allocation as constructed from 2013-2020 in that TID has applied allowance value to benefit all of our ratepayers. The increased costs associated with the lower allocation of allowances will be borne by all ratepayers while the fractional benefit due to the application of the assistance factor only marginally benefits the industrial customer. The

reduction in allocations will result in costs that will likely be borne by all of our customers and may not be directly attributed to our EITE customers. Many of these customers that may incur the costs attributable to the redistribution of allowances are located in disadvantaged communities. To avoid placing this additional cost burden on all of TID's customers (particularly our disadvantaged communities), the ARB should not redistribute EITE allowances, or at a minimum, apply the assistance factors in the EITE redistribution such that the reduction in EDU allowances is multiplied by applicable EITE assistance factors. Otherwise, the ARB will effectively be taking allowances away from EDU customers, giving a fraction of those allowances to EITE customers, and then allocating the remaining portion of the allowances to the quarterly auctions. (TURLOCKID)

Response: See response to 45-day comments B-1.15 and B-1.16.

B-1.8. Comment:

Industrial Allowance Allocation Related to On-Site Electricity Use: While very supportive of the overall EDU allocation in the April 13th Amendments, SMUD remains concerned about the proposed reduction of allowances to reflect the carbon costs imbedded in electricity used by covered industrial entities, and eventual provision of some amount of allowances to these customers to cover those embedded carbon costs. As the April 13th Amendments do not include assistance factors for the industrial sector, it is difficult to understand the implications for these customers in terms of changes in net costs under Cap and Trade. SMUD looks forward to understanding the full implications of this proposal and continuing dialogue with stakeholders as assistance factors are included and implementation proceeds. (SMUD)

Response: The commenter expresses generalized concern regarding removing allocation for industrial covered entities' use of electricity from electrical distribution utility (EDU) allocations and adding it to industrial entity allocations.

The regulatory amendments proceed with removing industrial covered entities' use of electricity from EDU allocations and propose to add it to industrial entity allocations, via benchmark recalculation, in a later rulemaking. The specific reasons are discussed further in response to 45-day comment B-1.15.

B-1.9. Comment:

Including Indirect Emissions from Purchased Electricity in EITE Benchmarks

Air Products generally supports the addition of the indirect emissions from purchased electricity in the allowance allocation benchmarks for EITE sectors. Such an approach would more directly mitigate the overall compliance costs and address leakage risks for these sectors. In order for such an approach to be effective and fair:

- Allowanced reallocated to the EITE entities must be on a 1:1 basis – not discounted by the steeper decline imposed upon the Cap Adjustment Factors

and Leakage Assistance Factors applied to the industrial sectors versus the electricity sector allocations.

(AIRPRODUCTS)

Response: See response to 45-day comments B-1.16 and B-1.17.

POU Consignment of Allocation Allowances

B-1.10. Comment:

The consignment of allowances allocated to utilities is a critical element of aligning policy priorities and incentives. Without the consignment of allowances, utilities can use allowances to directly offset the cost of compliance whereas with the consignment and climate credit system the incentive to reduce emissions through a carbon price is preserved, but increases in electricity costs are offset for the majority of California households. For this reason, EDF supports the continued and increased use of consignment for electric utilities, natural gas utilities, and for publicly owned utilities as proposed in this 15-day change package. (EDF)

Response: The commenter expresses support for allowance consignment by electric utilities, natural gas utilities, and for publicly owned utilities. Investor-owned electric utilities are required to consign all their allowances under the current regulation, and this requirement was not changed in the current regulatory amendments. Natural gas utilities are required to consign an increasing percentage of their allowances, with the current amendments adopting a five percent increase through 2030 to reach 100 percent in 2030. Although it is outside of the scope of the current rulemaking, ARB has mentioned it is considering proposing requiring publicly owned utilities to consign allowances in a future rulemaking. ARB agrees with the commenter regarding the value of consignment. See also the response to 45-day comment B-1.27. Thank you for the support.

B-1.11. Multiple Comments:

POU Consignment of Allowances. ARB staff have mentioned, both in public regulatory documents and in stakeholder meetings, that they are considering requiring POUs to consign their allowances to auction and requiring that the auction proceeds be used for specific purposes. The presented justification of this suggests that the change would help align treatment of investor-owned and publicly owned utilities. While we did not see this policy shift in the current set of proposed amendments, we anticipate that it may be re-visited in the future. SCPPA and its Members strongly oppose any modifications to the regulations to require POUs to consign allowances to auction. It is not reasonable to seek this change as a means to “align treatment” of entities that are neither structured nor governed the same way. As such, a requirement for POUs to consign allocated allowances to auction could introduce sizable financial risks and resource needs that

cannot reasonably be addressed, would be administratively inefficient, and would disproportionately affect some POU's more than others.

POUs own and operate their generation facilities, and as such have direct compliance obligations for their assets under the Program. As many SCPPA Members are locked-in to long-term contracts for coal and natural gas resources, the number of allowances necessary to cover their compliance obligation could be substantial. If auctions are undersubscribed or oversubscribed, and POU's were required to consign their allowances, POU's would face substantial financial risks that may impede their ability to meet compliance obligations due to the financial uncertainties that result. POU's do not have shareholder funding to fall back on if there are auction challenges - any additional cost burdens incurred by POU's to manage the Cap & Trade Program, including mitigating the aforementioned financial risks associated with the consignment requirement, may negatively impact POU's' ratepayers while achieving no measurable incremental GHG reduction benefits.

SCPPA provided more detailed discussion on its concern with a potential requirement for POU's to consign allowances in its January 20, 2017, comments on the first 15-day amendments to the Program regulations. (SCPPA)

Comment:

Consignment of Allowances Allocated to Publicly Owned Utilities (POUs)

The "Second Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information" indicates ARB staff is considering future rulemaking to require POU's to consign their allocated allowances like Investor Owned Utilities (IOUs) and return the value to designated ratepayers. Air Products cautions ARB in making this change, as the POU's serving our facilities have been successful in managing the imposed cost of compliance for their self-produced power by retaining and using their allowance allocation. This method has provided the most certain and direct means of cost control; relying upon the process to return the value of allocated allowances consigned to the allowance auctions is slower, less transparent, and less certain means to this same end. While not specifically included as a proposed change in the current Proposed 15-Day Amendments, Air Products is raising this concern with ARB now, since it was discussed in the Notice document. (AIRPRODUCTS)

Comment:

Publicly-Owned Utility Use of Allowances for Compliance

The Public Notice states:

"Staff proposes to pair the aforementioned changes with increased consignment requirements for publicly owned utilities (POUs); these changes would be proposed in a

future rulemaking ... consignment incentivizes GHG emissions reductions by end-users and benefits energy-efficient ratepayers."⁸⁷⁶

As LADWP has stated in its previous comments on the 45-day and first 15-day proposed Cap-and-Trade Regulation amendments, LADWP supports ARB's existing regulatory structure that allows POUs to surrender directly allocated allowances without consigning their allowances to auction. Under the existing Cap-and-Trade Regulation, LADWP has been able to focus on direct GHG reductions without the additional risk to the City of Los Angeles created by being forced to consign allowances through an auction process. Unlike investor owned utilities (IOUs), POUs operate for the exclusive benefit of their communities. POU-owned generation also is generally used only to serve POU customers as part of a vertically integrated electric utility system. Unlike IOUs, POUs do not have subsidiaries that can profit from selling power on the market from their merchant generators. Rather, they have a legal obligation to serve their communities and customers by providing reliable and clean electricity at the most affordable cost. Therefore, the concerns that led to ARB's 2010 decision to require IOUs to consign allowances to auction while not applying to POUs remains valid.⁸⁷⁷ Therefore, LADWP recommends that POUs continue to be able to place its allocated allowances into their compliance accounts. (LADWP)

Comment:

I want to comment on one aspect of the proposed resolution. It's on page 14. There is a proposed resolution to direct staff to continue to work on the POU consignment option. This is basically the mechanism in the Cap-and-Trade Program that allows POUs to either place their freely allocated allowances into consignment or place them into a compliance account. This is critical for the POUs that minimize its administrative costs. And it recognizes that the POUs are vertically integrated, which is an important distinction from the investor-owned utilities in California. This issue was addressed in the rulemaking. It was proposed. And we really don't see a need to continue to work on

⁸⁷⁶ Second Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information (April 14, 2017)

⁸⁷⁷ See ARB, Staff Report: Initial Statement of Reasons at IX-62 (Oct. 28, 2010), <https://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf> [hereafter "2010 ISOR"] ("Rationale for Section 95892(c). Monetization of allowances through auction is intended to ensure that the amount of value given to distribution utilities is transparent to the public, and that this value is used on behalf of electricity ratepayers. This practice will also ensure that freely allocated allowances to a distribution utility will not impact competition in the electricity generation market (where utilities compete with merchant power producers).") *Id.* at II-32 ("By requiring IOUs to put their allowances up for auction, the regulation maintains the current competitiveness of the deregulated California electricity market. In this way, utility owned generation and independent generation have equal access to allowances.") ARB, Final Statement of Reasons at 342 (Oct. 2011), <https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf> [hereafter "2010 FSOR"] ("In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process.").

this issue, so we would ask that you not include that proposed resolution on page 14. (TURLOCKID2)

Comment:

There was one item in the presentation regarding the requirement in the future rulemaking to require all POU's to consign their allocated allowances to auction. We are concerned about that because we are a vertically integrated utility. Having to consign our allowances to auction will incur unnecessary administrative cost, potentially resulting in cash-flow issues; and it will result in rate increases, which will make electricity not quite as affordable, which could adversely impact the electrification efforts. (LADWP2)

Comment:

We'd also like to take this opportunity now to express our concern as ARB turns to implementation of AB 398 to express our concern about the forced consignment of allowances for publicly owned utilities, and look forward to working with ARB and a surely extensive rulemaking process going forward. (SCPPA2)

Comment:

And then I also just wanted to echo the concerns that you heard from SCPPA and TID and L.A. and others about the item in the presentation about requiring consignment of auction for POU's. (CALMUNIUTILASSOC)

Response: The commenters request that POU's continue to not have a consignment requirement, and LADWP requests that POU's not be required to use their auction proceeds for specific purposes. ARB has mentioned both of these proposals in Attachment C to the first 15-Day Notice, although they are outside of the scope of the Proposed Amendments. See also the responses to 45-day comments B-1.20 and B-1.28.

One commenter also mentions the Board Resolution, which directs the Executive Officer to consider requiring all electrical distribution utilities to consign all allocated allowances to auction, and to use auction proceeds for specific purposes to further the goals of AB 32 and SB 32. Several other commenters reference the same issue with respect to the staff presentation at the July 27 Board hearing regarding future consideration of full consignment by POU's. To the extent the commenters reference future actions which are not part of this rulemaking, those comments are outside the scope of the current rulemaking and no further response is needed.

One commenter states that it is not reasonable to seek to align treatment of entities which are not structured or governed similarly. ARB seeks "alignment" in this case in the sense that it seeks for its policies to result in equitable treatment

for ratepayers who are customers of different entities. ARB finds this goal of equitable treatment to be reasonable.

Miscellaneous

B-1.12. Multiple Comments:

The aim of JUG recommendations during this regulatory rulemaking has been to mitigate the bill impacts of AB32/SB32/SB350 programs on their distribution customers. The JUG appreciates staff availability for continued dialogue on the proposed changes to the Cap-and-Trade Program post-2020, and views this iteration of 15-day modifications as a positive resolution for our customers.

JUG Members support the proposed allowance allocation methodology to electric distribution utilities for the protection of ratepayers, as found in these 15-day modifications.

Board approval of the proposed allocation methodology will help ensure that the cost of the State's climate policies will not unduly impact California households, providing critical support to help the State meet its ambitious climate goals at an affordable cost. While the support found in this letter comes from a wide-ranging group of California electric utilities, it is important to note each utility is affected differently by the regulatory changes proposed in the 15-day language. In recognition of this fact, JUG members support the allocation methodology proposed but individual JUG members may reach out to CARB staff to discuss specific issues and technical assumptions.

In helping the state achieve its emission reduction goals, JUG members look forward to working with CARB and other state agencies in a future rulemaking to implement a methodology that would provide allowances for incremental electricity use when that electrification results in cross-sector emission reductions. It is important that CARB develop an effective regulatory framework to avoid discouraging the electrification of transportation and other sectors of the California economy as proposed in the recent Scoping Plan Update. Key components of this allocation framework will include recognition that most forms of electrification cannot economically or practically be accompanied by sub-metering programs, and requiring such sub-meters acts as a barrier to implementation.

The JUG believes that the proposed allowance allocations will serve as a positive step towards the ARB's long-held intent of mitigating the cost burden levied upon electric distribution utility customers by AB 32/SB 32/SB 350 programs (e.g. cap-and-trade, 50% RPS, doubling of energy efficiency, etc.) to help achieve the state's climate goals. JUG members appreciate the continued dialogue with CARB staff and management on these important issues. JUG members urge CARB Board members to approve the electric distribution utility allocation proposal as found in these 15-day modifications.
(JOINTUTILITIES)

Comment:

PG&E supports ARB's proposed modifications to Section 95892 regarding allowance allocation to EDUs for protection of electricity ratepayers. In particular, PG&E supports the removal of the cap adjustment factor from the post-2020 EDU allocation calculations in recognition of the significant GHG reductions expected from EDUs that are already factored into ARB's allocation calculations. In addition, PG&E supports ARB's proposed change to the Renewables Portfolio Standard (RPS) calculation in the EDU allocation spreadsheet to recognize that bucket 2 RPS resources may not be zero-emission resources from a climate policy cost burden perspective. Also, PG&E supports ARB's proposed recognition of Diablo Canyon's 2024 and 2025 license expiration dates in the EDU allocation calculations through prorating assumed nuclear generation in 2025. As modified, the proposed allowance allocations effectively mitigate expected climate policy compliance costs to electricity customers. PG&E looks forward to continuing to work with ARB in a future rulemaking to establish an additional allowance allocation mechanism to address increased load from electrification. (PG&E)

Comment:

The Revised Electrical Distribution Utility Allowance Allocation Proposal Should be Adopted.

The revised EDU allowance allocation proposal set forth in the Second 15-Day Changes provides greater protection to California's residential and commercial electricity ratepayers than the original proposal, and should be adopted by the Board.⁸⁷⁸ Notably, the revised EDU allocation proposal recognizes electricity customers' long-term and ongoing investments in emissions reductions through their utilities, as well as the fact that not all renewable resources used for compliance with the State's renewable portfolio program are considered zero-emitting resources under the Cap-and-Trade Program. Likewise, the changes to the electric load estimates and projections reflected in Attachment 10 to the Second 15-Day Changes more accurately reflect current projections based on revised and updated data than the original proposal.

By removing the cap adjustment factor from the EDU allocation calculation, the revised proposal properly recognizes the significant role that EDUs already play in effecting GHG reductions for the State, as well as the impacts that various mandates and associated program compliance costs will have on the State's electricity customers, including the customers served by NCPA's member agencies. EDUs have made significant expenditures in emissions reductions through increasing renewable energy

⁸⁷⁸ As previously noted, NCPA fully supports CARB's recommendation to continue to provide EDUs with allowances for the benefit of their electricity customers and use of an allowance allocation methodology that would assign allowances for the entire 2021 to 2030 period, reflecting the timeframe covered by the current GHG Allowance budget.

purchases, expanded energy efficiency, and other clean energy investments.⁸⁷⁹ Many of the mandates and programs that achieve reductions in GHG emissions have resulted in significant expenditures on the part of the EDUs, which are reflected in current electricity rates. These GHG reductions are also reflected in the current and projected future emissions upon which the allowance allocation is based. Removing the cap adjustment factor for EDUs correctly recognizes the EDUs' proactive and ongoing reduction activities, and avoids imposing a duplicative reduction mandate on the utilities. Doing so also avoids burdening electric ratepayers with paying for emission reductions twice. Since the number of allowances allocated to many EDUs for the post-2020 program period is significantly less than the 2013-2020 allocation, removing the cap adjustment factor also helps decrease the "2021 cliff" and the associated detrimental impacts on electricity customers.⁸⁸⁰

The revised EDU allowance allocation reflected in the Second 15-Day Changes recognizes that all renewable resources that are used for compliance with the RPS mandate are not counted as zero-emission resources under the Cap-and-Trade program. (NCPA)

Comment:

Support for Staff's Proposed Allowance Allocation Methodology for Electric Distribution Utilities (EDUs)

SCPPA and its Members support staff's modified allowance allocation methodology for EDUs, as outlined in the second 15-day regulatory package. The recent revisions acknowledge that EDUs are subject to a number of existing and planned policy mandates that put utilities on a glide path to continuing our sector's significant contributions to the state's greenhouse gas reductions. A number of policies and events with substantial impacts on our Members' procurement and operations have become effective or occurred in recent years. We anticipate that an increased focus on prescriptive procurement requirements for utilities may continue, particularly given the number of bills that exemplify this trend in the current legislative session. The majority of these policies are intended to drive further GHG emissions reductions (e.g. implementation of an increased Renewables Portfolio Standard). ARB staff's proposal appropriately adjusts the EDUs allowance allocations to better reflect the actual cost impacts that our customers may feel due to the tremendous policy efforts that we are undertaking as a state. (SCPPA)

⁸⁷⁹ It is worth noting that investments of this type were actively encouraged by CARB. The 2011 Final Statement of Reasons repeatedly notes that the allowance allocations to EDUs "will encourage continued investments in efficiency and clean energy in the future." See, for example, p. 229, 230, 233, 1071.

⁸⁸⁰ Due to the differences in the allocation methodology used in 2013 versus the way the allocations are calculated for 2021 to 2030, some EDUs will have a significant decrease in allocated allowances between 2020 and 2021. This difference, coupled with the steeper rate of decline that would result from application of the cap adjustment factor, would result in a "2021 cliff."

Comment:**LADWP Supports ARB's Proposed Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers**

LADWP supports ARB's proposed allocation to Electric Distribution Utilities (EDUs) as described in the second 15-Day Amendment text and appreciates ARB staff's time in working with the LADWP and other EDUs to develop an allowance allocation methodology that protects electricity ratepayers and recognizes the investments and efforts EDUs such as LADWP are making to significantly reduce their GHG emissions. Over the next decade, LADWP intends to replace all existing coal resources with nonor low-emitting replacement generation, meet the 50 percent renewable portfolio standard (RPS) by 2030, modernize its Los Angeles basin power plants, continue its efforts to improve end-use energy efficiency, invest in electric transportation infrastructure to assist in reducing mobile source emissions, and develop increased capacity for energy storage.

LADWP supports ARB's decision to allocate allowances to each EDU based on the consumer cost burden, as determined by expected electric load to be served by each EDU and the electric resource mix that each EDU expects to rely on to serve its future load. The allowance allocation methodology included in the proposed second 15-day amendments better reflects the consumer cost burden goal by eliminating the cap adjustment factor. Specifically, ARB's proposal to remove the cap adjustment factor in the allocation methodology correctly recognizes that EDUs are already required to reduce their GHG emissions by substantial amounts to comply with RPS, SB 1368 and other regulatory requirements. (LADWP)

Comment:**Utility Allocation**

EDF believes that the proposed adjustment to post-2020 utility allocation is an appropriate balancing of policy objectives although other options would also have been acceptable to us. Not imposing the cap adjustment factor on utilities means more allowance value will go to electricity rate-payers verses being invested in greenhouse gas reducing projects through the Greenhouse Gas Reduction Fund. As a report by the UCLA Luskin Center⁸⁸¹ found, this benefit to rate payers is important especially for low-income Californians who may actually see a net economic benefit from climate credits they receive because of the cap-and-trade program. (EDF)

Comment:

SMUD appreciates the continued administrative allocation of allowances to electric distribution utilities (EDUs) on behalf of their ratepayers at the levels contained in the

⁸⁸¹ Available at <http://innovation.luskin.ucla.edu/sites/default/files/FINAL%20CAP%20AND%20TRADE%20REPORT.pdf>

April 13th Amendments. One of SMUD's primary goals when commenting on the development of the post-2020 Cap and Trade program has been to mitigate the potential costs to our customer-owners as the program is extended. Previous proposals on allowance allocation represented a significant risk to our customers – on the order of \$100-\$400 million dollars. The changes proposed to EDU allowance allocations in the April 13th Amendments represent a dramatic reduction in this risk, and provide a reasonable hedge against these potential ratepayer impacts.

In short, SMUD fully supports the proposed EDU allocations in the April 13th Amendments. SMUD appreciates the continued dialogue with ARB staff and management that has led to this reasonable structure. Air Board approval of this allocation structure will help to ensure that climate policy will be cost-effective for California ratepayers. In particular, these impacts would have been hardest to absorb for SMUD's lower income customers and those living in disadvantaged communities. (SMUD)

Comment:

SCE supports the proposed allowance allocation methodology to electric distribution utilities for the protection of customers, as found in these 15-day modifications.⁸⁸² Board approval of the proposed allocation methodology will help ensure that the cost of the State's climate policies will not unduly impact California households, and will further enable EDUs to continue investing in cleaner electricity resources, providing critical support to help the State meet its ambitious climate goals at an affordable cost. This proposed methodology recognizes the current and ongoing policy drivers achieving emission reductions in the electric sector in a way that improves upon previous proposals. (SCE)

Comment:

MID supports the electric distribution utility (EDU) allowance allocation methodology developed by ARB staff and urges the Board to approve the proposed allocation schedule. The changes made by ARB staff to the allowance allocation methodology in the second 15-day changes recognize the fact that EDUs comply with additional measures and mandates that guide the electric sector towards reduced emissions and require compliance costs outside of the Cap-and-Trade program. By reducing the Cap-and-Trade cost burden on electric service customers as EDUs continue to invest in renewable energy, the state will be better positioned to affordably meet its emissions reduction goals. (MODESTOID)

Comment:

The revised proposal for allocation of allowances to the EDUs for the protection of their ratepayers better reflects the EDU cost burden and should be adopted. The revised proposal for EDU allowance allocation correctly recognizes the unique role of the electric

⁸⁸² Section 95892

sector and electric utilities in meeting the State's climate objectives. In light of the existing measures and mandates that result in GHG reductions from EDUs outside of the Cap-and-Trade Program, it is appropriate that the EDUs not also be subject to an additional restriction by applying the cap adjustment factor to the allowance allocation. Similarly, the revised basis for determining zero- GHG resources based on an EDU's renewable portfolio standard (RPS) compliance obligation recognizes the imperfect alignment between the Cap-and-Trade program and the RPS program. M-S-R appreciates staff's recognition of these important factors and urges the Board to adopt the revised EDU allocation proposal set forth in the Second 15-Day Changes. (M-S-R)

Response: The commenters support the regulatory amendments for 2021-2030 EDU allocations. Thank you for the support.

B-1.13. Comment:

We support the comments by the joint utilities group and the M-S-R Public Power Agency. The Cap-and-Trade and RPS programs have reduced emissions statewide but also in Redding. With the most available data available to us through June, we are on course to reduce our emissions by percent next year.

We are in support of it with the allocation of allowances. If there were no allocation of allowances, with the life and scenario of alloca -- of allowance prices post 2020, it would cost each of our customers \$1400. And that would also be a 4.8 percent rate increase.

Redding is generally a low-income community, and many are struggling with the cost of utilities. And so we urge you to retain these amendments as is and support our ratepayers. (REDDING)

Comment:

We do appreciate the continued allocation of allowances to electric utilities for ratepayer protection and in recognition of the significant investments that we're making to reduce emissions.

This allocation enables LADWP to invest in renewable energy, energy efficiency projects that will assist in meeting the State's environmental goals, while minimizing cost to our customers and protecting our low-income and disadvantaged communities. Over the next decade we will be making significant additional investments to reduce emissions and modernize our fleet of generating resources.

In addition, we are actively involved in electrification. And this allocation will help to keep the cost of electricity affordable to assist with electrification. Without electrification, the State may not achieve those long-term goals. So electrification we feel is very important. And so keeping the cost of electricity affordable as a low carbon alternative to conventional fuels we feel is very important. (LADWP2)

Comment:

Approval of this regulatory package will also protect electricity customers from dramatic bill increases by continuing existing ratepayer cost protections in the Cap-and-Trade Program. The direct allocation to electric utilities for the benefit of our customers has been an integral part of the program since its inception and is now more important than ever.

It's important to note that this consumer protection has benefited all ratepayers. Academic review from the UCLA's Luskin Center has shown that the existing California climate credit, which the IOUs hand out as a direct on-bill rebate to our customers, has been an effective measure to protect low-income ratepayers, as we transition to a clean energy economy.

And that transition to a clean energy economy is only going to increase in the years ahead. As many of you know, electrification of transportation, buildings, industrial processes is one of the State's key long-term strategies to achieve our climate goals. And allocating electric utilities the allowances necessary to cover our customers' cost burden doesn't just help shield our customers from significant bill impacts; it also helps keep electricity as price competitive as possible. This is increasingly important as we rely on a cleaner electricity mix to fuel more end uses in the California economy.
(SOCALEDISON)

Comment:

A significant and very critical element of the Cap-and-Trade Program and the amendments you are asked to approve today is the allocation of allowances to electrical distribution utilities. This allocation provides direct protections to utility customers of NCPA's and MSR's publicly owned utility members. And the allowance value they receive not only protects the customers from excessive cost increases, rated increases, but it provides revenues for investments directly in the communities that they serve for GHG reducing and clean energy programs. These direct benefits to the customers are an instrumental part of the success of the Cap-and-Trade Program, we believe...

And we also appreciate your consideration of the amendments that would allocate allowances directly to the utilities, and we ask that you approve them. (NCPA-M-S-R)

Response: The commenters support allocation to EDUs, as included in the regulatory amendments. Thank you for the support.

B-1.14. Comment:

TID Supports the Removal of the Cap-Adjustment Factor From the Electric Distribution Utilities Post-2020 Cap-and-Trade Allowance Allocations.

The April 13, 2017 Amendments implicitly recognize the fact that the electricity sector is already subject to emission reductions by virtue of other state policies, such as the RPS. TID supports the removal of the Cap Adjustment Factor ("CAF") for the electricity

sector. With the economy wide “Cap” already set at a significant decline (from 334 mmtCO₂e in 2020 to 193 mmtCO₂e in 2030), the application of the CAF would have increased compliance costs on retail ratepayers. By removing the CAF, the proposed Amendments further the fundamental ratepayer protection rationale for free allocation to EDUs. Moreover, for EDUs like TID that primarily serve disadvantaged communities, the removal of the CAF will help minimize compliance costs for these customers in furtherance of the goals in AB 197. (TURLOCKID)

Response: The commenter supports the removal of the cap adjustment factor from EDU allocation calculations. Thank you for the support.

B-1.15. Comment:

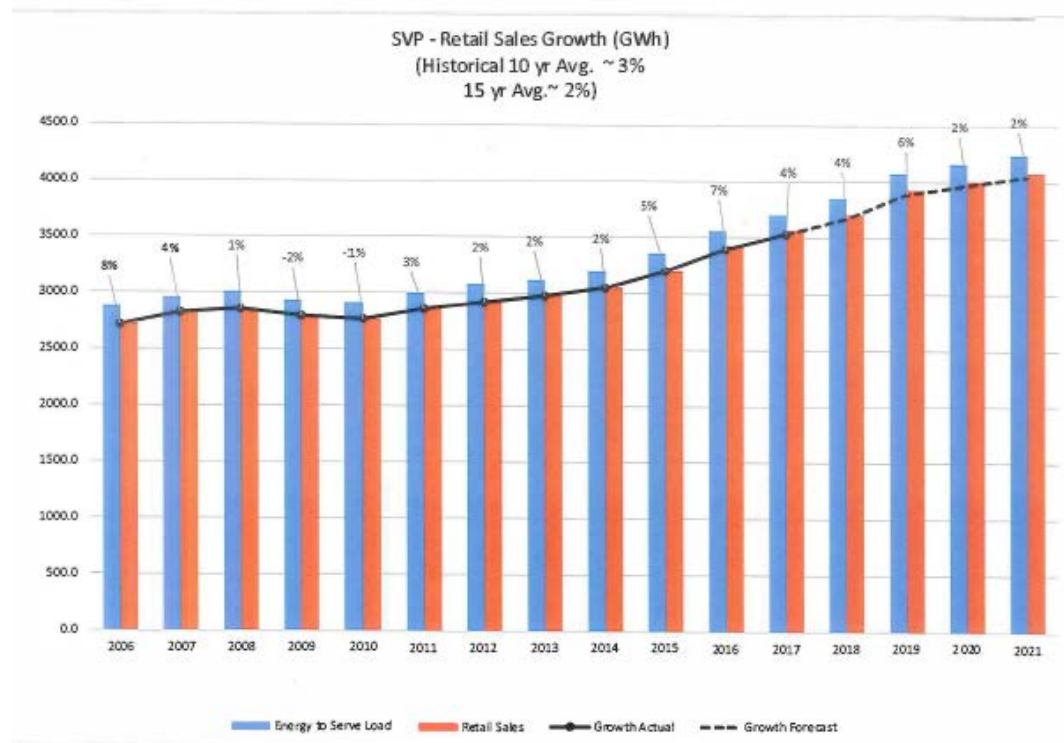
The revised EDU allowance allocation proposal recognizes the greenhouse gas (GHG) emission reductions that EDUs accomplish through a range of State climate policies and related mandates, in addition to meeting the emissions cap mandated by the Cap-and-Trade Program.

By providing the EDUs with allowances to cover their program compliance costs, the revised proposal better protects the State's electricity ratepayers from unreasonable rate increases associated with compliance costs. The revised allocation proposal also modifies the load forecast assumptions for 2021 for SVP based on verified growth in the City's load that exceeded the forecasted projections used in the original allocation proposal. As more fully explained in the City's January 20 comments,⁸⁸³ SVP has experienced unprecedented load growth in the last few years, due almost exclusively to "data centers" locating in Santa Clara. SVP experienced 5% load growth from 2014 to 2015, and an additional 7% growth from 2015 to 2016. Using the currently available data and continuing even a modest growth rate out to 2030, SVP's load growth projections greatly differ from the numbers used in the original CARB model. This load growth is evidenced in Attachment 15 to the second 15-Day Changes,⁸⁸⁴ the City of Santa Clara's 2016 Audited Utility Fact Sheet, and is the reason why the original proposal for allocation of allowances significantly underestimated SVP's cost burden and substantially under-allocated allowances to the City for the benefit of its ratepayers. Using the City's updated load forecast demonstrated in Attachment 15, the revised EDU allowance allocation proposal more accurately reflects the cost burden to SVP and better protects its electricity ratepayers through the allocation of additional allowance to accommodate the load growth. For these reasons, the City encourages the Board to adopt the revised EDU allowance allocation proposal, including the updated load projections for SVP, as set forth in the April 13, Second 15-day changes and listed in Attachment 10 to those further proposed modifications.

⁸⁸³ City of Santa Clara, Silicon Valley Power Comments on Cap-and-Trade Program Proposed Amendments, January 20, 2017.

⁸⁸⁴ City of Santa Clara, Silicon Valley Power; Utility Fact Sheet—January 2016 to December 2016.

[The commenter attached an unaudited fact sheet for Silicon Valley Power stating that their 2016 load was 3,425,801,811 and a chart which is shown below:]



(SILICONVALLEYPower)

Response: The commenter supports the regulatory amendments' calculation of Silicon Valley Power's 2021-2030 allocations. Thank you for the support.

B-2. Natural Gas Suppliers

B-2.1. Comment:

On page 13, the proposed resolution directing the executive officer to work with natural gas utilities recognizes the importance of ratepayer protections, which we believe is being met with the existing utility allowance allocations and other banking rules as well as other cost containment measures. We look forward to and welcome the opportunity to work with ARB staff to further ensure that we are given the tools to ensure that we protect community health and our environment and while keeping cost to utility customers just and reasonable. (SOCALGAS)

Response: The commenter states that they believe existing gas utility allocation, banking rules and cost containment measures are meeting ratepayer protection needs. Thank you for the support.

B-2.2. Multiple Comments:

We - Vernon, Long Beach, and Palo Alto - have three things in common. We are the covered public gas utilities in California. And in this process we've been working with a larger investor-owned utilities. But because of the importance of the program, we have gotten very involved.

I want to say that we support the resolution and that the continued opportunity to continue to work with staff toward a program that is equitable to rate payers, specifically that critical balance between the cost of emissions and the cost that we have to implement assigned to our customers for the program. We especially appreciate the consideration for the continuation of free allowances as the program goes forward.

For Vernon especially, if you people have heard of Vernon -- of Palo Alto and Long Beach, but Vernon's a little bit unique. Vernon is five square miles of industry just south of downtown L.A. Historically it's one of those cities of industry. But this city of industry is Vernon. It's an industrial base with some very gas-intensive customers. So the design of the program is critically important in that we want these customers to operate more efficiently and benefit from a program rather than leave the State.

In Vernon we already have a rebate program implemented because publicly-owned utilities are regulated by city councils, and we've been able to move fairly quickly. The program's working. Customers are understanding the program and already benefiting from rebates that we have in place. It's great to have the gradual transition that's designed into the program so that they can learn and adapt over the years ahead.
(VERNON)

Comment:

My name is Fariya Ali and I am speaking on behalf of PG&E on the natural gas supplier section of the amendments. As my colleague Nathan already stated - however I can't pull off saying y'all, so I'm not going to try -- but I will reiterate that PG&E supports the cap-and-trade amendments before you today. And we believe that this program is critical to achieving the deep cuts that are needed by 2030.

Specifically in these amendments, PG&E supports the continuation of the grant of allowances to natural gas suppliers for customer protection and transition assistance.

PG&E supports the adoption of Resolution 1721, and appreciates the acknowledgement from staff of the need to protect customers from rising GHG costs, while gradually introducing a price signal across all portions of California's economy, and also acknowledging the role of a decarbonized natural gas system in meeting our climate goals. We look forward to continuing to work with all stakeholders to improve upon the foundation laid in these amendments in the forthcoming months. (PG&E3)

Response: Thank you for the support.

B-2.3. Multiple Comments:

PG&E supports allocating free allowances to protect ratepayers from rising GHG costs and to offer transition assistance that gradually introduces a price signal across all portions of California's economy in the coming years. To this end, PG&E appreciates ARB's April changes to maintain the current rate of consignment for natural gas suppliers at a five percent annual increase reaching 100% in 2030.

However, the proposed amendments will effectively double the cap adjustment factor (CAF) for the natural gas sector from approximately two to four percent per year. PG&E maintains that a lower post-2020 CAF for the sector is appropriate for a number of reasons.

For one, natural gas suppliers currently have limited near-term opportunities to lower compliance costs through the procurement of renewable or low carbon natural gas (RNG). PG&E supports the goal of transitioning the natural gas sector to a more sustainable future through increased deliveries of RNG, and providing natural gas customers a lower cap adjustment factor will allow natural gas suppliers time to ramp up development and procurement opportunities in the nascent RNG market. While the state's natural gas suppliers are working to increase deliveries of RNG and the dairy pilot projects required by Senate Bill 1383 will help spur project development, supply is still too uncertain to replace conventional natural gas at any significant scale. In contrast to the broad availability of renewable electricity, the potential supply of RNG is still limited, and is relatively expensive as a GHG abatement opportunity. The cost of developing the RNG market will be reflected in retail gas rates, and a steep increase in the cap adjustment factor will exacerbate those rate increases.

Additionally, ARB's reasoning for increasing the CAF to four percent per year relies on the hypothesis that customers facing direct carbon prices will be incented to reduce consumption or utilize alternatives to natural gas. PG&E believes that increasing rates and net costs 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 highly responsive to retail price signals. Direct incentives for promoting efficiency or conservation may work more effectively.

For these reasons, PG&E recommends ARB continue the dialogue with natural gas suppliers to provide a post-2020 allocation that strikes the appropriate balance between incenting GHG reduction and protecting natural gas customers. (PG&E)

Comment:

The proposed modifications continue the current 5% annual increase in the consignment requirement for natural gas suppliers to reach full consignment in 2030, and remove the previous proposal to begin full consignment in 2021. This change acknowledges the concerns related to accelerated consignment raised by the GUG in its previous comments to the ARB on September 19, 2016, November 4, 2016 and

January 17, 2017 which are incorporated herein by reference. The GUG appreciates ARB's inclusion of a gradual transition to full consignment, which will protect natural gas customers from a sudden increase in rates in 2021. However, the GUG remains concerned with the long term rate impacts from an accelerated decline in the allowance allocation to the natural gas sector as discussed in more detail below.

The GUG Maintains that Differential Treatment of Natural Gas for the Post-2020 Adjustment Factor to Allowance Allocation is Appropriate

The Cap-and-Trade Amendments continue to decrease the amount of allowances for natural gas at a rate that is approximately double the current rate of decrease. As stated in previous comments, the GUG believes that a lower rate of reduction for natural gas is appropriate given the differences of the natural gas sector compared to others. These reasons are summarized as follows:

- *Different opportunities for efficiencies:* The opportunities for natural gas customers to reduce natural gas usage are considerably fewer in the near term given that the efficiency options available to them remain limited.
- *Different renewables markets:* The GUG supports the growth of renewable gas (RG) and believes it has an important role to play in achieving the state's emissions reductions goals, but the market is still nascent. While legislation such as Senate Bill 1383 will help to push the industry forward, the fact that the program is still at the stage of fostering pilot projects demonstrates the long path that still lies ahead. A less aggressive decline in allowance allocation will allow natural gas suppliers time to ramp up development and procurement opportunities. The cost of that market development will be reflected in retail gas rates, and a steeper decline in allowance allocation would exacerbate those rate increases.
- *Different elasticities of demand:* Historically, natural gas demand from residential, small commercial and small industrial customers has not been highly responsive to retail price signals.

The GUG Requests Ongoing Consideration of Alternative Proposals

While the GUG applauds the ARB's move to maintain a gradual transition to full consignment, this addresses only a short-term concern. Over the course of the ten years from 2021 to 2030, the cumulative impact of a doubled decline in allowance allocation (~4%) will lead to higher overall net GHG program costs for natural gas customers as fewer allowances are available to offset cost increases. For the reasons highlighted above, it will be difficult for natural gas customers to reduce or use alternatives as an option to minimize GHG costs. Therefore, a longer adjustment period for natural gas is critically important.

The GUG proposes maintaining the current rate of decline in allowance allocation of approximately 2% through 2030. The GUG's proposal would facilitate the introduction of renewable gas by keeping the overall net costs of achieving SB 32 goals lower.

In addition to this approach, the GUG will continue to develop other options that strike a balance between the ARB's goals to incentivize GHG reductions and spur the development of renewable gas, and protect natural gas customers from excessive costs during the transition to a lower GHG economy. We urge ARB to continue this dialogue with the GUG so that we can come to an optimal solution in the next opportunity for regulatory action prior to 2020. (JOINTGASUTILS)

Response: The commenters request that natural gas suppliers be subject to a lower cap adjustment factor than other sectors during the 2021–2030 period. Please refer to the response to 45-day comments B-2.5 and response to 1st 15-day comment B-2.2, which responds to this comment.

B-3. Legacy Contracts

B-3.1. Comment:

PEC is still a Legacy Contract Holder and respectfully asks ARB to address this issue in an expeditious manner. Facilitating a solution is even more important to ensure California's Cap and Trade Program continues to be consistent with the principles of AB 32. It would also recognize that PEC has acted in good faith as a Legacy Contract holder and within the bounds of the Regulation for the past five years

As you know, PEC is a large natural gas peaking plant with a tolling agreement ("PPA") for the exclusive sale of electric power to Pacific Gas & Electric Company ("PG&E"). The PPA was executed, prior to AB 32 in March 2006 which, in part, qualified PEC as a "Legacy Contract" PPA. Since the beginning of the Program, PEC has requested Transition Assistance from ARB. Each year, ARB has granted PEC's request. Nothing has changed to alter ARB's decision-making in connection with PEC's contract status. Therefore, so long as the contract between PG&E and PEC remains unamended, and PEC continues to satisfy the other criteria previously established by ARB for transition relief, ARB should continue to work on a reasonable solution to this important issue.

At PG&E's sole discretion, the price of carbon was removed from PEC's variable energy dispatch price effective January 1, 2014 which has resulted in PEC's actual dispatch (and associated emissions) being much higher than its anticipated dispatch. Without a price of carbon included in PEC's dispatch price, the facility has operated far more, resulting in:

- (1) increasing local air pollution,
- (2) the complete undermining of the regulatory "price signal" intended to be sent to consumers,
- (3) increasing use of scarce water resources,

- (4) increasing costs for PG&E ratepayers, and
- (5) increasing costs of operation.

Such a situation, left unchecked should undoubtedly trigger an Adaptive Management Review.

Another key element of the historic Legacy Contract policy is that counterparties work to resolve the Pre-AB 32 contractual issues. Since the Cap and Trade Regulation's original adoption, PEC has continually sought in good faith to secure a just and reasonable contract amendment with its counterparty *on terms consistent with other Public Utilities Commission approved Legacy Contract settlements*. PEC has repeatedly approached its counterparty to negotiate a resolution directly and through the offices of the Public Utilities Commission, ARB, private channels, and others, all to no avail. Over the past five years, PEC has only sought an equitable and reasonable renegotiation of the terms of the Legacy Contract, but this has not been achieved due to our counterparty's complete lack of good-faith effort. Additionally, the proposed cessation of Legacy Contract relief would harm PEC and its bondholders, including public pension funds, and all other stakeholders (including PG&E ratepayers), except for PG&E who would continue to run PEC's facility without AB 32 compliance costs. The most recent 15-day package proposes to continue this inequity.

A solution is still needed. There are several options available to ARB. One such solution was outlined in PEC's comments on the 1st 15-day amendment package⁸⁸⁵, but others exist and PEC will continue to pursue an equitable resolution to this multi-year issue.

Eliminating the prior regulatory relief, as currently proposed, retains the status quo—providing zero incentive for PG&E to address this situation. Meanwhile the environment, the citizens of the San Joaquin Valley (a state-designated disadvantaged community), PG&E's ratepayers, and PEC's bondholders are negatively affected. There are no winners under the current situation, only losers.

To avoid these impacts, and for the reasons described in this letter, ARB should continue to work toward a solution as soon as possible to address the problem and to ensure the fundamental policies of the program are upheld without undue burden on Legacy Contract holders.

PEC urges ARB to act now. We have actively engaged at all levels of the ARB process and sought in good faith to find a solution for the better part of five years, now it is up to ARB to step in and fix this problem before additional local pollution is emitted as a direct result of its implementation. (PANOCHE)

⁸⁸⁵ <https://www.arb.ca.gov/lists/com-attach/166-capandtrade16-BnYCYQdIWFBZAdo.pdf>

Response: The commenter requests that ARB address its issue either by making the changes requested in its first 15-day comment letter or otherwise. See response to first 15-day comment B-3.1.

B-3.2. Comment:

The Second Notice of Public Availability of Modified Text and accompanying Proposed Amendments reflect that Staff has elected to not consider Crockett's comments and request for relief in the context of the 2016 rulemaking process. Staff did discuss in the Notice, however, that it intends to initiate a new rulemaking process once the 2016 proceeding is completed to address assistance factors and industrial allocation for post-2020 compliance periods, necessitated by the deletion of Table 8-3 and provisions relating to post-2020 industrial allocation in response to stakeholder comments.⁸⁸⁶ These deletions also had the technical effect of eliminating post-2020 allocation to legacy contract generators with an industrial counterparty. As a result, Staff indicated that it "intends to propose, in a future regulation, changes that would reinstitute post-2020 legacy contract allocation at the same time that post-2020 industrial assistance factors are proposed."⁸⁸⁷

While not clear from the discussion in the Second 15-Day Notice, it is Crockett's strong desire that the future rulemaking and regulation described by Staff will address transition assistance for legacy contract generators without an industrial counterparty, and extend assistance for the life of the contract. As noted previously, assistance is slated to end with the second compliance period, and there is only one [remaining] entity – Crockett – whose contract extends beyond 2017.⁸⁸⁸ Crockett remains as equitably entitled to transition assistance as all other legacy contract generators without industrial counterparties, all of whom were provided assistance for the lives of their contracts. Crockett provides steam to C&H Sugar, which in turn uses the steam provided by Crockett to first produce all the electrical energy required for operation of the sugar refinery and second to supply all the thermal processes required to refine raw sugar and produce its products; both processes are accomplished by C&H without burning any fossil fuels. The steam sales contract does not provide for any pass-through for the type of costs created by the Cap-and-Trade Regulation and incurred by Crockett. C&H, were it to have emissions of its own, would readily qualify as an energy-intensive trade-exposed ("EITE") industrial entity covered under the Regulation. It is the only cane sugar refiner west of the Mississippi, and competes nationally and internationally based on price. As a result, C&H has been unwilling to shoulder any of the load of compliance costs, including the cost of joining the system and reporting.

In light of these circumstances, Crockett renews its request for consideration of extending transition assistance for the life of Crockett's contract through 2026, whether

⁸⁸⁶ See Second Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information, at 8-9, <https://www.arb.ca.gov/regact/2016/capandtrade16/2nd15daynot.pdf>.

⁸⁸⁷ Id. at 13.

⁸⁸⁸ Crockett's contract with its counterparty, C&H Sugar, extends until 2026.

that be in the context of the future rulemaking and regulation referenced by Staff in the Second 15-Day Notice or in an earlier bullet proceeding tailored specifically to the extension of transition assistance for legacy contract generators without an industrial counterparty. Crockett believes that its request warrants expeditious consideration by Staff, given that the relief requested encompasses the third compliance period in addition to the post-2020 period. (CROCKETTCOGEN)

Response: The comments request regulatory amendments to continue legacy contract transition assistance to generators without industrial counterparties. See response to first 15-day comment B-3.2.

B-3.3. Comment:

Congratulations on AB 398 and AB 617. Thank you Assembly Member Garcia. Crockett Cogeneration is an entity with a legacy contract. We want to thank you very much in the resolution for recognizing that some entities with legacy contracts may have continuing problems, and for directing the executive officer to work to resolve them. Yeah, we look very – very much forward to working with staff and with you, and thank you so much. (CROCKETTCOGEN2)

Response: Thank you for the support. To the extent the commenter references future actions indicated in the Board Resolution, those comments are outside the scope of the current rulemaking and no further response is needed.

B-4. Industrial Allocation

B-4.1. Comment:

We appreciate staff working with covered entities in the activities under Roasted Nuts and Peanut Butter Manufacturing to amend definitions in Section 95802, relating to pistachio and almond processing. These amendments help clarify covered activities that are performed under food manufacturing NAICS code 311911. We support the changes made here and to the related activities in Section 95891 and Table 9-1: Product-Based Emissions Efficiency Benchmarks.

We also found that ARB staff made appropriate changes to the benchmark activities and related definitions for NAICS code 31151 Dairy Product Manufacturing in Sections 95802 and 95891. In table 9-1, staff is proposing modified benchmarks for a variety of activities that better reflect engineering estimates and allocate emissions to each product more accurately. We appreciate staff reinstating existing benchmarks for allocation through vintage 2018 allowances and adding new products and benchmarks for vintage 2019 allowance allocation and beyond. (AGCOUNCIL)

Response: Thank you for the support.

B-4.2. Comment:**1. Almond and Pistachio Definitions (Section 95802)**

We support the new and amended definitions for pistachios and almonds and thank the ARB for working closely with Wonderful to ensure these definitions accurately reflect the nature of the products and processes. Wonderful agrees with ARB's recommendation to include multiple definitions for almonds and pistachios, based upon processing methodology, in order to more accurately calculate the product-based energy required by each product type...

2. Inclusion of Product-Based Emissions Benchmarks for tree nuts (Section 95891)

Wonderful supports the current benchmarks proposed for pistachios and almonds as specified in Table 9-1 of Section 95891. We appreciate ARB continuing to incorporate product-based calculations of these benchmarks and are grateful for the support of ARB Staff who worked with us to ensure these new benchmarks accurately represent the emissions of this sector. (WONDERFUL)

Response: Thank you for the support.

B-4.3. Comment:

Providing Certainty for Allowance Allocations Post-2020 [§95871(d), §95890(a), §95891(a)]

The second Proposed 15-Day Amendments strike all references to post2020 industrial assistance allowance allocation.

- While we acknowledge more work (technical and communication) is needed to propose the Assistance Factors that effectively protect EITE sectors from leakage risk after 2010, completely striking Section 95871(d) and Table 8-3 creates the risk of no allocations post-2020 unless ARB makes the necessary amendments in the future. We acknowledge that the "Second Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information" indicates the intentions of ARB to propose post-2020 assistance factors in the future, Air Products would prefer to see such intentions explicitly noted in the current amendments.
- Similarly, striking the references to Table 8-3 in sections 95890(a) and 95891(a) reduces the certainty that industrial assistance allowance allocation will, indeed, be provided to partially offset the material compliance costs imposed on EITE industries and guard against emission leakage. Air Products recommends ARB indicate the intention to provide post-2020 allowance allocations consistent with their clarity that a compliance obligation will, in fact, also be imposed post-2020.

(AIRPRODUCTS)

Response: The commenter seeks to include statements of staff intent in regulatory language. Final regulation language is required by the Administrative Procedure Act to be final and certain, not an indication of staff intent. As such, the commenter's desire to see intent language in future rulemaking language is not possible to accommodate. Rather, see response to 45-day comment B-6.3 regarding staff's commitment to initiating a process to establish post-2020 assistance factors for post-2020 allocation prior to the start of post-2020 allocation. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-4.4. Comment:

EITE designations must be expanded to those industries that are EITE solely due to the indirect emissions of their purchased electricity. There are sectors which have little to no direct GHG emissions (e.g. <25,000 mt CO₂/yr) that were not historically evaluated by ARB under the industrial assistance program. Where such sectors have indirect emissions that exceed this threshold, they must be provided an allocation benchmark indicative of their compliance cost pass-through for the electricity consumed. (AIRPRODUCTS)

Response: Air Products requests additional industrial facilities receive industrial emissions leakage risk designations based on indirect emissions resulting from high levels of electricity consumption. See staff's response to the first 15-day comment B-6.32 for a discussion of why CPUC would be most qualified to provide this analysis.

B-4.5. Comment:

With respect to the treatment of borate mining and manufacturing for purposes of industry assistance, U.S. Borax is supportive of the approach proposed in the Second 15-Day Amendment Text. In particular, U.S. Borax agrees with the decision to split the NAICS Sector Code 212391 into two activities: Mining and Manufacturing of Soda Ash and Related Products and Mining and Manufacturing of Borates, Proposed Table 9-1. U.S. Borax also supports the decision to provide industry assistance to borate miners and manufacturers under the product output-based allocation methodology and the proposed emissions efficiency benchmark for borate mining and manufacturing. Finally, U.S. Borax agrees with the proposed definition of "Boric Oxide Equivalent" and the "Method to Determine the Boric Oxide Equivalent in Borate Products." Proposed § 95802. (USBORAX)

Response: Thank you for the support.

B-4.6. Comment:

We do support the Board Resolution 17-8-1 today, and we appreciate staff working to update some product definitions and modifying or creating some product-based benchmarks. These proposed amendments better reflect the activities performed by food processors, the engineering estimates benchmarks, and allocate emissions to each product more accurately. (AGCOUNCIL2)

Response: Thank you for the support.

B-5. Leakage Prevention**B-5.1. Comment:**

Section 95870-Disposition of Vintage 2013-2020 Allowances. Solar remains concerned that we will continue to be designated as a medium leakage risks for the final compliance period. This designation will reduce our assistance factor by 25%. Given Solar's unique business, with international competitors not subject to Cap and Trade or other GHG reduction mandates, Solar requests Staff propose a "High Potential" 3rd compliance period leakage designation. (SOLARTURBINES)

Response: Solar requests a high emissions leakage potential evaluation in order to better compete with "international competitors not subject to Cap and Trade or other GHG reduction mandates." Solar Turbines was assessed to have a medium leakage risk via the 2010 Appendix K methodology. See staff's responses to the 45-day comments B-6.17 for the reasons staff believes it is reasonable to reduce allocation for medium and low leakage risk sectors starting in 2018.

B-5.2. Comment:**GHG Regulatory Compliance to Date**

Windset's Santa Maria facility began operation in August 2011 and consisted of the first phase of two 32-acre greenhouses and the pack-house building. These initial greenhouses were supported by the first two boilers. In August of 2013, Windset completed construction of a second phase with two additional 32-acre greenhouses completing the four-greenhouse configuration and totaling 128-acres in area. Construction of phase two included the addition of two more boilers, for a total of four boilers at the facility. Construction is currently underway on two additional greenhouses and a second pack-house building. These two new greenhouses will utilize the same growing technologies and approach and will be supported by two new boilers. These greenhouses and boilers are expected to be online in Q3 2017 and will result in a total of six boilers operating at the facility.

Windset has been subject to the California Greenhouse Gas (GHG) reporting program and to the California Cap and Trade program since 2014, the first calendar year in which GHG emissions exceeded the 25,000 metric tons/year threshold for these programs. Windset is considered a "new entrant" to the Cap and Trade program, since our emissions exceeded the trigger level after program implementation began. Windset has also not yet been eligible for any allocations under the Cap and Trade program, since agricultural production has not been previously evaluated for leakage risk and industry assistance. Under the program, facilities are only eligible for allocations if: (1) they belong in a North American Industry Classification System (NAICS) category that is listed in Table 8-1 of the Cap and Trade regulation, or (2) the first three digits of the facility's NAICS code match those of a NAICS code listed in Table 8-1, making the facility eligible to use the energy-based allocation methodology pursuant to 17 CCR 95891(a)(3).

To date, there are no NAICS codes related to agricultural crop growth in Table 8-1. There are food processing codes listed, but these fall under the manufacturing category, rather than agriculture (Food Manufacturing NAICS codes begin with 311, while Agricultural Crop Production NAICS codes begin with 111.)

We appreciate that CARB has proposed to add a category related to Agricultural Crop Production into the Cap and Trade rule with the latest round of proposed regulatory changes. With the consideration of true-up allocations that use a two-year "look back" methodology, this will reduce the number of years for which Windset will be provided zero allocations. However, even with this change, Windset is still obligated to cover at least two years of its compliance obligations (2014 and 2015) while receiving no allocations.

The following sections contain our comments on the proposed leakage analysis performed by CARB for determining an Industry Assistance Factor for our NAICS category.

CARB Leakage Analysis

CARB evaluates leakage risk for an industry using the combination of two factors: (1) Trade Exposure and (2) Emissions Intensity. We have provided comments on CARB's calculations of these factors for our industry. However, we believe these categories provide an incomplete picture of the true leakage risk faced by our Company.

Trade Exposure

CARB's calculations of Trade Exposure evaluated NAICS 11141 ("Food Crops Grown Under Cover") based on Windset's self-identified NAICS code. This category may be technically correct when one looks at the process by which the crops are grown. Windset's facility does grow crops in a greenhouse. However, for trade exposure purposes, nearly all of Windset's competitors fall under NAICS 11121 ("Vegetable and Melon Farming.") Windset's operations involve a new and innovative technique for

growing crops inside a greenhouse that are typically grown in open fields. Windset's vegetable crops directly compete with those that are grown in open field environments. An appropriate financial analysis would be a comparison with those open field farming operations of similar vegetable crops. "Covered" crops are typically seasonal crops such as berries and they use a crop cover such as a plastic hoop house to extend their growing season by protecting the crop from rain and wind. Windset grows tomatoes, cucumbers, and strawberries, and none of these crops are grown utilizing covered hoop houses. These are all open field crops.

We have therefore performed the Trade Exposure analysis using NAICS 11121, and following the same methodology used by CARB for its original analysis. We downloaded data from the U.S. Department of Commerce and the U.S. International Trade Commission, and the results are presented in Attachment 1. As seen in these calculations, the vegetable farming category in which Windset competes should be considered to have a HIGH level of Trade Exposure (meaning calculated trade share > 19%). We also plan to provide electronic copies of our calculations and support data to CARB for review and approval.

Attachment 1 Trade Exposure Analysis

Windset Farms Trade Exposure Assessment (NAICS 111219)

	Total imports	Total Exports	Total trade	Total Shipments	Trade Exposure
2002	\$3,042,438,458	\$1,648,967,135	\$4,691,405,593	\$10,159,518,000	35.54%
2007	\$5,003,071,604	\$2,677,661,936	\$7,680,733,540	\$12,089,416,000	44.94%
2012	\$6,871,863,929	\$3,420,799,094	\$10,292,663,023	\$12,715,756,000	52.55%

TE 2012 only 52.55%<--high

TE 2007+2012 48.74%<--high

TE all years 44.34%<--high

trade share = (imports + exports) / (shipments + imports)*

*Imports, exports, and shipments data from the U.S. Census Bureau and the International Trade Commission

Trade share is categorized into three risk levels:

High: > 19%

Medium: 19 to 10%

Low: < 10%

[The commenter also attached plots of some of these data.]

Emissions Intensity

Typically, a calculation of Emissions Intensity is performed for an industrial category, in a manner similar to the calculation of Trade Exposure discussed above. We understand that, in Windset's case, CARB has performed this analysis for our facility alone. This was done because the "value added" cost information is not available for the agricultural industry as it is for industrial manufacturing categories.

CARB's analysis indicates that for the years 2013, 2014 and 2015, Windset had a calculated Emissions Intensity in the LOW category (100 to 999 MT CO₂e/\$million value added). Since additional data is now available, we have performed this analysis for calendar year 2016 and found that the calculated Emissions Intensity of our facility has grown to 959 MT CO₂e/\$million value added. This is very close to the MEDIUM category threshold, and suggests an upward trend (see Attachment 2). Please note that the information presented here is only a summary of the calculations. The supporting data contains confidential business information, which we have shared with CARB in a separate submittal.

Attachment 2 Emissions Intensity Analysis

Windset Farms Emissions Intensity Analysis

	Emissions	Value added	Emissions
2016	40,834.26	\$ 42,572,904	959.16
2015	39,807.97	\$ 53,952,909	737.83
2014	37,010.63	\$ 48,475,143	763.50
2013	23,126.66	\$ 39,174,738	590.35

emissions

intensity = metric tons CO₂e / \$million value added*

*Value added data from the Annual Survey of Manufacturers and the U.S. Economic Census

The emissions intensity is categorized into four risk levels:

High: > 5000 mtCO₂e/\$M value added

Medium: 4999 to 1000 mtCO₂e/\$M value added

Low: 999 to 100 mtCO₂e/\$M value added

Very Low: < 100 mtCO₂e/\$M value added

This trend may be due, in part, to our increasing investment in the Santa Maria facility. At the start of its operation in 2011, the facility operated two boilers. Two additional boilers came online in 2013, allowing us to expand production but resulting in higher emissions. Construction is currently underway on two additional greenhouses, an associated pack shed, and includes two new boilers. These new greenhouses and boilers are expected to be online in Q3 2017.

In addition to the higher emissions, when compared to the industry most closely resembling Windset and its operations, the NAICS category "Vegetable Farming", the emissions intensity is not even comparable. Field vegetable farming techniques have little or no emissions, whereas Windset has a significant amount. Therefore, we request that Windset's emission intensity is rated as high.

Shifting Production

Beyond the calculations of Trade Exposure and Emissions Intensity, there are a number of factors that contribute to a very real risk of emissions leakage, and should be considered in CARB's determination. Windset has been expanding the Santa Maria facility, and we plan to continue that trend if we can operate in a favorable business environment. We also operate greenhouse facilities in Nevada and British Columbia, and we are actively evaluating expanding these existing facilities as well. Windset is also evaluating the development of new similar greenhouse facilities in other states and countries. From a business case perspective, we are developing strategies to potentially shift production out of California should Cap and Trade costs become too high to manage. This decision will be made in the short term, affecting our production during the Third Compliance Period of the Cap and Trade program (2018 to 2020). So, we are eager to work with CARB to obtain a determination on this matter as quickly as possible.

As we have demonstrated, the vegetable crop production industry is highly trade exposed, and sensitive to even small changes in production costs. Greenhouse farming requires an intensive capital investment compared to field farming and thus operating costs become large factors when evaluating the placement of capital in certain regions. This disparity and exposure to sensitivity is even more evident when competing against low capital investment field crops in the same product category.

Conclusion

Based on the information presented here, we believe that CARB should grant the Agricultural Crop Production category with a 100% Industry Assistance Factor for the Third Compliance Period of the Cap and Trade program. Use of a lower factor would place an unnecessary burden on Windset, and potentially result in the shifting of crop production (and therefore leakage of GHG emissions) outside of California. (WINDSET)

Response: Windset discusses industry-specific data that they have developed, and believe would change the emissions leakage potential evaluation conducted

by staff in advance of the first 15-day package. Windset requests an AF of 100% for the third compliance period. Windset's information in support of the request was received after the second 15-day change, at which point staff was unable to consider it as input for the second 15-day package. For more on how staff set the AF applicable to Windset Farms during the third compliance period, see staff's response to first 15-day comment B-6.21. Staff encourages Windset's continued engagement in a subsequent rulemaking to establish post-2020 AFs. See the response to 45-day comments B-6.3 and B-6.14 for staff's openness to receiving high-quality industry data.

B-5.3. Comment:

As ARB designs the next phase of cap-and-trade, Ag Council believes priority should be given to sustaining a reliable and stable supply of safe, high quality and affordable domestic food. California farmers and food processors produce food to the highest environmental and labor standards in the nation. However, complying with lower-emission and fuel-efficient standards comes at a financial cost. Higher costs put farmers and food processors at a disadvantage, since we are subject to global commodity markets and cannot simply raise prices to cover costs. Our main concern with ARB's cap-and-trade program is that it will lead to an increase in emissions leakage over time, as California-based entities continue to lose market share to competitors in other jurisdictions. A loss of market share could manifest in greater exposure to lower-cost imports and challenges in marketing California produced food. The declining emissions cap in the program allows the state to retain 100 percent assistance factors for regulated sectors and still achieve the greenhouse gas (GHG) emissions reduction targets, without increasing the risk of emissions leakage. We urge ARB to protect our food supply and create a flexible policy framework that will achieve cost-effective and technically feasible GHG emissions reductions. (AGCOUNCIL)

Response: Ag Council requests a "flexible policy framework" to combat emissions leakage and implies that such a framework would require a higher assistance factor for food processors to prevent a loss in market share. Staff believes that it is appropriate to periodically assess emissions leakage risk for all industrial sectors and change assistance factors when data show that the leakage risk for any sector has increased or decreased.

See staff's response to the 45-day comment B-6.1 for why staff believes 100 percent AFs for medium and low leakage risk sectors come at a cost, and are not needed to minimize emissions leakage to the extent feasible.

B-5.4. Comment:

EDF appreciates staff's commitment to utilizing the best available data and analysis to determine how much leakage protection is warranted for each sector. We support

ARB's decision to continue to analyze the inputs that will inform post-2020 industrial allocation.

EDF has consistently supported some allocation of allowances to support leakage protection. As staff has articulated it is important to continue to balance the goal of minimizing emissions leakage with the goal of ensuring that allowance value is used most prudently and for the benefit of all Californians, especially those in disadvantaged communities.

Allowances represent a valuable asset that businesses can use or sell depending on their need. As such, the default absent a strong regulatory need like leakage assistance should be auctioning, as is consistent with the overall design of the California's cap-and-trade program. (EDF)

Response: Staff thanks EDF for their support of the goal of balancing emissions leakage prevention with allocating allowance value for other uses. See staff's response to the 45-day comment B-6.1 for why staff believes medium and low leakage risk sectors can now accommodate a reduction in their transition assistance starting in 2018.

B-5.5. Multiple Comments:

The Global Warming Solutions Act of 2006 (AB 32) and Senate Bill 32 (2016), require ARB to seek to limit the leakage of emissions out of California in its implementation of GHG reduction regulations, including the market-based mechanism. CMTA appreciates that ARB staff deleted the proposed reductions in the assistance factors for the post-2020 period in the Second 15-Day Amendment. While the amendment leaves in place a reduction in assistance factors for the Third Compliance Period (2018-2020), placing manufacturers at greater leakage risk, further reductions would have created far more pressure to relocate production out of California leading to additional emissions leakage

Maintain Industry Assistance at 100 percent

CMTA continues to recommend that ARB maintain industry assistance at 90 percent through the Third Compliance Period and post-2020 for all industry sectors. This change would delete the planned drops for medium and low leakage risk categories to 75 and 50-percent and beyond resulting in greater protection against emission leakage and job loss.

It is important to note that this is not necessary to meet California's AB 32 (2006) goals or those established under SB 32 (2016). (CMTA)

Comment:

TRADE EXPOSURE PROTECTION IS NECESSARY

The risk of leakage due to costs incurred by California industry, but not their competitors is high. In the last round of amendments to the Cap-and-Trade regulation (2013-2014),

CARB extended 100% of the assistance factor into the second compliance period. As it was in the 2013-2014 timeframe, California's market remains largely isolated from other markets where more cost-effective reductions exist. Accordingly, an extension of 100% industry assistance is still warranted until such time that leakage risk is eliminated, both to maintain the environmental integrity of the program and to protect California jobs and the state's economy. We appreciate the CARB's decision to delay the allocation of post-2020 assistance factors pending additional analysis and look forward to participating in the discussion moving forward. (CALCHAMBERCOMMERCE)

Comment:

3. Removal of Allowances for Vintage Years 2021 and beyond (Section 95871)

Wonderful supports the removal of Table 8-3 and the text in Section 95871(d). We appreciate ARB taking into account the concerns raised by a number of stakeholders regarding the leakage studies and methodology utilized to calculate these assistance factors. The removal of this section from the Proposed Regulations will provide ARB and stakeholders with additional time to discern the applicability of these studies, as well as afford industry the opportunity to work with ARB to determine viable alternative solutions for the future of the Cap-and-Trade Program. (WONDERFUL)

Comment:

UPI supports deferring consideration of post-2020 Assistance Factors for industrial allocation until a later time to allow for full and fair review of this very important issue, and greatly appreciates Staff's consideration of comments made by UPI and others regarding the shortcomings of the leakage studies and the potential negative impacts of the previously proposed sharp decline in post-2020 Industry Assistance Factors for the Cap-and-Trade program. (POSCO)

Response: Staff thanks the commenters for their support of implementing a robust stakeholder process to provide staff input in developing a post-2020 assistance factor methodology. See staff's response to the 45-day comment B-6.1 for the reasons allowance allocation does come at a cost to other alternate uses of allowance value, as well as staff's belief that medium and low leakage risk sectors can accommodate a reduction in their assistance factors starting in 2018. In any case, this rulemaking did not modify any third compliance period assistance factors,⁸⁸⁹ so comments seeking changes to those are outside the scope of this rulemaking. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

⁸⁸⁹ Four new industrial sectors' emissions leakage risk was evaluated using the 2010 ISOR Appendix K methodology.

B-5.6. Comment:

Ag Council supports ARB's decision to delete table 8-3 and the text of section 95871(d). Delaying implementation of assistance factors for vintage year 2021 and beyond is important, since there are many outstanding issues with the previously proposed assistance factor methodology. We believe there was a real possibility that cap-and-trade would have increased emissions leakage under Attachment B in the first 15-day amended text released on December 21, 2016.⁸⁹⁰ Data limitations and methodological choices used to conduct the leakage studies caused the authors of the studies to underestimate emissions leakage risk. Consequently, ARB proposed assistance factors that were too low to effectively mitigate emissions leakage for the food processing industry, as noted by Dr. Richard Sexton of U.C. Davis.⁸⁹¹ ...

We believe to achieve the 2030 goals for SB 32, the existing cap-and-trade program needs some improvement to minimize leakage in order for it to become a more meaningful program.

[The commenter attached a document titled "Evaluation of the California Air Resources Board's Proposed Determination of Industry Assistance Factors for Post-2020 Compliance with AB32," by Richard Sexton and Steven Sexton, referred to in the preceding footnote, which critiques the Fowlie et al. and Gray et al. leakage studies commissioned by ARB and their use to calculate assistance factors proposed in 45-day changes.] (AGCOUNCIL)

Response: Thank you for the support.

B-5.7. Comment:

Section 95871-Disposition of Allowances from Vintage year 2021 and beyond. The recommended regulatory changes do not include any proposed allocation assistance for Solar Turbines. We acknowledge that Staff stated they believe continued assistance is necessary, and committed to proposing a new table 8-3 (or something similar), at a later undetermined date. Solar and other California business remain trade exposed, particularly given that no western states have joined the AB32 program, or enacted equivalent regulations on manufacturing. Solar has reduced our carbon footprint since 2006, and is committed to making more progress. However, assistance is still necessary, particularly for trade exposed companies like Solar that compete in international markets, to free up capital for plant investments. Solar requests that the Board adopt a resolution directing Staff to propose post 2020 assistance factors at the earliest possible date so industry can adequately prepare operational and compliance strategies that will be necessary in just a few years. (SOLARTURBINES)

⁸⁹⁰ <https://www.arb.ca.gov/regact/2016/capandtrade16/attachb.pdf>

⁸⁹¹ Sexton, R.J. and Sexton, S., (2017). Evaluation of the California Air Resources Board's Proposed Determination of Industry Assistance Factors for Post-2020 Compliance with AB32.

Response: Solar Turbines comments that despite the GHG efficiency investments they have made, and plan to continue to make, continued allowance allocation is warranted by current market conditions (e.g., significant trade exposure). Solar Turbines also emphasizes that establishing post-2020 assistance factors as soon as possible will help with medium-term business planning. Staff agrees that allowance allocation will continue to be an important tool in minimizing emissions leakage to the extent feasible in the post-2020 period. See staff's response to the 45-day comment B-6.1 regarding staff's commitment to initiating a process to establish post-2020 assistance factors for post-2020 allocation prior to the start of post-2020 allocation. With the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-5.8. Comment:

UPI also appreciates Staff's commitment to continuing to provide industrial allocation at levels sufficient to minimize emissions leakage post-2020. UPI supports Staff's proposal to initiate a deliberative process with input from industrial as well as other stakeholders to establish a robust and transparent framework for post-2020 Assistance Factors, and looks forward to working with Staff in this effort in order to ensure the achievement of both the environmental objectives of the Cap-and-Trade program and the sustainability of California industry. (POSCO)

Response: Thank you for the support.

B-5.9. Comment:

Section 95891. Allocation for Industry Assistance

The current proposal will result in several troubling changes for the Cap-and-Trade Program. CCEEB remains concerned about a further shifting of the cost burden through a reduction of industry assistance. Assistance for trade exposed companies is a simple method of protection to avoid both environmental and economic leakage. California businesses are trade exposed unless their competitors are in a linked jurisdiction. In the absence of national or international programs comparable to what exists in California, CCEEB requests that the ARB maintain current industrial assistance factors. (CCEEB)

Response: CCEEB requests indefinite extensions of 100 percent assistance factors. See staff's response to the 45-day comment B-6.1 for the reasons 100 percent assistance factors are not necessary for all sectors, starting in 2018. Staff agrees that a re-evaluation of industrial assistance factors may be warranted as existing carbon regimes are strengthened, or new carbon regimes are implemented, including the carbon programs mentioned in staff's May 2016

workshop.⁸⁹² In addition, this rulemaking did not modify any third compliance period assistance factors,⁸⁹³ so comments seeking changes to these assistance factors are outside the scope of this rulemaking.

B-5.10. Comment:

Post-2020 Assistance Factor

CCPC and others believe that there are many outstanding issues with previously proposed assistance factor methodologies. While CCPC thanks staff for delaying a decision on assistance factors post-2020, we would appreciate assurances that this additional time will be used to do a better forward looking analysis, not to simply put the burden on industry to counter flawed studies and confidential data with each sector's own work. Furthermore we would note that there would be no down side from an environmental perspective if ARB moved forward in providing the necessary industry assistance. In fact, the only downside comes when industry assistance is withheld, namely in the form of economic leakage. As we've stated, we believe to achieve the 2030 goals for SB 32, the existing cap-and-trade program needs some improvement to minimize leakage in order for it to become a more meaningful program. (CCPC)

Response: See staff's response to CCPC's first 15-day comment B-6.16 for the reasons staff believes a reduction in assistance factors is warranted and beneficial starting in 2018 for medium and low leakage risk sectors. See staff's response to the 45-day comment B-6.2 regarding receiving industry data and suggestions during a subsequent rulemaking to establish post-2020 assistance factors. Moreover, with the recent enactment of AB 398, the Legislature has provided direction on what the assistance factors must be for industrial allocation commencing in 2021. ARB will initiate a rulemaking process to implement the AB 398 requirements for the post-2020 Cap-and-Trade Program.

B-5.11. Comment:

ARB Should Consider Retaining and Expanding "Non-Standard" Cap Adjustment Factors for Industrial Sectors with High Levels of Process Emissions [§95891 - Table 9-2]

Air Products encourages ARB to consider continued use of non-standard cap adjustment factors, post-2020, for industrial sectors that have a significant portion of their total GHG emissions derived from the inherent process chemistry (i.e. "process emissions"). The industry sectors afforded such consideration should include all those with process emissions representing more than 50% of total emissions – such as hydrogen production (Industrial Gas Manufacturing – NAICS code 325120). The

⁸⁹² May 18, 2016. "Public Workshop on Emissions Leakage Studies for Cap-and-Trade Program" Slide 17. <https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/staff-leakage-workshop-methodology.pdf>

⁸⁹³ Four new industrial sectors' emissions leakage risk was evaluated using the 2010 ISOR Appendix K methodology.

increased Cap Adjustment Factors will afford greater protection to this subset of the EITE industry sectors that are particularly vulnerable to leakage. (AIRPRODUCTS)

Response: See the response to a similar request in first 15-day comment B-6.34.

B-5.12. Multiple Comments:

Specifically we want to applaud ARB for recognizing the need to include in today's resolution the need to minimize emissions leakage by using the same 2013 through 2017 assistance factors to industrial entities for 2018 through 2020. We really do appreciate the thought and the process that went beyond that. So, again, thank you. And we look forward to working together as we move ahead in this process. (CCPC2)

Comment:

I want to thank the Board and particularly the staff as well who spent countless – though I'm sure they can count how many hours they spent on it – what I'm sure feels like countless hours working on this important program... Specifically to the regulation, we appreciate the direction in the resolution to continue the support for highly trade-exposed industries. This will help industries such as cement manufacturing and others that face significant issues related to process emissions, which are out of their direct control or ability to reduce.

Additionally we're very appreciative of the inclusion of the direction to staff to address the third compliance period industry-assistance factors to continue that hundred percent level that's been in place, you know, since the beginning of this program. We believe that's critical to supporting continued manufacturing in the State of California, particularly in those sectors that were slated for significant reductions, such as food processing, paper manufacturing as well. We appreciate the – again, the time that the staff and the Board have put into this. We appreciate the leadership of Assembly Member Garcia as well on AB 398, and working for – looking forward to working with the Board and staff to implement additional changes for the post-2020 period. (CMTA2)

Comment:

Ag Council would also like to express our thanks for the language in the resolution that addresses the needs to minimize leakage of California businesses. We support ARB's efforts to address this concern in the rulemaking process by implementing the requirements of AB 398. We'd like to thank the Board and Assembly Member Garcia for your leadership, and thank you for the opportunity to comment today. (AGCOUNCIL2)

Comment:

I want to thank staff for really the last 10 years in working with Solar Turbines to understand our business under this program. We know they have a lot of companies to work with, and we've really appreciated both their visits, their time on the phone, the

times in meetings; and it's been really critically important for our management to understand how staff has been working with us.

The proposed industry assistance is particularly important for international companies like Solar Turbines. We participate in an international market. All of our competitors are based outside of the U.S. And this will give us time to work with our customers, as we help to -- as we try to manage their expectations for the testings of their products in our facilities in California. We are committed to doing our part, to lower carbon manufacturing, and we appreciate your consideration. (SOLARTURBINES2)

Comment:

We support the resolution that's in front of the Board today, specifically the item on page 14 that maintains the current assistance factors from the second compliance period into the third. Maintaining these factors will -- is critical to our food processing industry, as I said, because they cannot pass on any increased cost on to the consumers. This will ensure that our food processing industry can remain in California and also that our agricultural products continue to have a home in California.

We look forward to the implementation of AB 398 and continuing to work with the Board and staff and with Assembly Member Garcia on this implementation. (AGPROCESS)

Comment:

We have 21 members who are subject to the cap-and-trade. Most of those are located in disadvantaged communities. We needed this protection, as we were going to lose significant amount of allowances in the third compliance period. So we are all in favor of these amendments, not only extending the cap-and-trade to 2030 but also the amendments that will change the third compliance period and save us in that area. (FOODPROD)

Comment:

We do appreciate the fact that there is a resolution here acknowledging the difficulty that it will be for industry to meet the goals moving forward in achieving our 2030 climate goals, which are some of the most difficult in the world right now. And so we appreciate the acknowledgments that industries need assistance to be able to comply and that they need -- we want them to stay here in the State of California and be some of the cleanest and greenest that there are. So we appreciate all of the efforts and we look forward to working with you in the future. (CALCHAMBERCOMMERCE2)

Comment:

I'm here to echo and support the comments made by Lauren Hajik [AGPROCESS] and John Larrea [FOODPROD]. And I'm also here to personally thank the staff for the work and efforts that went into addressing our concerns as a processing facility providing jobs and meeting these regulations. It is greatly appreciated. (BOSWELL)

Response: Thank you for the support. To the extent the commenters reference future actions indicated in the Board Resolution, those comments are outside the scope of the current rulemaking and no further response is needed.

B-5.13. Comment:

We appreciate the hard work that you and staff have put into this and we look forward to participating in another couple years of hard work to follow as these programs get developed. We recognize the compromises that were necessary in order to get this package put through. We'd also like to make sure that we all remember that this is fundamentally an environmental program meant to protect the environment and the problems with the climate change. It's based on some principles that polluters should pay for the pollution they put into the atmosphere. And, this is a scientifically-based program.

We'd like to note that ARB staff, in partnership with several independent researchers, have done a lot of great work on several subjects about where certain targets should be set particularly on industrial systems. And we would really like to encourage staff to the greatest extent possible to use the science that ARB staff have done as they set industrial assistance both for the upcoming compliance period as well as for post 2020. (NEXTGEN)

Response: Thank you for the support. To the extent the commenter references future actions indicated in the Board Resolution, those comments are outside the scope of the current rulemaking and no further response is needed.

C. ELECTRICITY

C-1. Clean Power Plan (CPP)

C-1.1. Comment:

Do not commit California to continuing Cap-and-Trade through the Clean Power Plan. Since carbon trading cannot be verified, ensure that the Clean Power Plan power purchases are from sustainable, renewable power plants. (EJAC)

Response: See response to 45-day comment D-1.2.

C-2. Energy Imbalance Market (EIM) Imports

Accounting For Imported Electricity Emissions from EIM and Addressing Emissions Leakage

C-2.1. Multiple Comments:

With respect to the bridge solution, the ISO also appreciates ARB's acknowledgment that it will be an interim solution until the ISO implements enhancements to its optimization. In consultation with ARB and other stakeholders, the ISO is examining proposed enhancements to its market optimization in order to

more accurately capture emissions associated with the dispatch of external resources to serve ISO load.⁸⁹⁴ The ISO also proposed modifying how the market optimization will attribute EIM transfers serving ISO load to EIM participating resources in order to address concerns that the current dispatch may create emissions from secondary dispatches when there is an EIM transfer to serve ISO load. At a high level, the ISO proposes to run its least cost dispatch optimization in two steps. First, the ISO proposes to identify the least cost dispatch of resources to serve EIM load without allowing EIM transfers to serve ISO load. This step will provide an economic base of resource schedules outside California from which the ISO can then identify incremental EIM dispatches to serve California load. Second, the ISO will run its least cost dispatch optimization allowing transfers to serve California load. The ISO will attribute EIM transfers serving ISO load to output from resources above their economic base schedules identified in the first step.

The ISO plans to resume its stakeholder initiative to design these enhancements and will seek authority from its Board of Governors. Prior to seeking authority from its Board of Governors to implement these enhancements, the ISO plans to demonstrate, through a market simulation, how these enhancements account for greenhouse gas emissions from EIM participating resources serving ISO load. ARB, as well as all stakeholders, will have the ability to review the inputs and results of this market simulation. After the ISO obtains authority from the Board of Governors, the ISO will submit any necessary tariff revisions to the Federal Energy Regulatory Commission. In that filing, the ISO will identify an implementation date for its market design enhancements. The ISO plans to consult with ARB staff and stakeholders with respect to the implementation date for these enhancements.

While the ISO supports ARB's bridge solution, ARB should only apply it on an interim basis to provide time for the ISO and its stakeholders to develop and implement refinements to the EIM optimization. For this reason, the ISO requests ARB to direct its staff to prepare a supplemental amendment to these regulations. The supplemental amendment would retire ARB's proposed "bridge solution" and rely on the ISO's enhanced optimization to identify which EIM resources were dispatched to serve ISO load. ARB should begin the process to amend its regulation when the ISO has authority from its Board of Governors to implement enhancements to ISO's market optimization to more accurately account for emissions associated with the dispatch of EIM resources to serve ISO load. ARB should make this amendment effective on the date the ISO implements these enhancements. (CAISO)

⁸⁹⁴ More information on the ISO's stakeholder initiative is available at the following website: <http://www.caiso.com/informed/Pages/StakeholderProcesses/RegionalIntegrationEIMGreenhouseGasCompliance.aspx>

Comment:

The Energy Imbalance Market “EIM” bridge solution should not be implemented; instead, the ARB should wait until the California Independent System Operator (CAISO) has developed its preferred, vetted solution. The EIM outstanding, or secondary dispatch, emissions contemplated by ARB may become a greater issue as more and more entities participate in the EIM. As such, the undefined, “black box” calculation of total EIM emissions proposed by ARB may have larger impacts on the EIM market and Cap-and-Trade cost containment than stakeholders participating in this rulemaking can reasonably estimate. The CAISO has a robust stakeholder process for considering changes that may impact the energy markets that they operate, and is already working on a solution that would include technical changes to its markets that would help ARB capture the emissions that it seeks to capture in the Cap- and-Trade program while also providing a proper cost signal to better inform real-time economic dispatches of generating resources within the EIM. Furthermore, the interim solution proposed in the Cap-and-Trade changes is not bound by a defined time period. Any potential solution that could become permanent deserves much more study and stakeholder input than has been dedicated to this issue as part of this Cap-and-Trade rulemaking process. (MODESTOID)

Comment:

M-S-R also believes that any interim solutions or proposed temporary changes to the Cap-and-Trade program to address accounting for emissions in the EIM would similarly result in uncertainties in the market. Instead of adopting an interim revision in the form of the “bridge solution,” CARB should not make any amendments to the Cap-and-Trade program until the California Independent System Operator (CAISO) has completed its stakeholder process to address EIM GHG accounting. The proposed “interim solution” is not confined to a defined time period, nor does it account for the potential to adversely impact the EIM. Further, there will likely be market disruptions and uncertainty associated with the period of overlap between the time when the CAISO completes its process and approves tariff amendments that implement the new accounting mechanism and when a new CARB rulemaking is completed to strike the interim solution.⁸⁹⁵ (M-S-R)

Comment:

NCPA also urges the Board to direct that the revisions to the regulation that would adopt the “bridge solution” (described in proposed revisions to section 95852(b)(1)(D)) clearly delineate how long the proposed interim solution will be utilized. In the alternative, the bridge solution should be removed, and the regulations should retain the *status quo* until

⁸⁹⁵ Recent discussions at the Western Renewable Energy Generation Information System (WREGIS) regarding carbon attributes associated with transactions in the EIM may further complicate the issue of carbon accounting and application of an interim solution developed outside of the CAISO’s stakeholder process.

the ongoing CAISO rulemaking process has been completed and a final accounting metric has been approved. (NCPA)

Comment:

Additionally, PGE is supportive of the proposed bridge solution to account, on an interim basis, EIM GHG secondary emissions for serving California load...

PGE requests that CARB add explicit language into the rule package that would remove the GHG accounting bridge solution once the CAISO two-pass model has been developed, tested and implemented. This would help prevent the delay of a rule notice and comment period once the two-pass model is ready to be implemented. If this is not possible, then PGE requests that CARB clearly indicate in this rule package that implementation of the bridge solution is temporary, and that CARB will propose further regulatory amendments to reflect the two-pass model once finalized.
(PORTLANDGENELEC)

Comment:

Powerex strongly encourages CARB to continue to coordinate with CAISO regarding implementation timelines of the two-pass solution. While Powerex supports the interim solution, Powerex believes that the two-pass solution is a more appropriate long-term approach. As outlined in Powerex previous comments,⁸⁹⁶ Powerex is optimistic that once the two-pass solution is implemented, it will ensure that the EIM accurately recognizes the GHG emissions from out-of-state resources dispatched to serve California load, while at the same time it will avoid “leakage” through the EIM and will properly consider the GHG costs when dispatching low- or zero-emitting out-of-state resource over high-emitting out-of-state resources (POWEREX)

Response: See staff’s responses to the 45-day comment D-2.1 and first 15-day comments D-2.1 and D-2.5 for staff’s reasoning behind the bridge solution, as well as staff’s responsibility under AB 32 to implement it during this rulemaking.

With regard to CAISO and PGE’s request for a supplemental amendment that would retire the proposed bridge solution, ARB declines to make changes at this time, given that the details of the enhanced optimization are not yet fully developed or approved as an addition to the CAISO tariff. Because accurate emissions accounting is of critical importance, it is necessary and appropriate for ARB staff and stakeholders to carefully review that optimization design before the Cap-and-Trade Regulation is amended to accommodate it. If CAISO finalizes two-pass market optimization, ARB will consider and propose appropriate regulatory changes to align its regulations with such improvements at that time. ARB staff looks forward to working with CAISO and the public as this process continues.

⁸⁹⁶ *Ibid* at page 1.

Miscellaneous

C-2.2. Comment:

II. The ISO supports elimination of text that would make the ISO a reporting entity under ARB's mandatory reporting regulation

In Section F of ARB's Second 15 Day Notice for its mandatory reporting regulation, ARB explains that it has removed the ISO as a reporting entity under the mandatory reporting regulation for purposes of the EIM. The ISO appreciates and supports this modification. As explained in its earlier comments, the ISO is a market operator and transmission planning entity. In conducting these activities, the ISO is not a source of emissions under ARB's cap and trade regulation although the ISO may have possession of market data that could assist ARB's implementation of its regulatory programs.

ARB has issued a subpoena to the ISO to obtain information concerning transfers of electricity to serve California load in connection with administering California's cap and trade program and mandatory reporting regulations.⁸⁹⁷ The ISO will work to ensure ARB receives responsive information pursuant to that subpoena. In addition, the ISO is willing to meet with ARB staff to clarify any information provided pursuant to the subpoena, and will use best efforts to respond to ARB's questions related to this information. (CAISO)

Response: The CAISO reporting provisions raised by commenter are outside the scope for this Cap-and-Trade rulemaking as those provisions are in the Mandatory Reporting Regulation. This issue is addressed in the 2017 FSOR for the Mandatory Greenhouse Gas Reporting Regulation. Regardless, ARB staff notes here that, in the second 15-day amendment package for MRR, staff removed CAISO as a reporting entity under MRR and instead will receive the necessary information from CAISO through an annual subpoena process. Staff thanks CAISO for its commitment to responding in a timely manner to ARB staff's subpoenas and other requests for information.

C-2.3. Multiple Comments:

I. The ISO supports the revisions in ARB's 15 Day Notices that relate to the Western EIM

In Section G of the 15 Day Notice related to the cap and trade regulation, ARB states that it is modifying Section 95852(b)(2)(A)(10) to reinstate language that clarifies that electricity imports to the ISO through the Western EIM do not constitute resource shuffling. ARB explains that pending enhancements to the ISO's optimization, ARB is proposing to implement a "bridge solution" to account for

⁸⁹⁷ <http://www.caiso.com/Documents/2015-04-01CaliforniaAirResourcesBoardSubpoena.PDF>

greenhouse gas emissions associated with secondary dispatches that may occur in connection with EIM transfers.⁸⁹⁸ Under the bridge solution, ARB proposes to calculate emissions for EIM transfers that constitute electricity imports into California at the emissions rate for unspecified sources, less emissions reported by EIM participating resource scheduling coordinators. Beginning January 1, 2018, ARB would retire current vintage allowances designated by ARB for auction that remain unsold for more than 24 months in the amount of the calculated outstanding emissions. As stated in the 15 Day Notice, ARB is satisfied that the approach does not constitute resource shuffling in the Western EIM. The ISO appreciates ARB's willingness to make this change and reinstate language clarifying that EIM transactions do not constitute resource shuffling.⁸⁹⁹ (CAISO)

Comment:

EIM transactions are properly excluded from the definition of resource shuffling. M-S-R appreciates the proposal in the revised 15-day Changes to retain the Energy Imbalance Market (EIM) exception from the definition of resource shuffling found in the current regulation. The original change to remove this exception would have caused greater uncertainty for market participants while providing no greater accuracy in accounting for GHG emissions resulting from the EIM. (MODESTOID)

Comment:

Imports from Energy Imbalance Market Transactions are Properly Excluded from the Definition of Resource Shuffling

The Second 15-Day Changes would correct a mistake from the original proposed amendments regarding the treatment of imports in the California Independent System Operator's (CAISO) Energy Imbalance Market as resource shuffling. Section 95852(b)(2)(A)(10). NCPA supports the change that would retain the exception for these transactions from the definition of resource shuffling. (NCPA)

⁸⁹⁸ The term "secondary dispatch" refers to the effect of lower GHG emitting resources supporting EIM transfers to serve ISO load while higher GHG cost resources backfill to serve load in EIM Entities' balancing authority areas. When the ISO dispatches EIM resources to support a transfer to serve California load, the ISO seeks to minimize total costs associated with these transfers. Least cost dispatch can have the effect of attributing transfers to serve California load to lower-emitting EIM resources. In some instances, higher-emitting resources will need "to backfill" this dispatch to serve load outside of California.

⁸⁹⁹ Irrespective of the bridge solution, EIM transactions do not constitute resource shuffling under ARB's regulations. Resource shuffling, as defined by ARB, is a "plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation." ISO market dispatches do not meet this definition because they are not a plan, scheme or artifice undertaken by a first deliverer of electricity. Moreover, the safe harbor from the prohibition against resource shuffling currently extends to transactions in the ISO's real-time market transactions. The EIM is the ISO's real-time market extended to other balancing authority areas in the West.

Comment:

SECTION 95852. RESOURCE SHUFFLING/EIM CONSIDERATIONS

PG&E supports ARB's change to Section 95852(b)(1)(B) to clarify that CAISO EIM transactions do not constitute resource shuffling. We agree that the interim measure proposed in the ARB's December 2016 15-day notice package and the permanent measures being discussed in the CAISO Regional GHG Initiative will address ARB concerns about assigning GHG obligations for "leakage" emissions. PG&E expects that the ARB and CAISO will achieve their objective of accurately accounting for these EIM emissions. PG&E fully supports clarifying that the results of the CAISO dispatch model do not constitute resource shuffling. This change helps avoid a potential dampening of EIM participation. (PG&E)

Comment:

PGE is supportive of CARB's proposal to retain the current resource shuffling safe harbor for short-term transactions as EIM transactions do not constitute resource shuffling under CARB's regulations. (PORTLANDGENELEC)

Comment:

Powerex supports reinstating § 95852(b)(2)(A)(10), which clarifies that power imports via the CAISO EIM do not constitute resource shuffling. As Powerex discussed in its previous comments,⁹⁰⁰ the removal of this language would create regulatory uncertainty for EIM Participants and may do little to encourage the timely development of a two-pass solution. (POWEREX)

Comment:

SCE supports the clarification that CAISO Energy Imbalance Market transactions do not constitute resource shuffling.⁹⁰¹ This regulatory change makes clear that the results of the CAISO dispatch model do not constitute resource shuffling, which in turn helps to ensure that the benefits of EIM participation can continue to be realized and that market participation continues to be encouraged. (SOCALEDISON)

Comment:

PGE submitted comments to CARB on September 19, 2016, and again on January 20, 2017, on their proposed amendments to the Regulations. In both sets of comments, PGE: (1) opposed the removal of the resource shuffling safe harbor for EIM transactions; and (2) urged CARB to implement an interim measure (or "bridge solution") without disrupting the EIM dispatch algorithm to account for greenhouse gas

⁹⁰⁰ See Comments of Powerex Corp. on the Proposed 15-Day Amendments to the Cap-and-Trade Regulation and the Mandatory Reporting Regulation available at <https://www.arb.ca.gov/lists/com-attach/161-capandtrade16-U2ECNFRkVjLIFJi.pdf>.

⁹⁰¹ Section 95852(b)(1)(B)

(“GHG”) secondary emissions while a long-term solution is designed and implemented by CAISO. PGE is pleased to see that both of these concerns appear to be addressed in the 2nd 15 day amendment text to the Regulations. (PORTLANDGENELEC)

Response: Staff thanks stakeholders for their support of reinstating the safe harbor for EIM imports. See staff’s response to 45-day comment D-2.5 for a discussion of staff’s determination to reinstate the EIM safe harbor. Staff also thanks Portland General Electric for their support of the bridge solution, which is discussed in response to 45-day comment D-2.1.

C-3. Renewable Portfolio Standard (RPS) Adjustment

C-3.1. Comment:

The ARB Should Continue to Evaluate the Implementation of the RPS Adjustment Rules to Ensure that Market Participants Are Not Unjustly Benefiting from Specified Source Power Claims at the Expense of California Ratepayers.

TID supports the retention of the RPS Adjustment provisions. This is extremely important for TID because a major part of our RPS compliance is tied to the 2009 purchase of the Tuolumne Wind Project located in Washington. TID relies on the RPS adjustment to ensure that our ratepayers receive the zero GHG emissions benefit and RPS compliance value of that investment (i.e., the Green Attributes). The retention of the RPS Adjustment is an example of Staff harmonizing RPS with Cap & Trade as directed by AB 32. As stated in the 2010 Final Statement of Reasons (FSOR) (p. 57), “The RPS adjustment provision accomplishes the purpose of reducing a deliverer’s compliance obligation by accounting for renewable imports”.

While we are not requesting any adjustments to allowance allocations based on the RPS adjustment rules, we believe that the ARB must do more to minimize specified source claims of null power. By removing the requirement to report REC serial numbers from Section 95852(b)(3), the current rules will create an incentive to purchase null power and claim the Green Attributes for that power even though the purchaser did not receive the Green Attributes. This incentive has and will continue to harm California ratepayers. The ARB should continue to evaluate changes to the RPS adjustment either in regulation or in guidance language that would remove the incentives to import null power into California. (TURLOCKID)

Response: Thank you for the support regarding the retention of the RPS adjustment. For a discussion of the intersection between specified source reporting requirements and the RPS adjustment, see the response to the first 15-day comments in section D-3. Staff also notes that guidance does not, and cannot, alter regulatory provisions. Rather, it can provide assistance and further explanation.

C-3.2. Comment:

The RPS adjustment could be improved outside of the rulemaking process by adding clarification to the ARB's guidance documentation. Through extensive discussions between affected EDUs and ARB staff regarding the RPS adjustment provision, it has become clear that this complex, important provision of the Cap-and-Trade program would benefit from more detailed and specific direction for how the provision should work. Implementation of the RPS adjustment is a nuanced process that weaves together complex reporting and verification requirements, the technical and regulatory differences between directly delivered electricity and imported specified source electricity, the Renewable Portfolio Standard (RPS) program and its Renewable Energy Credits (RECs), the behavior of third parties in the energy market, electronic tagging of energy purchases, and early-action investments in renewable energy resources by EDUs' ratepayers. With such complexity, it is critical to ensure that reporters and ARB staff are in alignment regarding how the provision should work and how it is implemented. By enhancing the regulatory guidance available through the ARB's Cap-and-Trade website to better describe the RPS adjustment and establish a single, universal understanding of the provision amongst all parties, the issue could be addressed without any further regulatory changes. As an EDU whose cost burden is greatly affected by the performance of the RPS adjustment, MID looks forward to working with ARB staff to perfect the guidance documentation. (MODESTOID)

Response: This comment is out of scope of the second 15-day proposed changes to the Regulation.

C-3.3. Comment:

CARB can do more to ensure alignment between the Cap-and-Trade Program and the state's renewable portfolio standards (RPS) program. The RPS program and application of the RPS adjustment found in section 95852(b)(4) should not be inexorably linked with the discussion of EDU allowance allocations, but rather, be part of a broader discussion to facilitate a greater understanding of the interactions between these two very important programs. To that end, independent of the current regulatory amendments, M-S-R urges the Board to direct staff to work with stakeholders on revisions to the regulatory guidance documents addressing application of the RPS adjustment. CARB staff and stakeholders have had multiple discussions regarding the RPS adjustment over the course of this rulemaking proceeding. During that time, it has become clear that a common understanding of all of the elements could be more clearly articulated in the regulatory guidance that the agency provides on its Cap-and-Trade Program homepage. Since such guidance is not intended to alter the regulatory requirement, it can be prepared outside of a regulatory proceeding. At the same time, revising the current guidance consistent with the outcome of the various stakeholder discussions would go far to remove confusion on the part of both compliance entities and staff in application of the important RPS adjustment moving forward. (M-S-R)

Response: This comment is out of scope of the second 15-day proposed changes to the Regulation.

D. OFFSETS AND OFFSET PROGRAM IMPLEMENTATION

D-1. Availability and Usage of Offsets

Offset Supply

D-1.1. Comment:

OFFSETS ARE ESSENTIAL

CalChamber maintains its position that a robust offset program is a key cost containment mechanism. A robust supply of offsets are required in order to reduce program costs. Therefore, a consideration of offset protocols is encouraged. Expanding the allowable use of offsets is a sound policy choice. Numerous economic studies have shown, including CARB's own analysis, that offsets are the best market-based alternative to reduce costs and limit leakage. Expanded use of offsets is consistent with CARB's statutory obligation to achieve the maximum technologically feasible and cost effective GHG emissions reductions. Offsets are a proven and cost-effective means of meeting AB 32 compliance obligations. (CALCHAMBERCOMMERCE)

Response: The commenter suggests expanding the allowable use of offsets and states that "a consideration of offset protocols is encouraged"; ARB staff assumes the commenter is requesting ARB to adopt protocols for additional offset project types. ARB staff did not propose changes to the quantitative usage limit or propose additional offset protocols in this rulemaking. Therefore, this comment is outside the scope of the current rulemaking and does not require a response. However, ARB staff is committed to evaluating additional offset protocol types and increasing participation under the existing compliance offset protocols to ensure sufficient offset supply.

D-1.2. Comment:

In this ongoing dialogue, SMUD urges consideration of changes to the cost containment mechanisms in the Cap and Trade structure that would...

- Ensure that offsets can provide a significant brake on future price increases by examining methods to better include offsets, particularly those that provide benefits to disadvantaged communities, in the Cap and Trade market.

(SMUD)

Response: This comment regarding offset supply is outside the scope of the rulemaking; therefore, no response is required. However, ARB staff is committed to evaluating additional offset protocol types and increasing participation under the existing compliance offset protocols to ensure sufficient offset supply.

Quantitative Usage Limit

D-1.3. Comment:

TID Supports the Retention of Offset Credits in the Cap-and-Trade.

TID supports the retention of the Quantitative Usage Limits as currently constructed, as GHG Offset projects incentivize *real* emissions reductions, even though they may be outside of the California State boundaries. The Cap & Trade Program is now regional, and any change, cut, or redefining of GHG Offset eligibility would only serve to drive up compliance costs. In addition, offsets represent a valuable cost control feature that should be retained to minimize the risk of catastrophic carbon prices as the cap continues to decline. (TURLOCKID)

Response: ARB appreciates the commenter's support.

D-2. Opposition to Offsets

D-2.1. Comment:

Eliminate offsets. However, if this recommendation is not accepted and offsets are used, they must offset the emissions in the area where the emissions occur. Offsets must be in the state; do not allow out-of-state offsets. Actions and investments taken by industry to reduce emissions need to be reinvested in the communities where the emissions have occurred. Any benefits from greenhouse gas reduction measures must affect California first. In addition to California emissions, also consider activities that can reduce pollution coming from across the Mexican border, to reduce emissions in the border region. Do not pursue or include reducing emissions from deforestation and forest degradation (REDD) international offsets in the Scoping Plan. ARB should commit to evaluate the emissions impacts of offsets and free allowances in EJ communities, including if Cap-and-Trade is extended/chosen, and then publish this study and consult with the EJAC. (EJAC)

Response: Commenter proposes elimination of offsets, or offsets limited to in-state projects. Elimination of offsets is outside the scope of the rulemaking. No changes were proposed to sections 95972(c) or 95973(a)(3) regarding offset project locations in the second 15-day amendments; therefore, the comment related to offset project location does not require a response.

D-2.2. Comment:

Do not allow out-of-state forest offsets—offsets should apply to in-state urban forests. (EJAC)

Response: No changes were proposed to sections 95972(c) or 95973(a)(3) regarding offset project locations in the second 15-day amendments; therefore, this comment does not require a response. However, the Board has adopted a

Compliance Offset Protocol Urban Forest Projects which is eligible for use in California and throughout the U.S.

D-3. General Offsets

Forest Buffer Account

D-3.1. Comment:

PG&E supports the change in Section 95895 regarding the replacement of Forest Buffer Account offset credits. We concur that, instead of a default 50% buffer account credit replacement in the event of invalidation, the calculation of credits in the buffer account that need to be replaced be done on a project by project basis, based on the total percentage of buffer account credits that have been retired to compensate for reversals up to the date of the invalidation. (PG&E)

Response: ARB appreciates the support.

D-3.2. Comment:

Support for the Proposed Change in §95985(i)(3)

Bluesource supports the change from an arbitrary 50% to a proportional and accurate amount of buffer account credits required to be replaced in this particular case of an invalidation. This approach ensures the integrity of the buffer pool, the primary goal, and is consistent with the previous “15-day” change to §95985(h)(3). (BLUESOURCE)

Response: ARB appreciates the support.

Miscellaneous

D-3.3. Comment:

Add AB 197 and SB 350 as a Known Commitments for this sector (EJAC)

Response: This comment does not address the proposed amendments to the Cap-and-Trade Regulation; therefore, this comment is outside the scope of the rulemaking and does not require a response.

D-3.4. Comment:

95792(c) Offset Use Restrictions

ARB’s proposal to expressly limit issuance of ARB offset credits to projects located in the United states or United States territories is based on the rationale that this clarification merely reflects the current protocol development process. ARB’s current position contradicts its prior policy decision to expand the geographic scope of the program to allow for future use of offsets from North America subject to the requirements of specific protocols. It is not a clarification. Rather is signals a wholesale reversal of California’s offset program policy. This limitation also serves as a deterrent

to other jurisdictions seeking to participate in the California market. It is inconsistent with the reality that GHG emissions reduction is a problem to be solved at a global, not a local level and is especially counterproductive in light of California's ongoing efforts to expand program linkages with Canadian provinces. (CIOMA)

Response: No changes were proposed to sections 95972(c) or 95973(a)(3) regarding offset project locations in the second 15-day amendments; therefore, this comment does not require a response.

D-3.5. Comment:

Request for Parody between Offset Project Types in §95973(b) (1) and (2)

In a recent "15-day" package of proposed amendments, Bluesource supported ARB's proposed change to limit the period for which a livestock, MMC or ODS project would be ineligible to receive offset credits for being out of regulatory compliance to the precise time period during which the project was actually out of compliance, as opposed to the entire Reporting Period. The exclusion of offset projects using the other protocols (forestry, urban forestry and rice cultivation), however, creates an unfair disadvantage for these projects as the consequences of invalidation would vary from project type to project type. Excluding these project types from these amendments is inconsistent with the other regulatory changes that have prioritized parity between offset types, so as not to unfairly advantage one over another.

While a prior Statement of Reasons document stated that "Other project types cannot be included in this proposal because there is no quantification mechanism within the applicable protocols to identify and remove crediting of partial Reporting Periods," we adamantly disagree with this conclusion since credits associated with a particular period of non-compliance could be readily and accurately calculated from forestry projects. By way of example, this very task has been accomplished under the forest carbon protocol developed by the Climate Action Reserve, upon which the ARB protocol was predominantly based. More broadly, if a forestry project was found to be out of regulatory compliance, the carbon sequestration represented in the forest growth and the wood products generated (if any) during the period of non-compliance could be subtracted from the reporting period. This can be accomplished to a high degree of accuracy by accounting for the precise growth and harvesting activities that took place during the period of non-compliance. Given this ability to quantify and remove crediting of partial Reporting Periods for forest projects, and ARB's general policy that all offset project types should be given the same regulatory treatment wherever possible, we believe forestry projects should be included with livestock, MMC and ODS in the amendment to the regulatory compliance rule.

This would be a very simple regulatory change with two options for textual changes:

Option 1: To include only forest carbon projects in this important regulatory update:

the phrase in §95973(b)(1) that reads, “An offset project using a protocol from sections 95973(a)(2)(C)1., 2., or 5. ...” should be changed to read, “An offset project using a protocol from sections 95973(a)(2)(C)1., 2., 4. or 5. ...”, and,

the phrase in §95973(b)(2) that reads, “An offset project using a protocol from sections 95973(a)(2)(C)3., 4., or 6. ...” should be changed to read, “An offset project using a protocol from sections 95973(a)(2)(C)3. or 6. ...”

Option 2: To include all project types in this important regulatory update:

the phrase in §95973(b)(1) that reads, “An offset project using a protocol from sections 95973(a)(2)(C)1., 2., or 5. ...” should be changed to read, “An offset project using a protocol from sections 95973(a)(2)(C)1. through 95973(a)(2)(C)6. ...”, and,

Eliminate §95973(b)(2) entirely.

It should also be noted that any claims of start and end dates or calculations of affected Offset Credits during a period of noncompliance would need to be “to the satisfaction of ARB,” similar to this same requirement in Section 95973(b)(1). (BLUESOURCE)

Response: This commenter requests “parity” (ARB staff assume Commenter means “parity”) between sections 95973(b)(1) and (b)(2). The proposed language in section 95973(b)(1) would allow for certain offset project types to be considered out of regulatory compliance for only part of a reporting period, so that the project may still receive offset credits for the part of the reporting period for which the project was in regulatory compliance. Under the proposed language in section 95973(b)(2), the remainder of offset project types would continue to not be eligible to receive offset credits for the entire reporting period if the project is not in compliance with regulatory requirements at any point during the reporting period.

No changes were proposed to section 95973 in the second 15-day amendments; therefore, this comment does not require a response. However, see also response to 45-day comment E-8.4 and response to first 15-day comment E-4.1.

D-4. Regulatory Compliance

D-4.1. Comment:

95973(b) Offset Invalidation

In this section, ARB is bestowing itself with unlimited discretionary power regarding a project’s regulatory compliance status. The proposed language states an enforcement action “is not the only consideration ARB may use in determining whether a project is out of regulatory compliance.” The loose language will allow ARB to reward and punish projects using indeterminate factors. Not only can a project be deemed out of compliance with no official action but ARB may use unknown elements to decide if a project is in regulatory compliance despite enforcement actions.

CIOMA asks that ARB make further changes to this section to specify that offset credits will not be invalidated if the primary regulatory body (e.g., EPA, OSHA, etc.) does not issue a violation pertaining to the offset project. At a minimum, the open-ended language should be removed. (CIOMA)

Response: This comment refers to proposed 45-day language in section 95973(b). No further changes were made to section 95973(b) in the 15-day amendments. Therefore, this comment does not require a response. However, ARB staff responded to similar comments received during the 45-day comment period. See response to 45-day comment E-8.2.

D-4.2. Comment:

Offset Credit Invalidation

AB 32 requires that offsets used for compliance purposes must be real, permanent, quantifiable, verifiable, and enforceable. The Cap-and-Trade Regulation provides a mechanism for invalidating previously issued offset credits if an offset project is not in "regulatory compliance." Cap-and-Trade Regulation § 95973(b). The language of the provision is unclear and this ambiguity has created significant uncertainty among Offset Project Operators and Authorized Project Designees, along with covered entities who use offsets to meet their compliance obligation.

In the current rulemaking, the Board is proposing to amend § 95973(b) with the addition of new paragraphs (1), (2), (3) that provide additional detail as to the period of time an offset project would be considered to be out of compliance for purposes of invalidating offset credits. SCI supports the proposed amendments which provide necessary clarification and certainty to Offset Project Operators and Authorized Project Designees. However, SCI would encourage the Board to expand the evidence an Offset Project Operator could provide to demonstrate the start and end date of any regulatory non-compliance.

Proposed Amendment to § 95973(b)(1)(A). With respect to the beginning date the Board will consider an offset project out of compliance, proposed § 95973(b)(1)(A) states that an offset project would be considered out of compliance either based on the date of the last inspection that did not show regulatory non-compliance or documentation from a local, state or federal regulator that "identifies the precise state date" of non-compliance with supporting evidence.

Given the need to provide evidence showing the date an offset project went out of compliance, the need for documentation from the relevant local, state or federal regulatory oversight body is duplicative and potentially problematic. The relevant local, state or federal regulatory oversight bodies, like the Board and the Board's staff, have tremendous workloads and very limited resources to fulfill their many varied statutory obligations. SCI can foresee a situation where it is very difficult, if not impossible, for an Offset Project Operator or an Authorized Project Designee to secure the required

documentation from the relevant local, state or federal regulatory oversight body thereby requiring that the start date be considered the last inspection or start of the reporting period -either of which may be grossly inappropriate.

Accordingly, SCI would propose that the Board allow an Offset Project Operator or an Authorized Project Designee to provide *either* a letter from a regulatory oversight body specifying the start date *or*, alternatively, evidence that indicates the date when the offset project went out of compliance (CEMS or other monitoring data, engineering estimates, satellite imagery, witness statements or other reasonable method). This could be accomplished by splitting § 95973(b)(1)(A)1. into two separate subparagraphs and adding an "or" so it would read as follows:

1. A letter ~~Documentation~~ from the relevant local, state, or federal regulatory oversight body that expressly identifies the precise start date of the offset project being out of compliance; or

2. ~~Documentation must include~~ Evidence of the start date such as CEMS or other monitoring data, engineering estimates, satellite imagery, witness statements, or other reasonable method to aid in the identification of the precise start date; or

Proposed Amendment to § 95973(b)(1)(B). Similarly, with respect to the end date of any regulatory non-compliance, proposed § 95973(b)(1)(B) requires documentation from the relevant regulatory oversight body showing the offset project is deemed to have returned to regulatory compliance or, in the absence of such documentation, the end of the reporting period will be considered the end of non-compliance. The Board should not impose this affirmative obligation on other regulatory bodies. Rather, SCI would propose that the Board accept other indicia that an offset project has returned to regulatory compliance. This evidence could include the data, information or certification filed by the Offset Project Operator or Authorized Project Designee at the relevant regulatory oversight body attesting that the offset project has returned to regulatory compliance or a written determination by the oversight body of compliance. SCI would recommend that § 95973(b)(1)(B) be amended to read as follows:

“(B) For determining the end date when the offset project returned to regulatory compliance, the Offset Project Operator or Authorized Project Designee must provide documentation ~~from the relevant local, state, or federal regulatory oversight body stating~~ demonstrating that the offset project is back in regulatory compliance. This documentation can include a copy of the data, information, or certification the Offset Project Operator or Authorized Project Designee is required to provide to the relevant local, state, or federal regulatory oversight body in order for the oversight body to conclude the offset project is in regulatory compliance or a written determination by the oversight body as to the date when the offset project returned to regulatory compliance. ~~The date when the offset project is deemed to have returned to regulatory compliance is the date that the relevant local, state, or federal regulatory oversight body determines that the project is back in regulatory compliance. This date is not necessarily the date~~

~~that the activity ends or the device is repaired, as may include time for the payment of fines or completion of any additional requirements placed on the offset project by the regulatory oversight body, as determined by the regulatory oversight body. If the relevant regulatory oversight body does not provide a written determination regarding the date when the project returned to regulatory compliance to the satisfaction of ARB, then~~ In the absence of such documentation or written determination, for purposes of the applicable Reporting Period, the Offset Project Operator or Authorized Project Designee must use the end of the Reporting Period for the end date when the offset project returned to regulatory compliance.”

The Board should have confidence that the local, state or federal regulator over the offset project would exercise their enforcement authority if an Offset Project Operator or Authorized Project Designee files wrong or inaccurate data or information or fraudulently certifies that an offset project is in compliance. The Board can therefore rely on that data, information or certification for its purposes of establishing an end date for regulatory non-compliance.

Moreover, the Board has its own enforcement authorities to go after an Offset Project Operator or Authorized Project Designee who misleads them with respect to the beginning or end date for a period of non-compliance. The Board's enforcement power is in addition to that of the local, state or federal regulator of the offset project. Pursuant to the Subarticle 15 (Enforcement and Penalties), an Offset Project Operator or Authorized Project Designee has consented to the jurisdiction of the Board. At the same time, as a voluntarily associated entity, the Executive Officer may "suspend, revoke or place restrictions" on the Holding Account of an Offset Project Operator or Authorized Project Designee. SCI believes the Board's separate enforcement authority further ensures that an Offset Project Operator or Authorized Project Designee will accurately represent to the Board the commencement and end dates of any period of regulatory non-compliance for an offset project. (SOLVAY)

Response: This comment refers to the proposed language in 95973(b), 95973(b)1 and its subsections. No changes were made to these sections in the second 15-day amendments; therefore, this comment does not require a response. However, ARB staff responded to several similar comments received during the 45-day and first 15-day comment periods, as in responses to 45-day comments E-8.2 and E-8.3, and response to first 15-day comment E-4.4.

E. AUCTION AND TRADING REQUIREMENTS

E-1. Other Program Requirements

Holding Limits

E-1.1. Comment:

The April 2017 changes to Section 95920 regarding the limited exemption from the holding limit (limited exemption) represent a significant departure from the previous

calculation method. Under the current regulation, calculation of the limited exemption is rooted in emissions from base years at the start of the Cap-and-Trade Program. Many entities in the electric sector have significantly reduced their emissions since those base years, in line with California's GHG reduction policies like the RPS. The new methodology which relies on emissions from more recent years will likely result in a decreased limited exemption for some entities that have made progress toward reducing their emissions.

PG&E has consistently advocated that covered entities with large obligations should be provided additional flexibility to engage in legitimate hedging activities and/or plan for post-2020 compliance. ARB's modifications to Section 95920 frustrate this goal. ARB should provide an opportunity for compliance entities that may need to rebalance their portfolios given the more restrictive limited exemption calculation to receive an exemption from the newer, lower limit. Compliance entities developed portfolio management strategies consistent with the current regulation and should not be subject to holding limits violations due to new regulatory changes. Accordingly, PG&E recommends that ARB provide covered entities an exemption from the new effectively lower holding limit so that covered entities may reallocate existing portfolios in line with the proposed changes. (PG&E)

Response: Staff disagrees with the first part of the comment, that entities with decreasing emissions obligations are harmed by the new calculation procedure. The intent of the exemption since the initial development of the Regulation, and as described in the ISOR of this rulemaking, has been to allow entities with any sized emissions obligations to accumulate the allowances they need for compliance. If an entity's emissions are trending downward, then a decreasing limited exemption does not compromise this objective. It was never staff's intent to "grandfather" an entity's earliest emissions into the limited exemption. In fact, as described in the ISOR for this rulemaking, the limited exemption has always indicated that an entity that has been an emitter throughout a compliance period to enter the third year of a compliance period with a limited exemption equal to several years' worth of emissions. This would allow the entity to include within its limited exemption the allowances accumulated for the first two years of the compliance period as well as the allowances it would accumulate in 2017 for the third year of the compliance period. The new text in the 45-day amendments maintains this approach. The first and second 15-day modifications further clarify the language to ensure clear understanding and implementation.

Staff disagrees with the second part of the comment, since an entity that faces a large or growing emissions obligation will obtain a larger limited exemption. As such, ARB staff declines to make the changes requested by the commenter.

E-1.2. Comment:

Tesoro disagrees with CARB's proposed revision to the limited exemption calculation in 95920(d)(2)(F). The proposal will substantially reduce our ability to manage the allowances needed for compliance and current compliance flexibility found in the regulation. We specifically oppose the reduction in the limited exemption by the amount of allowances that are required to be surrendered when an annual compliance obligation is due. We understand that CARB has proposed this in order to provide some 'equivalency' to linked programs in Canada, but the Canadian provinces do not have an annual surrender obligation so there is no need for CARB to reduce our compliance flexibility based on the approach in Canada. That is to say that the Canada requirements for surrender of obligations are already different than those in California; therefore, there is no need for equivalency in the amount of the limited exemption. This recent proposed change, when added to existing restrictive holding limits, just makes compliance more difficult for entities with large compliance obligations and adds no program environmental benefit. (TESORO)

Response: As the commenter indicates, one reason for the adjustment following the annual surrender event relates to consistency with linked partner jurisdictions. When a California entity complies with an annual surrender event, its remaining compliance period obligation is reduced but its limited exemption is not. This allows the California entity to accumulate allowances in its compliance account above its remaining compliance period obligation in a way the Québec entity cannot. The proposed text removes this disparity. ARB staff believes these changes are necessary, while still maintaining the intention of the limited exemption. See response to second 15-day comment E-1.1.

E-1.3. Comment:

ARB Proposed Amendments to the Limited Exemption Provision

ARB proposes revisions to the Cap-and-Trade Regulation provisions specifying the holding account limit limited exemption. LADWP supports ARB's efforts to update the limited exemption regulatory provisions in order to harmonize with the exemption used in linked markets without annual compliance obligations. However, LADWP is concerned that the proposed changes introduce uncertainty and may unintentionally result in significant adverse changes to the calculated limited exemption for covered entities.

Section 95920(d)(2)(B)

ARB has proposed changes to section 95920(d)(2)(B) in an effort to "clarify the process for initially calculating the limited exemption." In the second 15-day notice, ARB suggests that the intent of section 95920(d)(2)(B) as amended is similar to the purpose of the section under the current regulations: to establish a baseline limited exemption for

registered entities.⁹⁰² However, LADWP is concerned that the proposed amendments to section 95920(d)(2)(B) introduce new uncertainty.

First, whereas the current regulatory text and the proposed 45-day amendment is clear that this section applies only for a limited period of time by specifying the dates for which it applies, ARB's current proposal does not. The proposed section makes clear that it applies to entities that have registered as of January 1, 2017, but does not appear to contain any text that limits its application to the calculation of the limited exemption as of a particular date. In particular, by stating that the limited exemption "is the sum" of a formula whose values can change over time ("most recent," "now," and "oldest"), the proposed text suggests this section is intended to determine the limited exemption at all times and is not only intended to set the initial or baseline conditions of the exemption. LADWP does not believe that ARB intends for section 95920(d)(2)(B) to be used to set the size of an entity's limited exemption throughout all compliance periods, and requests that ARB revise the provision to better reflect the intended scope of application of that section.

Second, LADWP requests that ARB further clarify which emissions reports can be used to form the basis of the initial limited exemption under the revised Cap-and-Trade Regulation. ARB's proposed language is that the relevant emissions are those "emissions contained in the most recent annual emissions data reports . . . for which the entity now has a compliance obligation plus the amount of emissions in the oldest emissions report for which the entity now has a compliance obligation." However, the "most recent" and "oldest" compliance reports will depend on the time of year at which an entity calculates its baseline limited exemption, before or after September 1st when the prior year's emission reports have been submitted and verified. Even with a specified date by which the baseline limited exemption is calculated, this section results in multiple potential meanings. By using the plural "reports" in the first clause, this provision could be read to include all emissions for which an entity has a compliance obligation for the compliance period as of the applicability date for this section (e.g., if the applicability date is September 1, 2017, an entity's 2015 and 2016 emissions). In the alternative, this provision could be read to include only the most recent report (i.e., if the applicability date is September 1, 2017, 2016 emissions). Further specification, and in particular reference to emissions specific from reporting years, would help clarify this provision.

Finally, LADWP requests that ARB further clarify the proposed text "less the amount of any annual compliance obligations already due in the current compliance period." As discussed above, what emissions are "already due" will depend on whether the baseline limited exemption is calculated before or after September 1st and before or after November 2nd (when annual allowances should have been surrendered). In addition, "already due" could refer to compliance obligations that have accrued but for which

⁹⁰² Second Notice of Public Availability at 16 ("Section 95920(d)(2)(B) is modified to further clarify the process for *initially* calculating the limited exemption from the holding limit")(emphasis added).

allowances need not be surrendered until the end of the compliance period. Or "already due" could refer to compliance obligations that were already required to have been surrendered (i.e., for annual compliance obligations, 30 percent of emissions from the previous data year).

Section 95920(d)(2)(F)

Comparison between the current regulation, the 45-day amendment, and the second 15-day amendment indicates that the adoption of the second 15-day amendment will result in an overall reduction of the limited exemption during years without compliance period obligations. Under current regulation, an entity's limited exemption is not reduced when the entity surrenders allowances to cover its annual compliance obligation. However, under section 95920(d)(2)(F), as amended by the second 15-day amendment, the limited exemption for covered entities could be significantly reduced depending on whether it is the beginning or the end of a compliance period. LADWP urges ARB to abandon this proposed change. ARB has not provided an explanation for why this change is necessary. This change will reduce the flexibility by which compliance entities manage their supply of allowances. (LADWP)

Response: LADWP is correct in its first view of section 95920(d)(2)(B), that it sets the initial value of the limited exemption for entities already registered as of January 1, 2017 at that point in time and not for the whole compliance period. Note that section 95920(d)(2)(C) sets the initial value of the limited exemption for entities registering after January 1, 2017. After setting the initial value, the limited exemption is increased each year by the amount of the covered emissions reported for the previous year (section 95920(d)(2)(D).) Proposed section 95920(d)(2)(F) would then reduce the limited exemption by the amount of emissions contained in the emissions reports reflecting the number of years for which a compliance obligation was due that calendar year, starting with the oldest emissions report used to calculate the limited exemption.

In this way the limited exemption is converted into a moving sum that over time will reflect trends in an entity's emissions. In the existing calculation, the limited exemption is tied to older emissions reports. Thus, in the existing system, an entity whose emissions have decreased has a larger exemption than it needs and an entity whose emissions have increased has an exemption that is too small.

On LADWP's second point, the number of reports used to calculate the initial value of the limited exemption will depend on how long the entity has been covered. Staff will calculate the initial value based on the most recent reports as of the January 1, 2017 start date.

On LADWP's final point, the interpretation of "already due" as "already required to have been surrendered" is correct. This language is necessary because the limited exemption will reflect scheduled surrender compliance, and not excess

emissions obligations calculated when an entity does not meet its timely surrender obligations.

Staff intends to revise the online guidance to provide stakeholders with detailed calculations procedures to help illustrate how the amended language works. Also, CITSS will reflect the modified calculation as of the effective date of the regulation.

Corporate Associations

E-1.4. Comment:

TID Is Opposed to the Proposed Amendments to Consultant and Advisor Registration.

As amended, Section 95833(a)(6) would create a “Direct Corporate Association” between two entities if either one of the entities fails to disclose a consultant or advisor that it shares with the other entity. TID is concerned that this new provision was not vetted among stakeholders prior to the release of the 15-day amendment language, and it is not clear from the notice or the regulations why this amendment is needed. We do not believe this provision will further the ARB’s role in serving as a market monitor or protect the Program from manipulation. The provision would unfairly penalize a company that is in compliance when another un-associated entity fails to fulfill its compliance obligations under Section 95923. The entity that is penalized has no control over another entity’s compliance with the program. There is no rational basis for this provision and we are concerned that the proposed amendment would penalize regulated entities that contract with consultants and advisors. We believe this proposed amendment would interfere with a regulated entity’s ability to contract with consultants and advisors. For these reasons, the ARB should not amend the regulation as contemplated in Section 95833(a)(6). (TURLOCKID)

Response: The proposed text restores the requirements that were removed from the existing regulation in section 95833(f)(7) during the 45-Day amendments.

Staff understands the commenter’s concerns but would like to clarify that the proposed changes in the second 15-Day Modifications are not new, but rather maintain the existing requirements of section 95833(f)(7). Staff does not believe there is an unfair penalty for entities that contract with consultants or advisors, and disagrees that the proposal to keep the existing requirement interferes with the ability of entities to contract with consultants or advisors. Since the requirement came into effect in 2014, a number of Cap-and-Trade Consultants and Advisors have been retained by registered entities and properly disclosed to ARB pursuant to section 95923. Without the proposal to keep the existing requirement, ARB staff view these individuals who can use an entity’s market information without restriction as a real concern from a market manipulation perspective. As stated in the 2013 Final Statement of Reasons, staff believes the requirement to disclose consultants and advisors is necessary for proper

market oversight to ensure holding and purchase limits are split between entities that can be controlled by one individual.

Miscellaneous

E-1.5. Multiple Comments:

95832(F)(2) Account Representative

The proposed change requires ARB to review and approve any change an entity makes to their account representation. This will increase the complexity of compliance and cause delays, as well as increasing operating costs and difficulties for both ARB and participating entities.

CIOMA asks that ARB provide the rationale behind the need for this change and perform analysis on the effects this change will have on the staff's workload and any projected need for additional staff or funding. (CIOMA)

Comment:

Account Representation

The proposed change requires ARB to review and approve any change an entity makes to their account representation. This will increase the complexity of compliance and cause delays, as well as increasing operating costs and difficulties for both ARB and participating entities.

CCPC asks that ARB provide the rationale behind the need for this change and perform analysis on the effects this change will have on the staff's workload and any projected need for additional staff or funding. (CCPC)

Comment:

ACCOUNT REPRESENTATION

The proposed change requires CARB to review and approve any change an entity makes to their account representation. It is unclear why this change is necessary as it will increase the complexity of compliance and cause delays, as well as increase operating costs and difficulties for both CARB and participating entities.
(CALCHAMBERCOMMERCE)

Response: ARB Staff appreciates the comments concerning how changes made in an entity account representation must be approved by the accounts administrator. To ensure the information submitted meets program requirements, changes made in an entity's account representation have always required ARB review and approval of the required documentation before the changes become effective. The proposed modification in section 95832(f)(2) referenced in the comments intends to clarify an existing administrative process; it is not a new requirement.

E-1.6. Comment:

Additionally, any entity-specific allowances remaining from the previous compliance periods should be available for use in post 2020. (SOLARTURBINES)

Response: The proposed amendments do not include any provisions to invalidate any allowances held by registered entities. Allowances remain valid until surrendered pursuant to section 95922(c).

F. GHG EMISSIONS BUDGET AND COST CONTAINMENT

F-1. GHG Emissions, Costs, and Other Priorities

F-1.1. Comment:

Regarding the impacts of GHG emissions trading on disadvantaged communities

Some have concluded that, under California's GHG cap-and-trade program, program benefits are being exported while GHG emissions increase in disadvantaged (EJ) communities. The analysis of Cushing, et al.⁹⁰³, has been advanced as evidence to this effect. As Meredith Fowlie discussed in an October 10, 2016 blog⁹⁰⁴, we do not think that conclusions about the impacts of GHG emissions trading on local pollution in EJ communities can be drawn from this study.

Cushing et al. compare GHG emissions at regulated facilities during the first two years of the program (2013-2014) against emissions at those same facilities in the years preceding (2011-2012). The researchers document increases in emissions in some sectors (and reductions in others) over this time period. The authors themselves emphasize the preliminary nature of the analysis. We further note that these pre-post comparisons can confuse the effects of a policy with the effects of other factors that are changing over time. For example, the electricity sector is one of the sectors where researchers document a small increase in GHG emissions over the pre- and post-policy period. The San Onofre nuclear plant in early 2012 was a major driver of this observed increase. It would be wrong to attribute any emissions implications of this plant closure to GHG emissions trading.

The Cushing et al. report highlights trends in in-state GHG emissions and the use of offsets, which warrant further investigation. But it does not provide a basis for concluding that EJ communities have been harmed under GHG emissions trading. A

⁹⁰³ Lara J. Cushing, Madeline Wander, Rachel Morello-Frosch, Manuel Pastor, Allen Zhu, and James Sadd, "A Preliminary Environmental Equity Assessment Of California's Cap-and-Trade Program" http://dornsife.usc.edu/assets/sites/242/docs/Climate_Equity_Brief_CA_Cap_and_Trade_Sept2016_FIN_AL2.pdf

⁹⁰⁴ Meredith Fowlie, "Is cap and trade failing our low income and minority communities?" Energy Institute at Haas Blog, October 10, 2016. <https://energyathaas.wordpress.com/2016/10/10/is-cap-and-trade-failing-low-income-and-minority-communities/>

recent analysis⁹⁰⁵ by Kyle Meng examining emissions trends during the first years of the cap-and-trade program, using the same GHG data source, suggests that, if anything, GHG emissions declines have been slightly greater in EJ areas, though that the difference is not statistically significant.

Addressing concerns about local pollution exposures in disadvantaged communities must be part of the larger policy discussion. However, attempting to regulate global and local pollution with the same regulation will result in a policy that does neither job well. Concerns about local pollution do not provide a reason to abandon cap and trade in favor of more prescriptive regulations. Market-based regulation of greenhouse gas emissions can be used to coordinate a cost-effective response to climate change, while generating revenues that can be used to support local air quality improvements. (BORENSTEIN)

Response: Thank you for your comment. See also response to 45-day comment K-1.5.

F-1.2. Comment:

The price of carbon must be increased, with the resulting funds invested in local communities to ensure all benefits from a greenhouse gas free future. (EJAC)

Response: This comment appears to have been submitted with reference to the proposed 2017 Scoping Plan Update, and is therefore outside of the scope of this rulemaking.

F-1.3. Comment:

Cost Containment. ARB staff should quickly evaluate possible options for implementing cost containment provisions. The ARB Board previously directed ARB staff to develop a cost containment mechanism as part of the Program. SPCPA strongly urges ARB to promptly engage stakeholders in discussions on designing, testing, and implementing a credible and enforceable cost containment mechanism. Establishing such a mechanism now, while the market is relatively stable, would establish the appropriate infrastructure and prove more effective than making reactionary policy changes if abatement costs escalate due to market fluctuations or a market crisis occurs. Having a clear and transparently-developed cost containment measure would provide regulated entities with the information and the confidence necessary to make policy decisions and prioritize investments in the appropriate areas. (SCPPA)

Response: The commenter requests the immediate development of a cost-containment mechanism pursuant to a Board resolution. Staff notes that the program already includes multiple cost-containment features, including the use of offsets, multi-year compliance periods, and a strategic reserve. As such, staff

⁹⁰⁵ Kyle Meng, "Is cap-and-trade causing more greenhouse gas emissions in disadvantaged communities?", April 2017. https://www.dropbox.com/s/ka0a884oxkotxhj/Meng_CT_EJ.pdf?dl=1.

has implemented the Board directive and is open to reviewing and considering adjustments to the regulation as needed in the future.

F-1.4. Comment:

CIOMA represents about 300 members, including 90 percent of all independent petroleum marketers in California and one-quarter of the state's 12,000 convenience stores and services stations. Almost all of the businesses represented by CIOMA are small family-owned and minority-owned businesses. We should not be confused with the refiners that manufacture the petroleum products for the west. CIOMA members are in the service business to meet market demand through providing services to procure, transport, and retail sell fuel.

CIOMA didn't take an official position on this recent legislation and actions with the legislature regarding the Cap-and-Trade Program. I do want to convey that amongst the CIOMA members there is a legitimate concern and agitation about the Cap-and-Trade Program and the extension of its life. So while we did not intervene in the legislature, CIOMA members are going to be very engaged in the implementation of the program by CARB.

The details of how the Cap-and-Trade Program is directed, manipulated, and implemented will have a profound impact on CIOMA's members and our customers.

I hope that CARB will often consult CIOMA as a valuable resource to help determine the appropriate implementation of AB 398. CIOMA and myself are available to help ensure that all aspects of proposed rules are examined to ensure effective and equitable regulations. Our members offer unique and often underrepresented businesses perspectives that CARB staff can use to prevent harmful unintended consequences to small business and rather amplify the efficacy of these regulations. Since CIOMA members interact with the members of the public daily, we can provide insight into how regulations are affecting Californians at the pump and in their businesses.

Thank you for your time today, and please don't hesitate to reach out when you're considering any regulations or actions that will impact the fuel industry of California.
(CIOMA2)

Response: Since the commenter did not make a specific request regarding any regulatory amendments proposed in this rulemaking, no response is needed.

F-2. Auction Reserve Price

F-2.1. Comment:

In this ongoing dialogue, SMUD urges consideration of changes to the cost containment mechanisms in the Cap and Trade structure that would...

- Develop a hard price cap structure that provides market and political assurance of program continuation at reasonable prices while preserving the environmental integrity of the Cap and Trade program

(SMUD)

Response: See response to first 15-day comment H-3.1.

F-3. Disposition of Unsold and Consigned Allowances

Moving Unsold Allowances to the Allowance Price Containment Reserve

F-3.1. Comment:

95911(g) Disposition of Unsold Allowances

CIOMA opposes the proposal to transfer to the Allowance Price Containment Reserve (APCR) beginning January 1, 2018, any current vintage allowances that remain unsold for more than 24 months.

This unspecified volume would be added to any unsold volumes already in the APCR (currently 141 million tons) and added to the proposed forward stocking of approximately 54 million more allowances post-2020.

The existing APCR already contains large volume of allowances (nearly equal to the 2030 cap itself), and adding to it would only further reduce liquidity, increase uncertainty and risk of volatility for market participants and almost certainly increase future allowance cost for compliance entities. Since allowances are still available in the APCR to market participants, the most significant change is to increase the overall costs of allowances in the market by setting the price at \$60 above the floor, raising costs to compliance entities without allowing the market to operate cost-effectively.

ARB's proposed interference and step-change adjustments in the market, intended to take effect less than 12 months from now constitutes a dramatic change in the regulation. It would have the effect of raising market prices in the near term, perhaps for the purpose of increasing State revenue. Further, it would have the perverse effect of rewarding some companies and penalizing others for past business decisions. Program changes, and even proposals such as this, can damage the integrity of the Cap-and-Trade program and erode confidence in the market. ARB should seek to avoid policies and actions that interfere with the current market.

CIOMA continues to recommend that ARB analyze the potential for its APCR proposals to increase program costs and impact market liquidity, and allow more transparent public discussion of these issues through full 45-day notice and comment periods. Pending this review, CIOMA recommends that ARB should: 1) avoid making regulatory changes that would interfere with the operation of the market in the pre-2020 timeframe, and 2) continue to return unsold allowances to auction, which will moderate expected

market fluctuations without placing unreasonable new cost burdens on compliance entities. (CIOMA)

Response: Staff did not make changes to this section in the second 15-Day Modifications to the Regulation. Staff maintain the rationale for transferring unsold allowances to the APCR as explained in the response to the comments received in the 45-day comment period and first 15-Day comment period. See responses to 45-day comments H-3.2 and H-3.3.

F-3.2. Comment:

Consignment of unsold allowances to the Allowance Price Containment Reserve (APCR) should be delayed until such allowances remain unsold for much longer than eight consecutive auctions. In our January 20, 2017 comments regarding the first 15-day changes to the proposed Cap-and-Trade amendments, MID suggested that eight consecutive auctions, to be applied retroactively, is not sufficient time to wait before unsold allowances are sent to the APCR. The chilling effect caused by the Chamber of Commerce lawsuit challenging the legitimacy of the Cap-and-Trade program created an environment that destabilizes the operation of the program and any changes to its cost containment provisions in response to such an environment would be premature and detrimental to the program once the cap has declined sufficiently to induce intense competition for allowances. Since the ruling in favor of the Cap-and-Trade program, allowance prices on the secondary market have rebounded and maintained a value higher than the auction floor price. It would be prudent to provide more time to evaluate market performance before eroding the cost containment value of the pool of unsold allowances. (MODESTOID)

Response: Staff did not make changes to this section in the second 15-Day Modifications to the Regulation. Staff maintain the rationale for transferring unsold allowances to the APCR as explained in the response to the comments received in the 45-day comment period and first 15-Day comment period. See responses to 45-day comments H-3.2 and H-3.3, and response to first 15-day comment H-2.1.

F-4. Allowance Price Containment Reserve (APCR)

Price Tiers

F-4.1. Comment:

PG&E supports ARB's proposed modification regarding the calculation of the 2021 APCR value; we agree that calculating the fixed dollar amount in 2020 rather than establishing its dollar value in this rulemaking provides certainty in the cost of APCR allowances.

However, establishing the fixed dollar amount based on the 3rd tier of the 2020 APCR results in too high a fixed increment and too high a post-2020 APCR price to provide

sustainable cost containment. This issue is increasingly important as the rate of cap decline doubles post-2020 to achieve deeper reductions. In order to provide more meaningful cost-containment in the post-2020 program, PG&E encourages ARB to consider a lower fixed dollar amount above the floor price; specifically, we encourage ARB to adopt a fixed dollar amount tied to the 1st tier of the APCR instead of the 3rd tier APCR.

In addition to providing more effective cost-containment, a smaller step between the auction floor price and the APCR price reduces the incentive to manipulate the market to raise prices. (PG&E)

Response: Staff appreciates the commenter's support for the proposed modifications to calculate the 2021 APCR value. See responses to 45-day comments H-4.5 and H-4.6.

F-4.2. Comment:

ARB should use the lowest Allowance Price Containment Reserve (APCR) price tier in 2020 as the foundation for the revised APCR structure.⁹⁰⁶ SCE agrees with other utilities that suggest ARB should use the current lowest tier of the ARCR as the foundation for the post-2020 design of this important cost containment mechanism. Removing access to a supply of additional allowances at lower prices in the presence of a price spike can have the effect of raising compliance costs at the precise moment we should be attempting to contain them. (SOCALEDISON)

Response: See responses to 45-day comments H-4.5 and H-4.6.

F-4.3. Comment:

Section 95913. Sale of Allowances from the Allowance Price Containment Reserve

CCEEB appreciates the proposed modification to the method of calculating the 2021 APCR value. Calculating the fixed dollar amount in 2020 rather than establishing its dollar value in this rulemaking reduces inflation uncertainty.

However, establishing the fixed dollar amount based on the 3rd tier of the 2020 APCR results in too high a fixed increment and too high a post-2020 APCR price to provide sustainable cost containment. This issue is increasingly important as the rate of cap decline doubles post-2020 to achieve deeper reductions. In order to provide more meaningful cost-containment in the post2020 program, CCEEB encourages ARB to consider a lower fixed dollar amount above the floor price. Specifically, CCEEB encourages ARB to adopt a fixed dollar amount tied to the 1st tier of the APCR instead of the 3rd tier APCR.

In addition to providing more effective cost-containment, a smaller step between the auction floor price and the APCR price reduces incentive to manipulate the market to

⁹⁰⁶ Section 95913

raise prices. In this way, the floor and APCR prices function similarly to a price “collar” on allowances. (CCEEB)

Response: See responses to 45-day comments H-4.5 and H-4.6. On the commenter’s recommendation to include smaller steps between the floor price and the APCR price, staff has also provided a response already to this comment. See the response to first 15-day comment H-3.3 received for the first 15-Day Modifications.

F-4.4. Comment:

We look forward to engaging with staff and the Board during the next regulatory phase, which will be needed to implement the direction provided in AB 398 to further strengthen the post 2020 program. As we do so, we hope the Board and staff will consider all options for maintaining a stringent cap that will ensure California is able to reach the ambitious climate goals set into law. These include setting a price ceiling that is sufficiently high to ensure the environmental integrity of the program. (EDF2)

Response: Thank you for the support. To the extent the commenter references future rulemakings, those comments are outside the scope of the current rulemaking and no further response is needed.

Miscellaneous

F-4.5. Comment:

The proposed revisions to section 95913(k)(2)(A) recognize the potential for differences between price projections and actual future values. NCPA supports this further proposed revision and encourages CARB to apply this same rationale to the overall concept of cost containment, and ensure that robust and meaningful cost-containment is part of the program design. It is important to protect compliance entities – as well as their customers – from extreme price spikes or other unanticipated market conditions that would impact compliance costs in the future. (NCPA)

Response: Staff appreciate the commenter’s support for revising the process to determine the reserve sale price beginning 2021.

F-4.6. Comment:

Cost-Containment in the Post-2020 Cap and Trade Program

SMUD remains concerned about long-term cost containment in the Cap and Trade structure. The Cap and Trade marketplace is relatively inelastic in both supply and demand, and prices can quickly escalate to market-busting levels when demand is expected to strain supply. SMUD looks forward to continued dialogue with stakeholders and ARB staff as the Cap and Trade program is extended. In this ongoing dialogue, SMUD urges consideration of changes to the cost containment mechanisms in the Cap and Trade structure that would:

- keep unsold ARB allowances in the basic Cap and Trade market (while removed from current vintages) rather than shifting them to the significantly higher priced APCR structure;
- Include “speed bumps” to slow or stop market price increases prior to accessing the APCR...

(SMUD)

Response: Staff did not make changes to this section in the second 15-Day Modifications to the Regulation. Staff has addressed the commenter’s concerns for creating a mechanism to move unsold allowances to the APCR in the response to multiple comments received during the 45-Day Comment Period. See response to H-3.2. On the commenter’s recommendation to include “speed bumps,” staff has also provided a response already to this comment. See the response to first 15-day comment H-3.3.

F-4.7. Comment:

MARKET REFORMS ARE NECESSARY

In order to ensure market stability and cost-containment, there need to be reforms made to the Allowance Price Containment Reserve (APCR). Post-2020 emissions reductions will constrain the market as the cap declines at a more rapid rate. Price containment in the APCR is necessary if the reserve is to be a true cost-containment mechanism. We recommend that there be further consultation with market experts in order to make necessary reforms to ensure the stability of the market and maximize cost-containment. (CALCHAMBERCOMMERCE)

Response: Staff will continue to discuss cost containment with market experts and stakeholders. Staff also believes that in the case of an increase in demand for allowances that the provisions adopted in the prior two rulemakings to allow replenishment of the Reserve will be effective until any underlying market issues are resolved.

F-4.8. Comment:

Section 95913(d)(1)(A) Frequency of Reserve Sales

CIOMA opposes the proposed changes affecting the Reserve sales schedule starting in 2021. ARB is proposing changes that will increase the occurrences of attempted market manipulation. It is shortsighted and a seemingly incorrect assumption to base the criteria of future Reserve sales on past interest, especially as the cap is adjusted. We encourage ARB to continue to base the availability of Reserve sales on the current criteria, regardless of current and past interest in the quarterly Reserve sales. (CIOMA)

Response: Staff did not make changes to the frequency of reserve sales in the second 15-Day Modifications to the Regulation. Instead, the proposed changes

were made to improve clarity of the section and to explicitly reference the auction settlement price.

However, staff would still like to clarify the commenter's understanding of the proposed changes. The proposed changes to the availability of reserve sales is not based on current or past interest in quarterly participation of reserve sales, but rather three of the reserve sales scheduled each year (first, second, and final reserve sale) would only be offered if the Current Auction held in the preceding quarter results in a settlement price greater than or equal to 60% of the lowest Reserve tier price. As explained in the Initial Statement of Reasons, staff believes that providing a market indication that will require Reserve sales to be held only in the quarters in which there is more likely demand (third reserve sale will be held as well as first, second, and final reserve sale if the demand for allowances results in a high enough settlement price) still meets the intent of the cost containment elements of the Regulation while providing resource efficiencies for staff and Contractors.

G. DOMESTIC AND INTERNATIONAL LINKAGE

G-1. Linkage in General

G-1.1. Comment:

Expanding the scope of the Cap-and-Trade program to include additional trading partners provides benefits to compliance entities and more opportunities for cost-effective emissions reductions. Such expansion of the program also provides the longer-term and further-reaching benefit of heightened awareness of climate change impacts and broader recognition of the global nature of the problem. NCPA supports expansion of the State's program subject to the careful and rigorous assessment that ensures the necessary protections for California's compliance entities, the integrity of the program, and the meets the objectives of California's climate policies. (NCPA)

Response: ARB staff appreciates the commenter's support. See also response to 45-day comment I-1.1.

G-2. Linkage with Ontario

G-2.1. Comment:

As noted in our 45 day comments, EDF continues to support the process of linking with the province of Ontario which in January launched a cap-and-trade program that is very similar to California and Quebec's. In a recent Letter to the Editor in the journal Nature we respond to an article entitled "Don't link carbon markets" with some historical clarifications on linked markets and our perspective on when and how to evaluate the

appropriateness of individual linkage relationships. Our submission is included below.⁹⁰⁷

[The commenter attached the following letter to the editor of the journal Nature. Note that the reference in the preceding footnote is not to this letter, although that may have been intended.]

“Carbon markets: extend, don’t limit

“In our view, your headline ‘Don’t link carbon markets’ is poor advice to policymakers (J. Green Nature 543, 484–486; 2017). To cut carbon pollution at the pace and scale that science demands, we must create linkages that can tap into the most cost-effective reductions.

Contrary to Jessica Green’s claim that trading works only as a closed system, the US cap-and-trade programme for sulfur dioxide succeeded alongside an assortment of state and federal standards. The fact that sulfur allowances now trade for a few cents is more vindication than failure, given the deep emissions cuts achieved by the programme and subsequent regulations.

As for existing carbon trading schemes, they are meeting their targets — and can be strengthened over time. California passed an ambitious 2030 target into law last year and the European Union is working to improve its system. The Regional Greenhouse Gas Initiative in the northeastern United States has tightened its carbon cap once and is reassessing it with a view to restricting it further.

However, linking markets is not a panacea and requires care. Emissions-trading systems should stand on their own before linking with other compatible systems, and countries involved in trading should adopt common standards and guidelines to ensure environmental integrity.”

Nathaniel Keohane, Erica Morehouse, Environmental Defense Fund, New York, USA.
nkeohane@edf.org (EDF)

Response: Thank you for the support.

H. SUPPORT FOR THE PROPOSED AMENDMENTS

H-1. General Support

H-1.1. Multiple Comments:

So, again, for Vernon, for Long Beach, and for Palo Alto, we support the resolution; and thank you. (VERNON)

⁹⁰⁷ Available at <http://innovation.luskin.ucla.edu/sites/default/files/FINAL%20CAP%20AND%20TRADE%20REPORT.pdf>

Comment:

TID is very supportive of the Board's adoption of the Cap-and-Trade Program -- the extension of the Cap-and-Trade Program post 2020. We believe that the Cap-and-Trade Program is a key mechanism in ensuring that the utilities of California have the flexibility they need to manage their emissions, and ensures that we are meeting reliability requirements for our customers. This is particularly important for Turlock, because we are our own balancing authority area, and minimizing customer costs is critical because we do serve -- a majority of our customers are in disadvantaged communities. (TURLOCKID2)

Comment:

I wanted to say today that we really appreciate all the time, energy, and collaboration that has gone and involved into Agenda Item 17-8-1, which you know as the amendments for the updates to the Cap-and-Trade Regulation.

This suite of measures complements our collective efforts to meet California's climate change policy goals to maintain both our environmental and our economic goals for the State. (CCPC2)

Comment:

My name is Israel Salas and I'm with the Southern California Gas Company and San Diego Gas & Electric, here to speak in support of the item.

SoCalGas and SDGE participate in the Cap-and-Trade Program on behalf of over 6 and a half [sic-as in transcript] residential and business customers, and we continue to support the program as a well-designed market mechanism to help California achieve its greenhouse gas reduction goals. (SOCALGAS)

Comment:

So now, with our paths firmly established on both air quality and climate, it's nice to turn back to this Board, who has stewarded this program for so long and so effectively, and to continue along with cap-and-trade so we can effectively meet our environmental goals while we maintain a vibrant economy here in California. And with regard to the amendments specifically, they set the stage for an effective post 2020 program.

They maintain critical consumer protections while also setting new steeper annual targets to put us on track to meet our ambitious goals environmentally. And they begin the larger conversation about cost containment and market design that we're going to address here when we start taking on the AB 398, you know, rulemaking.

So with that, PG&E sincerely thanks staff for 4 their months and years of work on this. (PG&E2)

Comment:

LADWP is supportive of the Cap-and-Trade Program. It's an important tool to help the State achieve its long-term greenhouse gas reduction goals. Extension of the program to 2030 is very helpful to help businesses and utilities with their long-term planning.

LADWP has been in the process of transforming our portfolio of generating the resources to lower carbon. We've made a lot of progress over the past couple of decades. As of 2016, we achieved a milestone where our 2016 emissions were 42 percent below our 1990 baseline. So we're very proud of that. And we will continue to make progress in reducing emissions...

So in closing, we're very supportive of this. We appreciate the public process and the dialogue with stakeholders. We look forward to participating in the next round of rulemaking. (LADWP2)

Comment:

And we are supportive of the staff resolution regarding cap-and-trade implementation. Further, we wanted to express our appreciation for the staff's exemplary work on the current regulatory construct. And we look forward to working collaboratively with CARB on the new regulatory development that will be necessary to implement the post 2020 Cap-and-Trade Program. (MINERALSNSTEEL)

Comment:

We do support the Board Resolution 17-8-1 today... (AGCOUNCIL2)

Comment:

We are here in strong support of adoption of today's Cap-and-Trade Program amendments... (SCPPA2)

Comment:

CMUA strongly supports the adoption of these amendments to the Cap-and-Trade Program. These amendments will allow California to achieve its GHG reduction goals in a cost-effective manner that will protect against significant rate increases to customers. (CALMUNIUTILASSOC)

Comment:

Our mission has always been to provide our ratepayers and our local citizens with safe, reliable, and affordable electricity. Well, as I like to call it, moving towards a low CARB diet. We'd like to echo everyone's support for AB 398 and today's scoping plan because they both not only protect but benefit our ratepayers while reducing GHG emissions. And I'd just like to provide some examples of what we do with the proceeds from our directly allocated allowances to benefit our ratepayers and reduce emissions.

We spent about \$10 million. And I'd like to start from the smallest amount to the largest amount. We've allocated about \$150,000 towards rebates to accelerate the adaptation of electric vehicles, which reduces GHG emissions. We've spent nearly \$2 million on energy efficiency retrofits for low-income and multi-family dwellings. So this reaches a segment of the population which normally doesn't benefit from, you know, our discussions and our efforts to reduce GHG emissions.

We've given back our ratepayers nearly 2 and a half million dollars order to, you know, help use a transition towards a cleaner and greener economy. And we've allocated nearly \$6 million towards modernizing our grid, which should enable other technologies such as electric vehicles and time-of-use rates that will help further reduce emissions while benefiting our ratepayers. So again, thank you for your time and thank you for your efforts on fighting climate change. (ROSEVILLE)

Comment:

[O]n behalf of our organization, our members, we'd like to express our appreciation for all of the hard work that you on the Board as well as the staff have put into the development of this. And we'd just like to align ourselves with the comments of our colleagues on the -- from the business community as well. We recognize that the Cap-and-Trade Program is absolutely a fundamental part of California's climate program. And so again, we appreciate all of the hard work that went into this. We support the resolution and we look forward to working with you and staff in its implementation. (WSPA)

Comment:

Cap-and-trade not only establishes a firm GHG emissions target but also due to its flexibility fosters innovative GHG emission reductions that minimize cost to California consumers and businesses...

So to sum up, Southern California Edison thanks CARB Board and staff for all your work on this regulatory update and your efforts to inform the legislative debate. We respectfully request approval of the package before you today. (SOCALEDISON)

Comment:

MSR and NCPA support continuation of the Cap-and-Trade Program and applaud the legislature's recognition of the important role cap-and-trade play in ensuring that the State can meet its ambitious clean energy and climate objectives in the most cost-effective manner. (NCPA-M-S-R)

Comment:

You have done historic work here in the last month. The passage of the two-thirds cap-and-trade bill cements California's leadership on climate in the world. And we think that's very important. We support the adoption of the package in front of you today. It's

the first step in implementing that historic agreement in package. And we believe that you should go through with that.

The Cap-and-Trade Program is key to the overall picture in California. It will result in GHG emission reductions at stationary sources and criteria emission reductions as well. In SMUD's case, our GHG emissions were down 9 percent last year from in-basin facilities, and we expect them to be down another 10 or 11 percent this year, and will continue doing that in the future as we transform our -- the utility industry, in part due to the Cap-and-Trade Program. So we look forward to continued steps in implementation of AB 398 and 617 and a robust open process that we've enjoyed in the past. And I urge you to adopt the package in front of you today. (SMUD2)

Comment:

I want to thank all of the ARB staff for their hard work on the regulatory package that's before you today. EDF has participated in many workshops and provided comments throughout the almost two-year process to develop this regulatory update. We support the Board moving forward with and passing this set of amendments to the Cap-and-Trade Regulation.

This package includes important policy updates that are necessary for the third cap-and-trade compliance period starting in 2018 and made updates necessary to link with Ontario, which EDF also supports.

Passing this package will also preserve the hard work the staff and the Board have done to design a post 2020 program and provide an important regulatory signal to polluters. We look forward to engaging with staff and the Board during the next regulatory phase, which will be needed to implement the direction provided in AB 398 to further strengthen the post 2020 program. (EDF2)

Comment:

And the American Lung Association is here in support of the cap-and-trade proposal here before you today, with the improvements that will be included in compliance with AB 398 and AB 617. (AMLUNGASSOC)

Comment:

We want to thank all of you for your hard work that's gone into these cap-and-trade amendments as well as all of the efforts that you've put forward through the legislature, passing AB 398. We are strong supporters of the Cap-and-Trade Program and we always have been. (CALCHAMBERCOMMERCE2)

Comment:

I would like to acknowledge the tremendous effort of you and your staff, the collaborative effort with the Governor's office, legislative leaders, and key legislative leaders on climate change issues. CCEEB continues to strongly support California's

Cap-and-Trade Program. We're committed to ensuring the success of the program... We look forward to diving into the details of the post 2020 program to implement the negotiated compromise of the authorizing legislation.

It's important that we make this work for all Californians. And there are critical protections for both the environment and the economy in the Cap-and-Trade Program. There are details that must be worked through publicly. And we will be here as a collaborative partner to ensure the successful implementation and continued success of the program. (CCEEB2)

Comment:

Like so many people have said before me, thank you for all the work that you have done and put into this program and that you're going to be putting into the program going forward... And I'm here today in strong support of the proposed amendments especially on behalf of our Sacramento and Oxnard plants, who are both at risk for high leakage. So, again, we are in strong support. (PROCTER&GAMBLE)

Response: Thank you for the support.

H-1.2. Multiple Comments:

CMTA believes that a well-designed cap and trade is the most cost-effective method for achieving GHG emissions reductions while limiting the impact to California's economy. Enabling companies to choose the most economical method for reducing emissions will limit the negative effects of imposing the compliance costs on California manufacturers when no other competitive market also imposes such costs on their manufacturers....

California manufacturers support the development of a well-designed cap and trade program to provide a cost-effective mechanism for reducing GHG emissions. (CMTA)

Comment:

EDF appreciates the careful work that ARB staff is putting in as they make incremental but important technical and clarifying refinements to the cap-and-trade regulation. Many of the changes in the 15 day package are amendments of this nature and while we don't take a specific position on every change we want to recognize the work and attention that went into them. (EDF)

Response: Thank you for the support.

H-2. Post-2020 Continuation of the Cap-and-Trade Program

H-2.1. Multiple Comments:

Support for Continuation of the Cap-and-Trade Program Post-2020

As SCPPA has indicated in past comments, we support implementation of the Cap-and-Trade Program post-2020. The Program, as currently constructed, allows our Members to pass the value of allowance allocations directly to all of their customers, including

those in disadvantaged communities. The continuation of a well-designed Cap-and-Trade Program allows our Member utilities to achieve continued progress in emissions reductions while minimizing ratepayer impacts. SCPPA asserts that extension of such a market-based greenhouse gas (GHG) program is the most cost-effective alternative for achieving our economy-wide GHG reduction goals. (SCPPA)

Comment:

SCE supports a well-designed Cap-and-Trade program to help the state achieve its post-2020 GHG goals. A well-designed Cap-and-Trade Program can help keep total program costs down while achieving our state's environmental targets. The flexibility of a market mechanism will be increasingly important as our state drives towards deeper emission reductions. The regulatory extension of the program post-2020 is critically important and SCE supports ARB efforts to seek extension this year. (SOCALEDISON)

Comment:

The proposed modifications set forth in the Second 15-Day Changes demonstrate Staff's responsiveness and understanding of issues raised by stakeholders in previously filed comments regarding the original Proposed Amendments and First 15-day Changes. The revised proposal for allocation of allowances to electrical distribution utilities (EDUs) for the benefit of California's electricity ratepayers helps to ensure that California's electric utilities' increasing role in effecting greenhouse gas (GHG) emissions reductions can be accomplished while minimizing impacts on electricity rates for the State's residents and businesses. The revised allocation proposal in the Second 15-Day Changes, coupled with the State's commitment to continuation of the Cap-and-Trade program, further facilitates meeting the statewide GHG reduction targets in the most efficient and cost-effective manner possible, while providing a further source of revenues for the State and local communities to invest in programs and measures to further the State's climate objectives. As more fully addressed herein, NCPA encourages the Board to adopt the proposed amendments to the Cap-and-Trade Program with the further revisions set forth in the Second 15-Day Changes...⁹⁰⁸

Since its adoption, the Cap-and-Trade program has played a crucial role in effecting GHG reductions in California. Since that time, the State has continued to expand the scope of its climate policies and reaffirm its commitment to reducing greenhouse gasses and other pollutants. The State's climate objectives are achieved through myriad policies and measures, and no one program can meet all aspects of the State's energy policies and objectives. However, even within that changing landscape, the Cap-and-

⁹⁰⁸ NCPA submitted comments on the August 2, 2016, Proposed Amendments to the Cap-and-Trade Program Regulation on September 19, 2016 (<https://www.arb.ca.gov/lists/com-attach/89-capandtrade16-BWtdOFAhUWMLUgdk.pdf>), as well as comments on the December 21, 2016, First 15-Day Changes (<https://www.arb.ca.gov/lists/com-attach/168-capandtrade16-AmxRNFQIBzVRCAhr.pdf>). NCPA does not reiterate those comments herein, but urges the Board to direct Staff to continue to work with stakeholders on the important issues raised in those comments not addressed in these further proposed modifications, in subsequent rulemakings if necessary.

Trade program continues to play a vital role, providing an opportunity for compliance entities to achieve GHG emissions reductions in a cost-effective and technologically feasible manner, and providing a vehicle that ensures statewide emissions reductions. It meets the objectives of Health & Safety Code section 38562(b) and ensures that direct emissions reductions. It has the added benefit of providing relative cost-certainty to emissions reductions, and a valuable revenue source for a panoply of worthwhile and necessary programs and investments in low-income and disadvantaged communities across the state and within POU service territories. But even so, the program continues to have significant impacts on California's utilities and their ratepayers, making allocation of allowances to EDUs for the benefit of their electricity customers critically important for EDUs.

Adopting the proposed EDU allowance allocation set forth in the Second 15-Day Changes goes far to provide ratepayers with necessary protections. NCPA urges the Board to adopt the revised EDU allowance allocation proposal, and to direct staff to continue to work with the CPUC, CEC, and affected stakeholders to address the outstanding issues and considerations raised in these comments and in comments previously submitted by NCPA. (NCPA)

Comment:

PG&E supports ARB's continued efforts to develop and improve the Cap-and-Trade Regulation in pursuit of the Senate Bill 32 (SB 32) greenhouse gas (GHG) 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 GHG emissions reductions goals beyond 2020 while maintaining a vibrant economy.

Before addressing the April changes, PG&E notes support for ARB's Assembly Bill 197 (AB 197) analysis and agrees with ARB's conclusions. In particular, we agree that ARB has considered the social cost of GHG emissions by estimating the avoided damages from the policy using the U.S. Government's Interagency Working Group of the Social Cost of Greenhouse Gases Social Cost of Carbon. We also agree that the proposed Cap-and-Trade Program design, including gradually declining caps on GHG emissions and a quantitative usage limit on offsets, will result in direct emissions reductions at covered entities including large stationary sources. (PG&E)

Response: Thank you for the support, in particular for the modifications made in the second 15-day language with respect to allocation to electrical distribution utilities. ARB staff also appreciates the comment supporting ARB's social cost of carbon and AB 197 analysis. For more on AB 197, see responses to 45-day comments K-1.9 and L-1.1.

H-2.2. Comment:

Regarding GHG cap and trade market design

We believe that market-based policy incentives should play a prominent role in achieving SB 32's goals, and that adapting the current cap-and-trade scheme is by far the least disruptive policy for achieving this. Cap-and-trade systems give emitters the flexibility to find the most cost-effective strategies for emissions reductions while maintaining strong incentive for innovation, both features that are absent under traditional command and control regulatory measures, as James Bushnell discussed in a blog⁹⁰⁹ on November 21, 2016 and Meredith Fowlie discussed in a blog⁹¹⁰ on June 20, 2016.

Furthermore, dropping cap-and-trade at this point would threaten the regional expansion of market-based GHG policies. The Canadian provinces of Quebec and Ontario are committed to a linked cap-and-trade system, while regional neighbors such as Oregon and Washington state are either considering or have already adopted caps that could be made compatible with California's system. And many countries, including China, look to California's cap-and-trade program as a valuable model. Therefore one of the most important objectives of AB 32 -- for California's example to be emulated by other areas -- is becoming a reality. That progress would be greatly disrupted, if not halted completely, if California were to withdraw from the cap-and-trade system.

Still, we recognize that pure cap-and-trade program would be subject to potentially extreme price volatility (as Borenstein, Bushnell, and their co-authors Frank Wolak and Matthew ZaragozaWatkins showed in an August 2016 working paper⁹¹¹), which is why we strongly advocate firm floor and ceiling prices as part of the extension of California's program to 2030, as Severin Borenstein discussed in a blog⁹¹² on August 15, 2016. (BORENSTEIN)

Response: ARB staff appreciates the commenter's support for continuing the Cap-and-Trade Program. ARB staff did not propose to institute a firm ceiling price as part of this rulemaking, and that portion of the comment is outside the scope of this rulemaking. Rather, ARB has proposed continuing the use of an Allowance Price Containment Reserve, with a single tier price. See response to 45-day comment H-4.5. For more on the alternatives assessed as part of this rulemaking, see response to 45-day comment L-1.1.

⁹⁰⁹ James Bushnell, "Looking for Environmental Certainty in All the Wrong Places," Energy Institute at Haas blog, November 21, 2016. <https://energyathaas.wordpress.com/2016/11/21/looking-for-environmental-certainty-in-all-thewrong-places/>. ³ Meredith Fowlie, "Time to Unleash the Carbon Market," Energy Institute at Haas blog, June 20, 2016.

<https://energyathaas.wordpress.com/2016/06/20/time-to-unleash-the-carbon-market/>

⁹¹⁰ Meredith Fowlie, "Time to Unleash the Carbon Market," Energy Institute at Haas blog, June 20, 2016.

<https://energyathaas.wordpress.com/2016/06/20/time-to-unleash-the-carbon-market/>

⁹¹¹ Severin Borenstein, James Bushnell, Frank Wolak and Matthew Zaragoza-Watkins, "Expecting the Unexpected: Emissions Uncertainty and Environmental Market Design," Energy Institute at Haas Working Paper #274, August 2016, <http://ei.haas.berkeley.edu/research/papers/WP274.pdf>

⁹¹² Severin Borenstein, "Fixing a Major Flaw in Cap and Trade," Energy Institute at Haas blog, August 15, 2016. <https://energyathaas.wordpress.com/2016/08/15/fixing-a-major-flaw-in-cap-and-trade/>

H-2.3. Multiple Comments:

CIOMA believes the best path to achieve the state's long-range environmental goals is through an integrated and flexible policy framework that optimizes technologically feasible, cost-effective, and sustainable greenhouse gas (GHG) emissions reductions. We continue to believe that the most comprehensive and effective scenario alternative ARB Staff has developed for recommendation to the Air Resources Board for adoption in June is Alternative 3- All Cap-and-Trade: 2030 GHG and Air Quality Reductions. (CIOMA)

Comment:

CCPC continues to believe that the most comprehensive and effective scenario alternative ARB Staff has developed for recommendation to the Air Resources Board for adoption in June is Alternative 3 – All Cap-and-Trade: 2030 GHG and Air Quality Reductions.

The options offered in the Scenario 3 design include existing statutory mandates and capturing the balance of emissions through the cap-and-trade program will meet the objective for the Scoping Plan Update. (CCPC)

Response: This comment appears to be related to the proposed 2017 Scoping Plan Update, and is therefore outside the scope of this rulemaking.

H-2.4. Multiple Comments:

Five years ago, the California Air Resources Board (ARB) launched the world's most complex cap-and-trade program. Although the program is working well in some areas, a number of challenges remain and a key test will come in the post-2020 period as the program cap continues to decline. As ARB looks to move beyond the initial iteration of cap-and-trade, it is vital for the program to carefully examine any policies that would drive away potential partners or sacrifice opportunities to decrease costs. The state's post-2020 policies should support the opportunity for new, emerging technologies and emissions control strategies that allow us to innovate. In light of Senate Bill 32's (Chapter 249, 2016) even more ambitious carbon reduction target, it is imperative that the regulation meet our environmental goals, while maintaining a strong economy and reducing leakage. (AGCOUNCIL)

Comment:

However, the food processors are also very much aware that this is not the end of the fight. This is the battle to make sure that we meet our compliance obligations and meet our environmental goals as they're going to continue. And in that essence you've heard us talk before about the idea of new technology investments, as well as incentive reforms. Food processors are going to be facing a very difficult task in being able to meet these compliance obligations as we move forward. And we would like the Board

to lend its strength and its ability to push through these types of things to see that there's more investment in new technologies.

We are not just depending on you. The League itself is engaged in a new technology study itself to determine exactly where the status is for the types of technologies that we employ in our processing.

Also incentive program reform. You heard me talk about this before. We really need to bring this together so it serves one purpose. And the incentive reforms in both the PUC as well as the Energy Commission, and maybe even having some types of incentives be able to come out of the ARB would be wonderful in terms of our ability to be able to employ these new technologies and to move forward as we attempt to reach these goals. (FOODPROD)

Comment:

The area that I wanted to emphasize is one that John Larrea touched on, which is the incentive funding and the need for advanced technology. In our case in the food processing industry, there are no new black boxes that we can look to to increase our efficiency much more than where we're at now.

We respect the role of the Air Resources Board as being a leader in technology-forcing regulations, and now we're here to ask to have a greater role in the partnership for developing new and innovative technologies for use by our industry, where we can be a leader within the State, within the nation, and within the world. (BOSWELL)

Response: The comment requests an examination of emerging technologies as the State's overall climate policies advance. The comment does not recommend or oppose any specific 15-day amendment proposed in this rulemaking, so no further response is needed.

H-2.5. Comment:

TID remains committed to working towards the State's climate and clean energy goals, and supports the extension of Cap & Trade, notwithstanding numerous implementation concerns outlined below, and offers the following comments on the recently released Draft Cap & Trade Regulations. TID also supports the comments from other utility organizations, namely the Joint Utility Group. (TURLOCKID)

Response: Thank you for the support. The commenters additional comments are included and responded to elsewhere in this FSOR.

I. OPPOSITION TO THE PROPOSED AMENDMENTS

I-1.1. Comment:

CalChamber strives to remain a productive stakeholder throughout the AB 32 implementation process as well as in the future with post-2020 climate policies, in order to advance the greenhouse gas (GHG) emission reduction goals in the most cost-

effective manner while protecting California businesses and allowing for economic growth across all sectors of the economy. We have long maintained that if designed properly, a market-based mechanism has the ability to garner significant GHG reductions in a cost-effective manner.

A cap-and-trade program will be a more cost-effective approach than command and control and less likely to discriminate unfairly against particular industrial sectors. California's greenhouse gas reduction laws post 2020 will be unworkable without a well-designed market mechanism. The command and control measures that would be used to achieve a 2030 GHG emission reduction target of 40% below 1990 levels will be harsh and severely impact the quality of life of Californians. This will require cutting per capita GHG emissions nearly in half over ten years, after already achieving the easiest and most cost-effective reductions.

Governor Brown has noted that an extension of cap-and-trade post 2020 is unfinished business. In order for there to be an extension, there needs to be legislative authority. A market mechanism can be adopted with a simple majority vote of the California Legislature, however, if the CARB is looking for a revenue stream beyond the cost of administering the program, this will require a supermajority in order to approve the tax. (CALCHAMBER)

Response: ARB staff appreciates the commenter's general support for cap-and-trade. With respect to the portion of the comment expressing concerns over legislative authority, see response to 45-day comment K-1.8. This comment also references more specific concerns by the same commenter; those specific comments, and staff responses, are included elsewhere in this FSOR.

J. ALTERNATIVES TO THE CAP-AND-TRADE PROGRAM

J-1. GHG Emissions Pricing Alternatives

J-1.1. Comment:

A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. (EJAC)

Response: See responses to 45-day comments L-2.2 and L-3.2.

J-1.2. Comment:

~~Develop a unified policy similar to (but better constructed than) CAPCOA's for trading GHG credits among districts.~~ Delete the following sentence: "Where further project design or regional investments are infeasible or not proven to be effective, it may be appropriate and feasible to mitigate project emissions through purchasing and retiring carbon credits issued by a recognized and reputable accredited carbon registry." CAPCOA is creating a new carbon market that EJAC has raised concerns about, and it should not be authorized by being in the Scoping Plan. (EJAC)

Response: This portion of the comment appears to have been submitted in reference to the ongoing 2017 Scoping Plan Update process, and therefore is outside the scope of this rulemaking.

J-2. Multiple, Mixed or Additional Strategies

J-2.1. Multiple Comments:

With respect to implementation of AB 398 and AB 617, we were supportive of both of those bills, and believe that those bills provide an important degree of consistency for the program and legal certainty for the program, and we're very much looking forward to working with staff in an open and transparent process for the implementation of those bills. (TURLOCKID2)

Comment:

We were supportive of the AB 398 and 617 to move California forward and provide the certainty necessary for that. (CMTA2)

Comment:

And I respect the staid comments of all of my colleagues, but, y'all, this is a moment for celebration. This is an historic moment, and we need to recognize that.

PG&E here -- is obviously here to support the historic compromise that was made last week. I can't believe it was just last week. It feels like a lifetime ago. But this is an historic moment. And it was a good compromise; and I know that because we're all a little unhappy.

But's it still an important moment. You know, this bill came together and it was rightfully called a unicorn. It's a remarkable and hard-fought compromise, and it reaffirms the unique and beneficial role that cap-and-trade has and plays alongside our other many direct measures.

You know, we've heard many times it's a portfolio approach. Cap-and-trade has a special place among those programs, but it's not the only one. Additionally, the legislature showed that they clearly heard the voices of those who are not just concerned with climate but also with the air in their backyard and their neighborhood, and they passed AB 617. And we came together and we made a deal on both of these important policy issues. That's special. (PG&E2)

Comment:

We are here in strong support of adoption of today's Cap-and-Trade Program amendments and we're also in strong support of passage of Assembly Bill 398 as well last week. (SCPPA2)

Comment:

Shell appreciates the tremendous efforts by ARB Board and staff in the development of the program. We appreciate the clarity and certainty of the path forward for California's continued global leadership, for reducing greenhouse gas emissions that is provided by AB 398. It's consistent with Shell's support of the Paris Accord and the Under 2 MOU and the support of market-based mechanisms to minimize the impacts to the economy and costs to the consumer.

We, as most stakeholders, would say it's not perfect. Echoing Mary's opening remarks, any outcome that garners such broad support - industry, environment, labor, business, Democrat, Republicans - is truly notable indeed and almost always requires some give and take. So I think that echoes Mr. Bergmann [sic] from PG&E as well.

Bottom line, we look forward to the development of the upcoming cap-and-trade package consistent with the legislative direction and supporting staff as helpful towards this aim. (SHELL)

Comment:

CMUA also supported AB 398, and we look forward to working with ARB staff to implement that bill in an open and public process. (CALMUNIUTILASSOC)

Comment:

SCE applauds the passage of AB 398 and 617 and continues our strong support for California's climate goals and, specifically, the Cap-and-Trade Program, which we view as an essential part of the State's greenhouse gas reduction efforts. SCE has proudly supported CARB's program in the legislature and we're here in support of extending the Cap-and-Trade Program today. (SOCALEDISON)

Comment:

The agricultural industry was very engaged on the cap-and-trade discussion that just happened in the legislature because of our unique nature of being highly trade exposed and in not being able to pass our costs on to consumers. Many in the agricultural industry including the three organizations that I'm representing today ultimately supported AB 398. We see that AB 32 and SB 32 set very high goals for the State of California, and we believe that AB 398 is the best way in achieving those goals while also making sure that the agricultural industry can survive in California. (AGPROCESS)

Comment:

First of all, I'd like to offer thanks to both the Board and the staff and the stakeholders that worked so hard to make sure that we got these types of amendments moving forward. But we also owe a debt of gratitude to a lot of the members over there at the legislature, not only Assemblyman Garcia for carrying the bill, but also those legislators who stood up and actually supplied those necessary votes in the face of a lot of

opposition in order to be able to protect those companies that are most vulnerable down in our areas. (FOODPROD)

Comment:

And we were strong supporters of that legislative package [AB 398 and AB 617] and wanted to express our appreciation to Assemblyman Garcia and to Assembly Member Cristina Garcia for their leadership in developing this package that both extends the program and adds new requirements for local air pollution monitoring, community action plans, enhanced enforcement, and facility upgrades, as we believe these are meaningful and important improvements, and we look forward to the implementation plan that's going to be developed soon.

Clearly, local air pollution and climate action must be tackled together, and we believe this package will bring the tools that we need to ensure this happens.

Climate change of course is one of the most important health issues. That's why the Lung Association is so engaged in this overall effort. We view the Cap-and-Trade Program as a key component of our overall strategy. We continue to want to remind everybody of our strong support for the overall package; that includes a strong regulatory component of course in addition to the market component. This program continues our national and global leadership. We appreciate the hard work, and we look forward to working together with you on the next steps. (AMLUNGASSOC)

Comment:

Earlier this week, the Governor signed AB 398 into law. That was supported by our membership. (CCEEB2)

Comment:

I'm here today to let you know that we did support AB 398. (PROCTER&GAMBLE)

Comment:

As we move forward, we are in support of AB 398. (BOSWELL)

Response: Since the commenters did not make a specific request regarding the proposed regulatory amendments in this rulemaking, no response is needed.

J-2.2. Comment:

The Scoping Plan Economic Analysis must consider carbon tax, command and control regulation, and Cap-and-Dividend or Fee-and-Dividend. Cap-and-Trade must be eliminated. (EJAC)

Response: See response to 45-day comment L-3.1.

J-2.3. Comment:

Tier pricing for allowances for facilities in EJ communities, making it more expensive to pollute in those communities. (EJAC)

Response: See response to 45-day comment L-3.3.

J-2.4. Comment:

A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program.

- a. Increase enforcement of existing environmental and climate laws, increasing penalties for violations in DACs.
- b. Establish a state run “Carbon Investment Fund” allowing the private financial sector to invest in Carbon Futures. Pay dividends through enforcement fines, permit fees and carbon tax receipts.
- c. Better coordinate climate pollution and local criteria pollutants programs.
- d. Place individual caps on emission sources, rather than using a market-wide cap. Set up a per-facility emissions trigger that will tighten controls when a certain level is reached. Include language in Scoping Plan on facility caps.
- e. Establish a moratorium on refinery permits.
- f. Set goal of 50% emissions reduction in Oil and Gas sectors by 2030. Aggressively reduce emissions from these sectors, including fugitive and methane emissions from extraction and production.
- g. Put emissions caps on the largest polluters.
- h. If Cap-and-Trade continues, do not give out more free allowances.
- i. Do not exempt biomass burning activities.
- j. Do not allow regulated entities to apply for California Climate Investments funding.
- k. Increase the floor price to the real price of carbon; use the highest price offered, not the lowest. Incorporate industry’s externalized costs into the cost of carbon (as is done with the mitigation grant program at Port of Long Beach). Calculate the cumulative impacts so they can be mitigated. Ensure that polluting facilities are paying the societal costs of their emissions, rather than externalizing them. (EJAC)

Response: See responses to 45-day comments L-3.2 and N-1.4. A difference between the earlier draft of this comment submitted during the 45-day and first 15-day comment periods, and this comment is a request to include language

about facility caps in the Scoping Plan. This portion of the comment is outside the scope of this rulemaking, since it is recommendation for the ongoing 2017 Scoping Plan Update process, and staff has not proposed such language as part of this rulemaking.

J-2.5. Comment:

Regarding cap and trade alternatives

Capping greenhouse gas emissions from individual facilities, or even a small set of facilities, could greatly increase the cost of meeting state-wide GHG emissions reduction targets. In its recent update to the economic analysis of its scoping plan, the ARB estimated that the “cap-and-tax” scenario would more than double direct compliance costs and, more significantly, lead to lost California production on the order of tens of Billions of dollars.⁹¹³

Individual facility caps also increase the risks of emissions leakage. The higher the costs incurred by a firm to comply with the regulation, the more likely it becomes that production (and associated emissions) are induced to move outside the state. One obvious option for complying with a facility specific cap is to shut the facility down more frequently or for extended periods of time. In the case of refineries, this would almost certainly increase the import of refined product into California and sharply increase fuel prices. Evidence supporting this outcome can be found in the California gasoline markets response to the outage of the Exxon-Mobil Torrance refinery that began in February 2015. California ARB emissions data show that direct emissions from this refinery fell by 15 million metric tons in 2015 as a result of the outage. However, California gasoline consumption did not decline in 2015, despite significant increases in refinery margins.⁹¹⁴ The lost supply was made up through increased output from the remaining operable California refineries and from increased imports. If binding emissions limits on the remaining refineries had been in place during 2015, further pressure would have been placed on both imports and on price increases to balance the gasoline market.

Facility level caps have been proposed in large part under the belief that such policies would best address concerns over local pollutants. However, as Severin Borenstein discussed in a January 17, 2017 blog⁹¹⁵, regulating GHG at specific facilities is not the same as capping or directly regulating local pollutants at those same facilities. Discussions regarding the cap and tax proposal seem to assume that a reduction in GHG from a facility will produce a proportional reduction in local pollutants. It is

⁹¹³ California Air Resources Board, proposed “2017 Scoping Plan Update,” March 28, 2017. <https://www.arb.ca.gov/cc/scopingplan/meetings/032817/sp-march-workshop-slides.pdf>

⁹¹⁴ California Board of Equalization. Net Taxable Gasoline Gallons. http://www.boe.ca.gov/sptaxprog/reports/MVF_10_Year_Report.pdf

⁹¹⁵ Severin Borenstein, “Fight Both Local and Global Pollution, But Separately,” Energy Institute at Haas Blog, January 17, 2017. <https://energyathaas.wordpress.com/2017/01/17/fight-local-and-global-pollution-but-separately/>

possible that this will not be true. In fact, there are scenarios in which capping GHG at a facility could have no effect on local pollutants from that facility or even lead to an increase. (BORENSTEIN)

Response: The comment raises concerns related to certain commenters' request to place facility level caps on individual facilities. ARB staff appreciates the comment, and notes that such a change was not proposed as part of this rulemaking and is therefore outside the scope of the rulemaking.

J-2.6. Comment:

Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities. Include an analysis on where/how GHGs are increasing and specify strategies to prevent and reduce those emissions, especially in EJ communities; these strategies include no trading, no offsets, and no free allowances in those communities. Continue OEHHA emissions study on EJ communities, including facilities with emissions increases that used offsets and received free allowances. (EJAC)

Response: This comment is broader than the current rulemaking, and appears to have been submitted as a comment on the ongoing 2017 Scoping Plan Update process. As such, no further response is required. Nonetheless, see also response to 45-day comment K-1.3.

K. PUBLIC PROCESS

K-1.1. Comment:

Ensure that the Adaptive Management tool is adequate for real-time monitoring and intervention. Provide real-time air data to communities from local emitters. There must be at least two EJAC members on the Adaptive Management work group. To demonstrate how the tool can help communities, complete an Adaptive Management analysis for Kern County. (EJAC)

Response: The comment appears to refer to a process and a tool that are outside the scope of this rulemaking. As such, no further response is required.

K-1.2. Comment:

Provide a full analysis of carbon tax and cap-and-tax. (EJAC)

Response: This comment appears to refer to the ongoing 2017 Scoping Plan Update process. Notwithstanding this, please see response to 45-day comments L-3.1 and N-1.1.

K-1.3. Multiple Comments:

PGE requests that CARB work closely and transparently with CAISO to facilitate CAISO's timely implementation of the long-term EIM GHG accounting solution ("2-pass

model”). Additionally, PGE requests that CARB provide comments and feedback during CAISO’s development process to help ensure CARB’s adoption of this model and adjust its regulatory program to fit with the technical capabilities of the modified optimization. (PORTLANDGENELEC)

Comment:

Powerex is strongly supportive of the efforts made by CARB staff to date and, should it become necessary, supports CARB staff developing further interim measures should the two-pass solution be unable to be implemented in a reasonable timeframe. (POWEREX)

Response: See response to 45-day comment M-1.6.

L. CLIMATE PROGRAMS AND SCOPING PLAN

L-1.1. Comment:

Initial Recommendations prepared Aug. 26, 2016; revisions made Dec. 22, 2016 and March 30, 2017.

March 30, 2017 new text underlined, deleted text in ~~strikeout~~.

Industry	
Equity	
1	State in the Scoping Plan that it is a priority to reduce emissions in EJ communities, and to ensure no emissions increases happen there, <u>and specify the strategies that are achieving this</u> . Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities. <u>Include an analysis on where/how GHGs are increasing and specify strategies to prevent and reduce those emissions, especially in EJ communities; these strategies include no trading, no offsets, and no free allowances in those communities. Continue OEHHA emissions study on EJ communities, including facilities with emissions increases that used offsets and received free allowances.</u>
2	Use a "loading order" for Industry similar to the one that is used by the California Energy Commission for supplying demand, <u>such as: (1) reduce fossil fuel use (extraction, operations, supply, feedstock source), (2) reduce emissions through efficiency (technology, innovations), (3) controls to prevent emissions increase</u> . Always prioritize the approval and use of the most efficient and low-carbon technologies, facilities, and projects over high-polluting ones. <u>This could be implemented for the LCFS.</u>
3	Address localized impacts of short-lived climate pollutant emissions, such as black carbon from all sources.

4	<p>A big design flaw of Cap-and-Trade is having an ambiguous economy-wide cap. Eliminate Cap-and-Trade, replace it with a non-trading option system like a carbon tax or fee and dividend program. In addition:</p> <ol style="list-style-type: none"> Increase enforcement of existing environmental and climate laws, increasing penalties for violations in DACs. Establish a state run “Carbon Investment Fund” allowing the private financial sector to invest in Carbon Futures. Pay dividends through enforcement fines, permit fees and carbon tax receipts. Better coordinate climate pollution and local criteria pollutants programs. Place individual caps on emission sources, rather than using a market-wide cap. Set up a per-facility emissions trigger that will tighten controls when a certain level is reached. <u>Include language in Scoping Plan on facility caps.</u> Establish a moratorium on refinery permits. Set goal of 50% emissions reduction in Oil and Gas sectors by 2030. Aggressively reduce emissions from these sectors, including fugitive and methane emissions from extraction and production. Put emissions caps on the largest polluters. If Cap-and-Trade continues, do not give out more free allowances. Do not exempt biomass burning activities. Do not allow regulated entities to apply for California Climate Investments funding. Increase the floor price to the real price of carbon; use the highest price offered, not the lowest. Incorporate industry’s externalized costs into the cost of carbon (as is done with the mitigation grant program at Port of Long Beach). Calculate the cumulative impacts so they can be mitigated. Ensure that polluting facilities are paying the societal costs of their emissions, rather than externalizing them.
5	<p>The Scoping Plan Economic Analysis must consider carbon tax, command and control regulation, and Cap-and-Dividend or Fee-and-Dividend. Cap-and-Trade must be eliminated.</p>

<u>Industry</u>	
	<p>The price of carbon must be increased, with the resulting funds invested in local communities to ensure all benefits from a greenhouse gas free future. <u>Provide a full analysis of carbon tax and cap-and-tax.</u></p>
6	<p>Expand the definition of <i>economy</i> to include costs to the public (e.g., U.S. EPA social cost calculator). <u>Include health care costs in social cost of carbon.</u> Conduct an economic analysis that would account for the cost to public health (beyond cancer, respiratory and cardiovascular diseases) and environmental burdens from greenhouse gases. Include the Integrated Transport and Health Impacts Model (ITHIM) in the analysis. Ensure that ARB coordinates with other state agencies in this effort.</p>

7	Ensure that the Adaptive Management tool is adequate for real-time monitoring and intervention. <u>Provide real-time air data to communities from local emitters.</u> There must be at least two EJAC members on the Adaptive Management work group. To demonstrate how the tool can help communities, complete an Adaptive Management analysis for Kern County.
8	To address tension between workers and community members who live in polluted areas, there needs to be access to economic stability and a just transition to the new clean economy. Ensure that workers in Environmental Justice communities whose livelihood is affected from a move to cleaner technologies have access to economic opportunities in that new clean economy and that local businesses continue to employ workers from that community. <u>Include a just transition fund in the use of any climate funds.</u>
9	Do not commit California to continuing Cap-and-Trade through the Clean Power Plan. Since carbon trading cannot be verified, ensure that the Clean Power Plan power purchases are from sustainable, renewable power plants.
10	Eliminate offsets. <u>However, if this recommendation is not accepted and offsets are used, they must offset the emissions in the area where the emissions occur. Offsets must be in the state; do not allow out-of-state offsets.</u> Actions and investments taken by industry to reduce emissions need to be reinvested in the communities where the emissions have occurred. Any benefits from greenhouse gas reduction measures must affect California first. In addition to California emissions, also consider activities that can reduce pollution coming from across the Mexican border, to reduce emissions in the border region. Do not pursue or include reducing emissions from deforestation and forest degradation (REDD) international offsets in the Scoping Plan. <u>ARB should commit to evaluate the emissions impacts of offsets and free allowances in EJ communities, including if Cap-and-Trade is extended/chosen, and then publish this study and consult with the EJAC.</u>
11	<u>Do not allow out-of-state forest offsets—offsets should apply to in-state urban forests.</u>
44 12	Add AB 197 and SB 350 as a Known Commitments for this sector and remove “Develop a regulatory accounting and implementation methodology for the implementation of carbon capture, and sequestration projects” as a potential new measure. <u>Include detail in Scoping Plan of how AB 197 implementation will work to reduce emissions, especially for EJ communities.</u>
13	<u>Delete the word “unlikely” from the following sentence on page 55 of the Scoping Plan: Implement Adaptive Management to monitor for and address any unlikely increases in toxic or criteria pollutant emissions due to implementation of the Cap-and-Trade Program. Include ARB’s response to the CEJA and OEHHA reports in the Scoping Plan and a commitment to prevent emissions increases, especially in EJ communities.</u>
14	<u>Commit to reducing oil. This includes a moratorium on new or expanded fossil fuel infrastructure, limiting oil and gas exports now to close that loophole, and placing quality</u>

<u>Industry</u>	
	<u>controls on feedstocks so as to not import extreme oil (tar sands, Bakken crude).</u>
<u>Coordination</u>	
<u>42 15</u>	ARB needs to examine ways to increase its partnerships with and oversight over air districts using its existing authority. Local air districts need to be held accountable to the same standards as ARB. Promises need to be documented and strictly enforceable. If an air district chooses to have stronger standards than ARB, that air district must have the power to enforce those stronger standards without interference from ARB.
<u>43 16</u>	<p>Stop “passing the buck” from agency to agency and fix the problems. All agencies need to take responsibility for all pollutants. Coordinate efforts among agencies when necessary, and among local governments and communities. Implement the following measures:</p> <ul style="list-style-type: none"> a. Improve community and neighborhood level air pollution monitoring. b. Add EJ members to all agency boards and committees. c. Tier pricing for allowances for facilities in EJ communities, making it more expensive to pollute in those communities. d. Improve communications about air quality between polluters and schools and nearby residents, both for individual accidents and in terms of overall facility emissions. Develop a cooperative, productive discourse. e. Provide easily accessible and immediate notification to schools and nearby residents in the event of a facility accident; current notification is much too slow. Develop and make accessible tools like the real-time air quality advisory network (RAAN) phone application, so residents can access real-time air quality information at the neighborhood level. f. Establish better coordination between enforcement agencies. Expand air quality night enforcement so that all communities have around-the-clock enforcement to address off-hours violations.
<u>14 17</u>	Develop a unified policy similar to (but better constructed than) CAPCOA's for trading GHG credits among districts. Delete the following sentence: “Where further project design or regional investments are infeasible or not proven to be effective, it may be appropriate and feasible to mitigate project emissions through purchasing and retiring carbon credits issued by a recognized and reputable accredited carbon registry.” CAPCOA is creating a new carbon market that EJAC has raised concerns about, and it should not be authorized by being in the Scoping Plan.
<u>Partnership with Environmental Justice Communities</u>	

45 18	Create a thorough air quality monitoring system and deputize the community to participate in that network through databases, apps, and community science. Fund a program to provide communities with the tools and training they need to participate. Identify the pockets not being monitored and also the hot spots. ARB must take a greater responsibility for monitoring. Ensure that all monitoring covers both greenhouse gas pollutants and criteria pollutants, to expand the state's databases and accurately characterize all communities, so that CalEnviroScreen can more reliably identify areas that qualify for funding. Make monitoring transparent and accessible. <u>Include language in Scoping Plan committing to improved air monitoring.</u>
<u>Long-Term Vision</u>	
46 19	The Industry sector must present a vision of how California is transitioning to a clean energy economy, with clean businesses that will not harm disadvantaged communities. This vision
<u>Industry</u>	
	must focus both on the environment and the economy, including the jobs and taxes that will come from a transition to a clean energy economy. For example, analyze the gaps between jobs lost in fossil fuel industry and jobs gained in cleaner industries.
17 20	Explore scenarios for maintaining local jobs when refineries shut down. <u>Include a just transition fund for workers.</u>

(EJAC)

Response: This comment was originally submitted as part of the 45-day comment period. See responses to 45-day comment N-1.4. The comment includes several new elements (shown as underlined text) that also seeks to limit offsets completely, or at least to only those that occur in California. ARB staff has not proposed restricting offsets to only California as part of this rulemaking, and the comment is therefore outside the scope of this rulemaking. Nonetheless, ARB staff notes that restricting offsets to California could face legal challenges, as well as not optimally incentivize real emission reductions in sectors outside the scope of the Cap-and-Trade Program.

M. MRR

M-1.1. Comment:

Through standardized metrics, ensure that emission reductions from AB 32 activities are being achieved, especially in EJ communities. (EJAC)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

M-1.2. Comment:

The ARB has proposed changing the deadlines for verification of product data for facilities subject to the product-based benchmark from September 1 to August 10. While CLFP appreciates the compromise in setting the proposed date to August 10 from the previously proposed date of August 1, we still believe that such a move will do little to mitigate the additional difficulties associated with the verification deadline for that portion of the food processing industry that is subject to seasonality.

Seasonal California processors are subject to summer harvest cycles which can run from late-June through mid-October. The average season for food processing runs between 70 to 90 days. Once the harvest commences, facilities will operate non-stop, 24-hours a day, processing fruits and vegetables as they are harvested.

Under the current regulation, food processors are required to report product-based data in April. The verification of the reported data then commences. As a result, verification of a seasonal facility's reported data occurs during the height of the processing season.

Even with the current September 1 deadline, many food processors are burdened with a time consuming verification process, hosting verifiers and onsite facility verifications, during the most intensive period for food processing facilities. Many of these facilities struggle to meet the current deadlines due to the inability to assign vital staff or resources at the height of the processing season. Moving the deadline for verification up by three weeks will only further increase the difficulties for food processors.

An unintentional consequence of moving the deadlines may result in increased costs for facilities subject to the MRR. Verifiers will have less time in which to verify the facility data. Additionally, the new deadlines may limit the number of clients a verifier can accommodate under the new deadline. This is likely increase the costs of verification as verifiers attempt to make up for the loss in clientele.

ARB staff central issue is that the vast majority of verifications were being filed at or on the September 1 deadline. However, moving the deadline, giving staff more time, does nothing to alleviate the pressure on seasonal facilities subject to such a deadline and, in fact, may make meeting the deadline even more difficult.

RECOMMENDATION

Given the size and unique aspects of the sector represented by seasonal food processors, it remains unclear why ARB cannot try to accommodate these few facilities? CLFP recommends keeping the current deadline for seasonal facilities that meet these specified criteria.

That said, CLFP still believes that incentivizing facilities to meet or beat the verification deadline constitutes a better answer. Incentives could take the form of early deposits of allowances into those facilities' CITSS accounts or options designed to provide compliance leeway specific to the facility or sector.

Impact on section 95133 (Conflict of Interest) of Proposed Verification Date Change

Conflict of Interest Approvals

Given the proposed shortening of the verification deadline, CLFP urges ARB to find a way to streamline the process for Conflict of Interests reviews for verifiers. Some food processors have experienced a delay in the start of verification process do to the verifier not receiving a Conflict of Interest clearance from the ARB in a timely manner. For facilities using the same verifiers, not new ones, it seems reasonable that such reviews and approval should only take a day - not two weeks as one food processor reported the CLFP. Since the ARB is proposing to move back the deadline three weeks CLFP recommends that steps be taken to guarantee the timely approval of verifiers. (FOODPROCESSORS)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

M-1.3. Comment:

CIOMA is opposed to changing the Mandatory Reporting Regulation amendments (MRR) report verification deadline to August 1st. We believe that moving the verification deadline from September 1st to August 1st will create a significant burden for both reporting entities and verification bodies. Unfortunately, the staff MRR report states:

“At this time staff is not make [sic] changes to the originally proposed verification deadline of August 1. Staff plans to hold a workshop in early 2017 to further discuss the verification deadline. As such, staff is retaining the amended language, but additional proposed amendments may be issued in a second package of proposed modified amendments, with an additional comment period based on further dialogue with stakeholders.”

We continue to advocate for maintaining the September 1st MRR verification deadline and, if necessary, consider pushing back cap-and-trade deadlines that appear to have flexibility.

However, if ARB feels strongly about moving forward with the August 1st deadline, we would continue to request:

- ARB develops a process to streamline the process for Conflict of Interests reviews for verifiers. For facilities using the same verifiers, not new ones, it seems reasonable that such reviews and approval should only take a day - not two weeks;
- ARB considers efficiencies within ARB staff and verifier activities allowing a compromise verification completion date in recognition of the added scheduling burden to reporting entities;

- That flexibility be provided to obligated parties if reporting dates create problems arising from industry-specific sector needs (such as crop processing or high demand conditions);
- Provide incentives for advanced reporting and verification;
- Alignment of penalties, allowing for verification compliance problems beyond the control of the obligated party; and,
- Recognition of good-faith efforts by obligated parties to provide timely compliance that is otherwise compromised.

(CIOMA)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

M-1.4. Comment:

CCPC continues to be opposed to changing the Mandatory Reporting Regulation amendments (MRR) report verification deadline to August. We believe that moving the verification deadline from September to August will create a significant burden for both reporting entities and verification bodies. We continue to advocate for maintaining the September 1st MRR verification deadline and, if necessary, consider pushing back cap-and-trade deadlines that appear to have flexibility.

However if ARB feels strongly about moving forward with the August deadline, we would continue to request:

ARB develops a process to streamline the process for Conflict of Interests reviews for verifiers. For facilities using the same verifiers, not new ones, it seems reasonable that such reviews and approval should only take a day - not two weeks;

ARB considers efficiencies within ARB staff and verifier activities allowing a compromise verification completion date in recognition of the added scheduling burden to reporting entities;

That flexibility be provided to obligated parties if reporting dates create problems arising from industry-specific sector needs (such as crop processing or high demand conditions);

Provide incentives for advanced reporting and verification;

Alignment of penalties, allowing for verification compliance problems beyond the control of the obligated party; and,

Recognition of good-faith efforts by obligated parties to provide timely compliance that is otherwise compromised. (CCPC)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

M-1.5. Comment:

In Section 95103 Greenhouse Gas Reporting Requirements, ARB is proposing to move up the deadline from September 1 to August 10 for when a reporting entity must complete and submit their third-party verification. Ag Council is concerned that shortening the timeframe for the assessments would impact our member's ability to work with the verifier to adequately address any questions and concerns. The reduced time period would also mean a rushed verification process, which could possibly lead to more errors. Our recommendation is to maintain the September 1 deadline. (AGCOUNCIL)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

M-1.6. Comment:

Finally, the ISO supports ARB's proposal to remove the ISO as a reporting entity under the mandatory reporting regulation. (CAISO)

Response: These comments address the Mandatory Reporting Regulation and are addressed in the 2017 Mandatory Reporting Regulation Final Statement of Reasons.

VII. PEER REVIEW

Health and Safety Code section 57004 sets forth the requirements of peer review of identified portions of rulemakings proposed by entities within the California Environmental Protection Agency, including ARB. Specifically, the scientific basis or scientific portion of a proposed rule may be subject to this peer review process. Here, ARB determined that the rulemaking at issue does not contain scientific basis or a scientific portion subject to peer review, and thus no peer review as set forth in section 57004 was or needed to be performed.

ATTACHMENT B: ACRONYMS

AAR	Alternative account representative
AB 32	Assembly Bill 32 -- California Global Warming Solutions Act of 2006
AF	assistance factor
AHA	Allowance Holding Account
APA	Administrative Procedures Act
APCR	Allowance Price Containment Reserve
APD	Authorized Project Designee
ARB	California Air Resources Board
BAA	Balancing Authority Area
BP	British Petroleum
BPA	Bonneville Power Administration
CAA	Clean Air Act
CAISO	California Independent System Operator
CAR	Climate Action Reserve
CARB	California Air Resources Board
CCA	community choice aggregator
CCEEB	California Council on Environmental and Economic Balance
CCR	California Code of Regulations
CEA	Commodities Exchange Act
CEC	California Energy Commission
CEJA	California Environmental Justice Alliance
CEQA	California Environmental Quality Act
CFTC	Commodity Futures Trading Commission
CHP	combined heat and power
CITSS	Compliance Instrument Tracking System Service
CMCA	Carbon Market Compliance Association
CMTA	California Manufacturers & Technology Association
CMUA	California Municipal Utilities Association
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
COI	Cost of Implementation (Regulation)
CHP	combined heat and power
CLFP	California League of Food Processors
CODA	Compliance Offset Developers Association
CPP	Clean Power Plan
CPUC	California Public Utilities Commission
CSCME	Coalition for Sustainable Cement Manufacturing and the Environment
DG	distributed generation
DWR	Department of Water Resources
EA	California Environmental Quality Act Environmental Assessment
EAAC	Economic and Allocation Advisory Committee
EDF	Environmental Defense Fund
EDU	electrical distribution utility
EE	energy efficiency

EGU	Electric Generating Unit
EIM	Energy Imbalance Market
EITE	emissions-intensive, trade-exposed
EJAC	Environmental Justice Advisory Committee
EPA	U.S. Environmental Protection Agency
EPS	California's Emissions Performance Standard
ETS	Emissions Trading Scheme
EV	electric vehicle
EU ETS	European Union Emissions Trading System
FED	Functional Equivalent Document
FERC	Federal Energy Regulatory Commission
FSA	financial services administrator
FSOR	Final Statement of Reasons
GGRF	Greenhouse Gas Reduction Fund
GHG	greenhouse gas
GWP	global warming potential
ICE	Intercontinental Exchange
IEP	Independent Energy Producers Association
IEPR	Integrated Energy Policy Report
IETA	International Emissions Trading Association
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPP	Intermountain Power Plant
IRP	Integrated Resource Plan
ISO	International Organization for Standardization
ISOR	Initial Statement of Reasons
LADWP	Los Angeles Department of Water and Power
LAO	Legislative Analyst's Office
LCFS	Low Carbon Fuel Standard
LNG	liquefied natural gas
LSE	load serving entity
MID	Modesto Irrigation District
MMC	Mine Methane Capture
MRR	Mandatory Reporting of Greenhouse Gas Emissions Regulation
MSW	Municipal Solid Waste
MTCO _{2e}	Metric ton of carbon dioxide equivalent
MMTCO _{2e}	Million metric tons of carbon dioxide equivalent
MWD	Metropolitan Water District
M-S-R	M-S-R Public Powers Agency, an Agreement among Modesto Irrigation District, the City of Santa Clara and the City of Redding
NAICS	North American Industry Classification System
NOV	Notice of Violation
NOVS	Notice of Offset Verification Services
NCPA	Northern California Power Agency
NO _x	oxides of nitrogen
NRDC	Natural Resources Defense Council

NWF	National Wildlife Federation
ODS	ozone depleting substance
OEHHA	Office of Environmental Health and Hazard Assessment
OPDR	Offset Project Data Report
OPO	Offset Project Operator
OSHA	Occupational Health and Safety Administration
PAR	Primary account representative
PCC	Portfolio Content Category, aka "bucket"
PG&E	Pacific Gas and Electric
POU	publicly owned utility
PPA	Power Purchasing Agreement
PSE	Puget Sound Energy
PUC	See CPUC
QE	qualified export
QF	Qualifying Facilities
REC	Renewable Energy Credit
REDD	United Nations Collaborative Programme on Reducing Emissions from Deforestation and Forest Degradation in Developing Countries
RFF	Resources for the Future
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SCG	Southern California Gas Company
SCPPA	Southern California Public Power Authority
SDG&E	San Diego Gas and Electric
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SLCP	Short- Lived Climate Pollutant
SMUD	Sacramento Municipal Utility District
SWP	California State Water Project
TID	Turlock Irrigation District
VAE	voluntarily associated entity
VEA	Valley Electric Association
VRE	voluntary renewable energy
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System
WPTF	Western Power Trading Forum
WSPA	Western States Petroleum Association
WTE	waste-to-energy
ZEV	Zero Emission Vehicle