

**State of California  
Environmental Protection Agency  
AIR RESOURCES BOARD**

**AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF  
GREENHOUSE GAS EMISSIONS**

**FINAL STATEMENT OF REASONS**

**July 2017**

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State of California  
California Environmental Protection Agency  
AIR RESOURCES BOARD

**Final Statement of Reasons for Rulemaking,  
Including Summary of Public Comments and Agency Responses**

PUBLIC HEARING TO CONSIDER PROPOSED AMENDMENTS TO THE  
REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS  
EMISSIONS

Public Hearing Dates: September 22, 2016 and June 29, 2017  
Agenda Item No.: 16-8-3; 17-7-1

**I. GENERAL**

**A. Action Taken in This Rulemaking**

In this rulemaking, the Air Resources Board (ARB or the Board) is adopting amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Regulation or MRR) to ensure the reported GHG data are accurate and fully support the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms (title 17, California Code of Regulations, section 95800 et seq.) (Cap-and-Trade Regulation). Staff is also proposing revisions to ensure the data that are collected for ARB's other climate change programs are complete, accurate, and comply with the U.S. EPA Clean Power Plan.

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). The amendments are codified at Division 3, Chapter 1, Subchapter 10 Climate Change, Article 2, 95101, 95102, 95103, 95104, 95105, 95111, 95112, 95113, 95114, 95115, 95117, 95118, 95119, 95121, 95122, 95124, 95129, 95130, 95131, 95132, 95133, 95150, 95153, 95156, 95157, Appendix A, and Appendix B. Proposed adoption of new sections 95160, 95161, 95162, and 95163, title 17, California Code of Regulations.

The amendments to the Regulation were initiated with the publication of a notice in the California Notice Register on July 19, 2016 and notice of public hearing scheduled for September 22, 2016.<sup>1</sup> A Staff Report: Initial Statement of Reasons, entitled "Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions" (Staff Report or ISOR), the full text of the proposed regulatory amendments,

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<sup>1</sup> California Air Resources Board. Notice of Public Hearing to Consider Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. Posted July 19, 2016. Available online at: <https://www.arb.ca.gov/regact/2016/ghg2016/ghgnotice.pdf>

references, and other supporting documentation were made available for public review. The regulatory amendments as proposed would:

- Support California's Cap-and-Trade Regulation by requiring further information to ensure consistency with allocation and the calculation of compliance obligations.
- Ensure that reported GHG emissions data are accurate and complete in order to support California's GHG reduction programs, including the statewide GHG emissions inventory.
- Ensure full accounting of emissions from electricity imports within the Energy Imbalance Market (EIM).
- Include reporting requirements for electricity generating facilities to implement the U.S. EPA Clean Power Plan.
- Revise the annual verification deadline from September 1 to August 10, which is needed to support implementation of the Cap-and-Trade program requirements.

At its initial September 22, 2016 public hearing, the Board was informed of proposed amendments to MRR. The Board did not take action on the proposal at the September 2016 board Hearing, but directed staff to make additional 15-day changes to MRR as appropriate as part of a subsequent 15-day notice to the rulemaking package.

During the initial comment period and the subsequent 15-day public comment periods, the public submitted comments on the proposed amendments.<sup>2</sup> The 45-day comment period commenced on July 22, 2016, and ended on September 19, 2016, with additional oral and written comments submitted at the September 22, 2016 Board hearing. The first 15-day comment period occurred from December 21, 2016 to January 20, 2017. The second 15-day comment period occurred from April 13, 2017 to April 28, 2017.

At a second public hearing held on June 29, 2017, the Board approved Resolution 17-20<sup>3</sup>, adopting the proposed regulatory amendments, with a small number of modifications proposed by staff in Attachment B to the Resolution. 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 and oral comments given at the Board hearing on September 22, 2016, June 29, 2017.

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<sup>2</sup> All public comments received on the proposed amendments can be found online at: <https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=ghg2016>

<sup>3</sup> California Air Resources Board. Board Resolution 17-20. Available online at: <https://www.arb.ca.gov/regact/2016/ghg2016/ghg2016.htm>

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

The Board has determined that this regulatory action will not result in a mandate to any local agency or school district, the costs of which are reimbursable by the state pursuant to Part 7 (commencing with section 17500), Division 4, Title 2 of the Government Code. The Board has also determined that this regulatory action will not create additional costs or impose a mandate upon any local agency or school district, whether or not it is reimbursable by the State pursuant to Part 7 (commencing with section 17500), Division 4, Title 2 of the Government Code. Although some government agencies may be affected, they are affected only because they are subject to a generally applicable rule for all similarly-situated reporters; there is no specific mandate to local government. Accordingly, there is no mandate for purposes of the Government Code.

Specifically, some public local government agencies are affected by the updates to the Mandatory Reporting Regulation. The five local entities that operate affected power plants are estimated to have a combined cost increase of \$1,402 over eight-years to make minor changes in how their GHG data are reported for the first year that the updates take effect. The nine local government electric power entities affected by the changes are estimated to incur an additional net combined cost of approximately \$6,496 over eight-years to comply with the proposed revisions, which include some minor cost savings.

Staff evaluated small business applicability based on reporting requirements from the years 2012 to 2015. After a thorough evaluation of the reported data, staff determined that there are no small businesses subject to this Regulation in California.

## **C. Consideration of Alternatives to the Proposed Amendments**

Staff is required to consider alternatives to the proposed amendments for the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, including the option of performance standards. For the reasons set forth in the Staff Report, in staff's comments and responses to comments at the Board hearing, and in this FSOR, the Board determined that no alternative considered by the agency would be more effective in carrying out the goals of AB 32, or would be as effective as 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 AB 32 goals 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 II.D. of the Staff Report for the proposed amendments.

## **II. MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL**

### **A. Modifications Approved at the Board Hearing and Provided for in the 15-Day Comment Periods**

Pursuant to Board direction provided at the September 22, 2016 meeting, ARB released Notices of Public Availability of Modified Text and Availability of Additional Documents and Information (15-Day Notices) on December 21, 2016, and April 13, 2017, which placed documents into the regulatory record and presented additional modifications to the regulatory text after consultation with stakeholders.<sup>4</sup>

### **B. Non-Substantive Corrections to the Regulation and Documents**

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

1. For the Initial Statement of Reasons released on July 19, 2016, the following reference was cited: CPP 2015. Clean Power Plan Final Rule. Subpart UUUU—Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units; 40 CFR Part 60, Subpart UUUU (October 23, 2015 Edition, pages 64661-65120). <http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf> (accessed 3/24/2016). Although the Federal Register title page cites pages 65661-65120, the document posted at the link provided only includes pages 64661-64964. This is the complete document desired for the MRR rulemaking and there appears to be an error in the Federal Register title page for the document.
2. In the second fifteen-day notice the following incorporated by reference document was cited: Pistachios In the Shell, Shipping Point and Market Inspection Instructions, U.S. Department of Agriculture, April 2005. The correct document date is February 2005. The correct document was provided to the rulemaking file, the error only exists in the fifteen-day notice citation.
3. A typographical error was identified by staff in section 95131(b)(14) of the Regulation. In the section, there is a reference to section 95113(l)(5), which no longer exists in the Regulation text. The correct reference is to section 95113(l)(3). The error occurred because the numbering in section 95113(l) was updated when sections were deleted, but the update was not correctly reflected in the text added to section 95131(b)(14). In addition, a typographical error was corrected in the section, adding the word “to” to the following phrase: “...throughputs reported by refineries pursuant to section 95113(l)(3) that are used to calculate...”. These corrections have been reflected in the Final Regulation Order.

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<sup>4</sup> California Air Resources Board. Notice of Public Availability of Modified Text and Availability of Additional Documents. Posted December 21, 2016 and April 13, 2017. Available online at: <https://www.arb.ca.gov/regact/2016/ghg2016/ghg2016.htm>

4. In the initially proposed 45-day revisions, the spelling corrections to the word “calyces” in the definition for “Whole tomatoes” in section 95102(b) was incorrectly formatted. It was displayed as: “caliycies” in the 45-day revisions, and should be displayed as “caliycies” to reflect the intended revision and the correct spelling. This is reflected in the Final Regulation Order.
5. In section 95103(m)(3), certain text was stricken as part of the originally proposed 45-day revisions. Under the first 15-day comment period, the stricken text was subsequently underlined. This was a formatting error, and the text should be displayed as only strikeout. Specifically, in the regulation text released under the 15-day notices, the text, “...apply to the start of athe subsequent data year, except in the circumstances described...”, is correctly formatted as, “...apply to the start of ~~athe subsequent~~ data year, except in the circumstances described...”. This formatting error has been corrected in the Final Regulation Order.
6. In section 95102(b), the definition for “Rare earth elements” was inadvertently duplicated, so the duplication was removed from the Final Regulation Order. In addition, the pre-existing definition for “Recycled” in the official California Code of Regulations was inadvertently deleted from the regulation package, so it has been restored in the Final Regulation order.
7. In section 95103(h)(2), in the second 15-day revisions, the text, “2018, and for each subsequent year.” is shown as not being underlined. The text was added in the 45-day revisions and should have been displayed as new text, with underline formatting, in the second 15-day changes.
8. In the first sentence of section 95121(d)(2), the word, “racks” was deleted to make the sentence grammatically correct. The updated text now reads: “California position holders that are also terminal operators and refiners-racks must report the annual quantity in barrels delivered...”.

The above described modifications constitute non-substantial changes to the regulatory text because it more accurately reflects the correct applicability of the provision, but does not materially alter the requirements, rights, responsibilities, conditions, or prescriptions contained in the Regulation.

### **III. DOCUMENTS INCORPORATED BY REFERENCE**

The Regulation adopted by the Executive Officer incorporate by reference the following documents. 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. The documents are lengthy and 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.



“Inspection Procedures” for Soluble Solids Testing – Digital Refractometer, as published by the Processing Tomato Advisory Board (PTAB), 2014.

The following portions of U.S. EPA Clean Power Plan Final Rule. Subpart UUUU—Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units; 40 Code of Federal Regulations (CFR) Part 60, Subpart UUUU: 40 CFR sections 60.5845, 60.5850, 60.5860, and 60.5880, published in the Federal Register on October 23, 2015 (accessed 3/24/2016).

U.S. EPA Standards of Performance for New Stationary Sources, 40 Code of Federal Regulations (CFR) Part 60, Subpart A, Section 60.7. July 1, 2012.

Monthly Refinery Report Instructions for Form EIA-810, U.S. Energy Information Administration, OMB No. 1905-0165, Revised 2013.

Glossary, U.S. Energy Information Administration, website (accessed 05/27/2016).

American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 11 – Physical Properties Data. May 2004.

American Society of Testing and Materials Standard Guide for Use of the Petroleum Measurement Tables, ASTM D1250-08. Reapproved 2013.

American Petroleum Institute Technical Data Book – Petroleum Refining, Sixth Edition, April 1997.

Table A-1 to Subpart A of Title 40 Code of Federal Regulations (CFR) Part 98, as published to the CFR on 12/11/2014. U.S. EPA Mandatory Greenhouse Gas Reporting.

ASTM D-70-09. Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method). 2009.

ASTM D-287-92. Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method). Reapproved 2000.

ASTM D-1945-03. Standard Test Method for Analysis of Natural Gas by Gas Chromatography. Reapproved 2010.

ASTM D-3588-98. Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels. Reapproved 2003.

ASTM D-4052-09 Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter. 2009.

ASTM D-5002-16 Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer. 2016.

EPA Method 8021B Aromatic and Halogenated Volatiles by Gas Chromatography Using Photoionization and/or Electrolytic Conductivity Detectors. 2014.

EPA Method 8260B Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS). 1996.

EPA Method TO-14A Determination of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters with Subsequent Analysis By Gas

Chromatography. 1999.

EPA Method TO-15 Determination of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters and Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS). 1999.

GPA 2174-93 Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography. 2000.

GPA 2177-03 Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography. 2003.

GPA 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography. 2000.

GPA 2286-95 Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography. Reprinted 1999.

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

ASTM D-7096-16. Standard Test Method for Determination of the Boiling Point Range Distribution of Gasoline by Wide Bore Capillary Gas Chromatography, 2016.

Pistachios In the Shell, Shipping Point and Market Inspection Instructions, U.S. Department of Agriculture, February 2005.\*

In the interest of completeness, staff has also added the following documents to the rulemaking file, which were provided during the first 15-day comment period:

California Independent System Operator, "Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal," November 17, 2016. Accessed Dec 1, 2016:

Air Resources Board, "Analysis of the Energy Imbalance Market and Mandatory Greenhouse Gas Reporting and Cap-and-Trade Regulations," December 21, 2016. *Attached to the First 15-day Notice as Attachment B.*

#### **IV. SUMMARY OF COMMENTS MADE DURING THE 45-DAY COMMENT PERIOD 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 July 22, 2016, and ended on September 19, 2016, with additional comments submitted at the September 22, 2016 Board hearing on the proposed amendments.

ARB received 37 letters on the proposed amendments during the 45-day comment period or at the Board hearing. In addition, 17 commenters gave oral testimony at the

September 2016 Board hearing. Commenters included representatives from the electricity and natural gas sectors, oil and natural gas extraction and refining sectors, and other reporters and verifiers. To facilitate the 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.

The individually submitted comment letters for the 45-day and 15-day comment periods are available here: <https://www.arb.ca.gov/regact/2016/ghg2016/ghg2016.htm>

This rulemaking is for amendments to the ARB Greenhouse Gas Mandatory Reporting Regulation. However, comments were also submitted to this rulemaking which relate to the separately noticed Cap-and-Trade program rulemaking, which is outside the scope of the proposals identified in the Staff Report, Notices of Modified Regulatory Text, and this FSOR. Statute only requires responses to comments directly submitted as part of a specific rulemaking, and this FSOR provides responsive comments only to those comments related to this specific rulemaking.

Note that some comments 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/ghg2016/ghg2016.htm>. Transcripts for any verbal testimony presented during the first Board hearing is available here: <https://www.arb.ca.gov/board/mt/2016/mt092216.pdf>

## A. LIST OF COMMENTERS

**Table IV-1**

<b>Abbreviation</b>	<b>Commenter</b>
CTAM1	Chuck Tamagni Written Testimony: 8/29/2016
PWX1	Nicolas Van Aelstyn, Powerex Corp Written Testimony: 9/9/2016
AES1	Erin Quinn, Analytical Environmental Services Written Testimony: 9/12/2016
AMGAS1	Drinker Biddle & Reath LLP, AmeriGas Propane, L.P. Written Testimony: 9/12/2016
LRQA1	Derek Markhof, Lloyd's Register LRQA Written Testimony: 9/16/2016
CE1	Clay Harrison, Clean Energy Written Testimony: 9/16/2016
SDGE1	Andrianna Kripke, San Diego Gas & Electric Written Testimony: 9/19/2016
CAISO1	Andrew Ulmer, California Independent System Operator Written Testimony: 9/19/2016
BROOK1	Steve Zuretti, Brookfield Energy Marketing LP Written Testimony: 9/19/2016
CCMEC1	Frank Sheets, California Cement Manufacturing Environmental Consortium Written Testimony: 9/19/2016
SAPUTO1	Nicholas Martin, Saputo cheese USA Inc. Written Testimony: 9/19/2016
SIMP1	David Huck, J.R. Simplot Company Written Testimony: 9/19/2016
PALOALTO1	James S. Allen, City of Palo Alto Written Testimony: 9/19/2016
PGE1	Mark Krause, Pacific Gas and Electric Company Written Testimony: 9/19/2016
CALPINE1	Barbara McBride, Calpine Corporation Written Testimony: 9/19/2016

<b>Abbreviation</b>	<b>Commenter</b>
MWDSC1	Jeffrey Kightlinger, The Metropolitan Water District of Southern California Written Testimony: 9/19/2016
FE1	Jay Wintergreen, First Environment, Inc. Written Testimony: 9/19/2016
SC1	Travis Ritchie, Sierra Club Environmental Law Program Written Testimony: 9/19/2016
WPTF1	Clare Breidenich, Western Power Trading Forum Written Testimony: 9/19/2016
CALCHAMBER1	Amy Mmagu , California Chamber of Commerce Written Testimony: 9/16/2016
TID1	Ken R. Nold, Turlock Irrigation District Written Testimony: 9/19/2016
CCA1	C.C. Song, Community Choice Aggregators Written Statement 9/19/2016
FWW1	Rebecca Claassen, Food & Water Watch Written Testimony: 9/19/2016
SCE1	Dawn Wilson, Southern California Edison Written Testimony: 9/14/2016
CCEEB1	Gerald D. Secundy, California Council for Environmental and Economic Balance Written Testimony: 9/19/2016
CASA1	Sarah A. Deslauriers, California Association of Sanitation Agencies Written Testimony: 9/19/2016
SMUD1	William Westerfield, Sacramento Municipal Utility District Written Testimony: 9/19/2016
ORA1	Julie Halligan, Office of Ratepayer Advocates, California Public Utilities Commission Written Testimony: 9/19/2016
AP1	Keith Adams, Air Products and Chemicals Written Testimony: 9/19/2016
LADWP1	Mark Sedlacek, Los Angeles Department of Water & Power Written Statement: 9/19/2016

<b>Abbreviation</b>	<b>Commenter</b>
WSPA1	Catherine Reheis-Boyd, Western States Petroleum Association Written Testimony: 9/19/2016
MID1	Gary Soiseth, Modesto Irrigation District Written Testimony: 9/19/2016
MID2	Gary Soiseth, Modesto Irrigation District Written Testimony: 9/19/2016
VEA1	Ellen Wolfe, Valley Electric Association, Inc. Written Testimony: 9/19/2016
SOCALGAS1	Tim Carmichael, Southern California Gas Company Written Testimony: 9/19/2016
CCPC1	Shelly Sullivan, Climate Change Policy Coalition Written Testimony: 9/19/2016
MSR1	Susie Berlin, MSR Public Power Agency Written Testimony: 9/21/2016
WSPA2	Western States Petroleum Association Written Testimony: 9/22/2016
CCPC2	Shelly Sullivan, Climate Change Policy Coalition Verbal Testimony: 9/22/2016
MSR-NCPA1	Susie Berlin, MSR Public Power Agency & Northern California Power Agency Verbal Testimony: 9/22/2016
FE2	Jay Wintergreen, First Environment Verbal Testimony: 9/22/2016
PGE2	Nathan Bengtsson, Pacific Gas & Electric Verbal Testimony: 9/22/2016
CHEV1	Steve Arita, Chevron Verbal Testimony: 9/22/2016
AGR1	Paul Spitzer, Avan Grid Renewables Verbal Testimony: 9/22/2016
WSPA3	Tiffany Roberts, Western States Petroleum Association Verbal Testimony: 9/22/2016
SMUD2	Timothy Tutt, Sacramento Municipal Utility district Verbal Testimony: 9/22/2016

<b>Abbreviation</b>	<b>Commenter</b>
LADWP2	Cindy Parsons, Los Angeles Department of Water and Power Verbal Testimony: 9/22/2016
MID3	Sean Neal, Modesto Irrigation District Verbal Testimony: 9/22/2016
CLFP1	John Larrea, California League of Food Processors Verbal Testimony: 9/22/2016
SCPPA1	Sarah Taheri, Southern California Public Power Authority Verbal Testimony: 9/22/2016
SVP1	Kathleen Hughes, Silicon Valley Power Verbal Testimony: 9/22/2016
TID2	Brian Biering, Turlock Irrigation District Verbal Testimony: 9/22/2016
CCEEB2	Mik Skvarla, California Council for Environmental and Economic Balance Verbal Testimony: 9/22/2016
CMUA1	Dan Griffiths, California Municipal Utilities Association Verbal Testimony: 9/22/2016
CE2	Todd Campbell, Clean Energy Verbal Testimony: 9/22/2016

## **B. General Reporting Regulation Comments**

### **B-1. Multiple Comments: *Alignment of the MRR with EPA***

**Comment:** The City of Palo Alto recommends further action be taken within the proposed amendments to better align the California Air Resources Board's (CARB) GHG reporting regulation with that of the United States Environmental Protection Agency's (USEPA).

The City of Palo Alto treats wastewater collected from 220,000 residents of Palo Alto, Stanford University, Mountain View, Los Altos, Los Altos Hills, and the East Palo Alto Sanitary District. The City of Palo Alto treatment plant utilizes several stationary combustion sources that require facility reporting of GHG emissions under the existing Regulation for the Mandatory Reporting of Greenhouse Gas Emissions as well as reporting under the USEPA's Mandatory Greenhouse Gas Reporting regulation (40 CFR §98). Currently, the CARB GHG regulation utilizes global warming potentials and emission factors from 2009-2011 versions of the USEPA regulation; however, USEPA has since amended these values resulting in significantly different emission inventories

for the same facility being reported to the two regulatory agencies. This discrepancy results in increased staff time for inventory compilation as well as confusion for those not directly involved in emission compilation and reporting such as elected officials, upper management, and interested public stakeholders. The proposed amendments to the CARB regulation seek to align global warming potential multipliers with that of the USEPA regulation by incorporating as reference Table A-1 to Subpart A of the Title 40 Code of Federal Regulations Part 98, as published to the CFR on 12/11/14. However, the proposed amendments do not currently seek to adopt the most recent USEPA emission factors resulting in facilities, such as the City of Palo Alto, still having significantly different emission inventories reported to the two different regulatory agencies. City of Palo Alto recommends that CARB also align emission factor multipliers with that of the USEPA regulation by incorporating as reference Tables C-1 and C-2 to Subpart C of the Title 40 Code of Federal Regulations Part 98, as published to the CFR on 12/11/14. (PALOALTO1)

**Comment:** The language under §95100(c) of the Reporting Regulation (February 2015) requires that provisions of 40 CFR Part 98 be incorporated, which represent a portion of the U.S. Environmental Protection Agency's (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases (U.S. EPA's Final Rule). The section states:

"Unless otherwise specified, references in this article to 40 CFR Part 98 are to those requirements promulgated by U.S. EPA and published in the Federal Register on October 30, 2009, July 12, 2010, September 22, 2010, October 28, 2010, November 30, 2010, December 17, 2010, and April 25, 2011."

Revisions have been made to the Reporting Regulation since 2012 (when the cap-and-trade program became effective) with the intent of aligning it with the U.S. EPA's Final Rule. However, the proposed amendments have not included an update to the above statement or any discussion in the ISOR on when to use post 2011 versions of 40 CFR Part 98. The ISOR does state that ARB staff proposes altering the global warming potential values - to move from the Second Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) values to the Fourth Assessment Report of the IPCC values beginning with 2021 data reported in 2022, as specified in the latest published versions of U.S. EPA's Final Rule. We recommend adding a similar statement to the ISOR clarifying when, for example, emission factors defined in Tables C-1 and C-2 in later published versions of 40 CFR Part 98 (i.e., post 2011) are expected to be referenced in ARB's Reporting Regulation. This is important for agencies that want to manage their greenhouse gas emissions to remain below reporting and/or cap-and-trade thresholds. (CASA1)

**Response:** The change for emissions factors was not incorporated in the proposed revisions or included in the notice of changes, so it is out of scope and we are unable to make the revision at this time. CARB does not always maintain ongoing consistency with the EPA regulation in order to provide consistency and predictability in our own programs and regulations. Staff will work with interested parties on future rulemakings to align emissions factors with EPA regulations. In



2021, the MRR reporting will shift to using the 4<sup>th</sup> assessment GWP values as the caps in the Cap-and-Trade Program are proposed to be set using the 4<sup>th</sup> assessment GWP values. Currently, the caps in the Cap-and-Trade Program use the 2<sup>nd</sup> assessment GWPS through 2020 and MRR data must be collected using the same GWP values to ensure consistency within the Cap-and-Trade Program.

**B-2. Comment: *Section 95102(a) Carbon Sequestration Definition***

We recommend that the definition of geological sequestration in Section 95102(a)223 be the one used by the USEPA. “Geologic sequestration is the process of injecting carbon dioxide, captured from an industrial (e.g., steel and cement production) or energy-related source (e.g., a power plant or natural gas processing facility), into deep subsurface rock formations for long-term storage.” (<https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2>). (WSPA1)

**Response:** The proposed definition added to MRR matches the definition for geologic sequestration used within the Cap-and-Trade Regulation. Therefore, staff retained the proposed addition of the definition for consistency. In addition, the EPA and ARB definitions are substantially equivalent, except that the EPA definition is slightly more limited in the scope of what is classified as geologic sequestration.

**B-3. Comment: *Section 95102(a)(107) Correctable Errors Definition***

PG&E commends ARB for proposing this amendment which supports accurate reporting for Cap-and-Trade -related data but allows for more flexibility for those data that are not subject to the Cap-and-Trade program. (PGE1)

**Response:** Staff appreciates support for the change.

**B-4. Comment: *Section 95102(a) Pipeline Quality Natural Gas Definition***

In the Proposed Regulation Section 95102, Definitions, the definition of “Pipeline Quality Natural Gas,” specified for use in calculating emissions under this article, is stipulated as “natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.” SoCalGas has previously provided written comments<sup>1</sup> regarding the definition of this term and its use in the MRR regulation.

<sup>1</sup> SoCalGas and SDG&E comment letters of September 27, 2011, July 10, 2013, and October 23, 2013

The California Public Utility Commission (CPUC) establishes natural gas specifications that utilities must adhere to for purposes of receiving, transporting and delivering natural gas to their customers. Therefore, SoCalGas believes that the Air Resources Board (ARB) should make sure that all definitions used in your regulations for natural gas

regulated by the CPUC, are consistent with the CPUC's regulations and orders on the same or closely related subject matter, such as

General Order 58A – Standards for Gas Service in the State of California, 58B – Heating Value Measurement Standard for Gaseous Fuels, and all California natural gas utility tariffs regarding quality and content of natural gas such as SoCalGas Rule No. 30 – Transportation of Customer-Owned Gas.

The word “quality” in the definition of “Pipeline Quality Natural Gas” in §95102 is used in the context of defining a default “range” for purposes of MRR calculations. The word “quality” implies a standard or grade that has an intrinsic value, characteristic or feature. In many cases the word “quality” is used to imply excellence or grade and convey a positive connotation, whereas anything that is not labeled with the word “quality” creates a negative connotation. The use of the word “quality” could be construed as implying that gas that meets pipeline specifications is nevertheless not “pipeline quality.” SoCalGas specifically takes issue with ARB making up their own definition for pipeline quality natural gas that appears inconsistent with the CPUC's standards for pipeline quality gas, and would exclude some natural gas accepted into our pipeline system from local producers, as required by the CPUC.

In the interest of clarity, and to avoid any potential for encroachment into areas committed to the exclusive regulatory jurisdiction of the CPUC, we recommend that ARB select a different term than “quality” for purposes of defining the “default range” for the calculations and reporting required under the proposed amendments to this regulation. For example, refineries may use non-CPUC regulated refinery gas; such that ARB could then define refinery gas different from the natural gas supplied to customers by CPUC regulated gas utilities.

While the CPUC requires natural gas utilities to use representative higher heating value for billing purposes (see <https://www.socalgas.com/pay-bill/understanding-your-bill/btu> for more information as to Btu districts and billing factors and CPUC General Order No. 58A, 6. Heating Value of Gas, December 1992), there is not a similar requirement for methane content, thus SoCalGas doesn't necessarily have data for delivered natural gas to individual customers as to the methane content of gas. Further, we understand that the methane content portion of the definition for pipeline natural gas originated with U.S. EPA, which wrote it decades ago and is no longer using it for GHG reporting (see definitions in §98.6 of 40 CFR Part 98 Mandatory Reporting of Greenhouse Gases, Subpart A General Provisions). Additionally, we could not find a case in the existing or proposed amended regulation where percent methane content changes the calculation methodology that one must use to report. (SOCALGAS1)

**Response:** The provided comments are out of scope for this rulemaking, because the modifications discussed in the comment were not incorporated in the proposed revisions or included in the notice of changes. However, staff would like to clarify that the use of the word “quality” in the definition of “Pipeline Quality Natural Gas” is not intended to be interpreted as a statement on the

intrinsic value or “grade” of the natural gas products that are delivered through natural gas transmission and distribution systems. The purpose of the referenced definition is to provide the chemical composition and heat content boundaries where the natural gas default emission factor is applicable for calculating emissions. The definition is not intended to replace or interfere with the quality and content requirements imposed by the California Public Utility Commission (CPUC) that privately owned natural gas utilities must adhere to. Furthermore, regarding the prescribed methane content requirements contained in the referenced definition, MRR does not specifically require reporters that are combusting utility delivered natural gas to analyze or maintain records of the methane content of the combusted natural gas. It is reasonable for reporters to assume (for reporting purposes) that the average methane content for utility delivered natural gas meets the criteria provided in the definition of pipeline quality natural gas.

**B-5. Comment: *Section 95103(k)(6) Calibration Frequency***

Air Products strongly support the concept that extends the calibration frequency for differential pressure measurement devices used by facilities which operate continuously with infrequent outages. In such instances, the removal of an orifice plate to allow verification of the orifice diameter often requires taking that process line out of service. When on a critical process feed, product or recycle line, this requires an entire process shutdown. ARB has recognized this and offered, under the proposed revision to §95103(k)(6)(A)(1), an extension to six years recalibration frequency for such devices used in a refinery. Air Products hydrogen plants are integrally linked with refineries, operate continuously, and infrequently have maintenance outages. In fact, our hydrogen plant outages are closely coordinated with our refinery customers to coincide with their outages to minimize such operating interruptions (and the negative environmental impacts of an un-needed shut-down/start-up cycle). Air Products strongly requests this same calibration frequency extension be offered to hydrogen plants, as well. (AP1)

**Response:** Staff agrees with the comment and has provided the six-year calibration and inspection frequency time extension to both refineries and hydrogen plants.

**B-6. Comment: *Section 95103(k)(6) Pressure Differential Device Calibration***

ARB proposes amending Section 95103(k)(6)(A)(1) to: “Pressure differential devices must be inspected at a frequency specified in paragraph (k)(4) of this section, unless the device is located at a refinery that operates continuously with infrequent outages. In such cases, the owner or operator of the refinery must inspect each device at a frequency of at least once every six years”. This is directionally a positive change that appropriately recognizes the reality of infrequent outages. That being said, infrequent outages can be longer than six years. The EPA MRR (40 CFR 98.34(b)(1)(v)) allows the refinery to align the inspections with a schedule consistent with planned shutdowns.

WSPA supports adoption of the ARB-proposed amendment, but further recommends that the language be revised to read “In such cases, the owner or operator of the refinery must inspect each device at least once every six years or during the next scheduled maintenance outage.”  
(WSPA1)

**Response:** Staff recognizes the efforts refinery operators make to ensure accurate data is being reported to ARB on an annual basis. MRR, which generates data used for the Cap-and-Trade Program as there is a monetization of the emissions, requires a greater degree of accuracy, and a higher level of confidence that reported data is accurate than EPA’s GHG reporting program. ARB has determined that meter inspections are an essential step for refinery operators to provide evidence of accuracy for both emissions and product data. Delaying inspections beyond six years, or even a potentially indefinite time period, is inconsistent with a robust GHG reporting program. For additional background, the following is provided from the 2010 MRR Initial Statement of Reasons (ISOR)<sup>5</sup>.

“Rationale for Section 95103(k). This provision is similar to requirements in the current ARB reporting regulation, but applies the U.S. EPA language with slight modification. To support cap-and-trade, it is necessary to ensure that measurements associated with determining GHG emissions be highly accurate. Although the current ARB and U.S. EPA rules share the requirement for fuel measurements to be 95 percent accurate, a provision in the U.S. EPA rule could result in indefinite delays in the calibration of measurement equipment. The additional provision to provide notification and review of delays in calibration of measurement devices is intended to keep ARB staff informed of equipment that has not been calibrated, and provide either a schedule for completing equipment calibration or a demonstration calibration is not needed, if applicable. This provision is necessary to ensure that ARB is aware of such delays, and if a pattern of delay develops, that the Executive Officer is able to direct that calibrations be carried out.”

#### **B-7. Comment: *Section 95103(m) Methodology Change Requirements***

We are concerned by the proposed changes to 95103(m), specifically those that relate to product data calculations and monitoring. As currently written, the proposed changes could be interpreted to mean that ANY changes to product data calculations or monitoring (including installing better meter technology, using financial data, etc.) would require ARB approval. This could trigger the submittal of a large number of alternate methods to ARB, creating a large backlog as has occurred with meter postponement requests. Historically postponement requests have taken 1 year to process, and that would be unacceptable for product data that is reported annually to ARB. In fact, any

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<sup>5</sup> Staff Report: Initial Statement of Reasons for Rulemaking. Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32). October 28, 2010. <https://www.arb.ca.gov/regact/2010/ghg2010/ghgisor.pdf>

delays in the processing of these alternate methods for product data will cause facilities to reconsider any improvements/changes to their product data, reducing the overall accuracy of the data. A facility may not want to implement any changes, even if it leads to more accurate/reliable data, due to the delays created by the new ARB approval process. WSPA recommends that ARB delete all of the changes made to sections 95103(m)(1) through (3) to avoid affecting the quality of covered product data. (WSPA1)

**Response:** It is important that ARB receives notification of product data method changes, and approves changes because the covered product data is used for Cap-and-Trade allowance allocations. The proposed changes clarify the current requirements for notifying ARB and obtaining approval of permanent changes and alternative measurement methods. The changes clarify that operators must provide notification and obtain approval for permanent changes to all “monitoring or calculation methods” used for reporting covered product data. As currently implemented, and stated in ARB’s guidance document<sup>6</sup>, notification and/or approval is not required for changes, updates, or improvements solely to the instrumentation used to gather data, as long as the measurement and quantification methodology remains consistent. The notification and approval requirements apply to a true change in method, in which there are changes to the quantification methodology used to quantify the product data. For virtually any industry sector, product data quantification methods are firmly established, and are unlikely to change from year to year. Based on current experience with implementing the program, we expect permanent changes in product data methods to be uncommon. In addition, the proposed changes do not affect the previous timing of notifications and approvals, and many approval delays in the past have been a result of obtaining incomplete notification submissions by reporters, which require additional follow-up and time by ARB staff to complete. Note that these proposed changes affect “changes to methodologies” and not requests for “postponement of calibration,” which is cited by the commenter and is an entirely separate mechanism that provides flexibility to operators that cannot calibrate or inspect their meters at the frequency required by section 95103(k)(4).

#### **B-8. Comment: *Section 95104(f) Emissions Changes at Facilities***

If operators determine that there are changes in emissions, this section requires that a “narrative” be submitted to describe what caused the changes. CCMEC considers that a clarification is necessary to provide guidance as to what constitutes a “change” in emissions. In addition, because over 50 percent of cement plant emissions are from the process itself, such emissions are virtually always subject to variances of more than 5 percent based solely on supply and demand. For this reason, CCMEC proposes that CARB consider including a box to check for “Market Demand” or other commonly used explanations for the “change” in emissions. Furthermore, guidance is necessary to

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<sup>6</sup> Measurement Accuracy and Missing Data Provisions for California’s Mandatory Greenhouse Gas Reporting Regulation, 2/17/2017. <https://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/accuracy-missingdata.pdf>

help facilities decide which emissions to consider when making this determination: (1) the facility's total emissions or (2) emissions after biogenic and de minimis emissions are deducted. (CCMEC1)

**Response:** Staff modified the original text because the use of check-boxes or simple yes/no responses was not considered sufficiently adequate to support ARB program needs. Therefore, the updated requirements specify that a narrative description of the changes must be provided. However, in response to the comment, staff modified the requirement to clarify that only a "brief" narrative is required, and it must only be provided if there was a change of more than  $\pm 5$  percent from the prior year emissions. We also clarified that the narrative description is not subject to third-party verification requirements. The current and proposed Regulation text requires that the reason for changes be reported if the "emissions of greenhouse gases" change by more than five percent in relation to the previous reporting year. In this context, "emissions of greenhouse gases" refers to the total emissions of all greenhouse gases, which includes covered and exempt emissions, biogenic, de minimis, process, vented, fugitive, or any other emissions produced and reported for a calendar year. For clarity, staff intends to include additional descriptive information in the Cal e-GGRT reporting tool.

**B-9. Comment: *Section 95104(f) Verification of Emissions Changes at Facilities***

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 (e.g., impacts of catalyst selection or operational temperature on formation of N<sub>2</sub>O 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. (SIMP1)

**Response:** In response to this comment, staff modified the Regulation language to make it explicit that the narrative description is not subject to the third-party verification requirements.

**B-10. Multiple Comments: *Section 95105(b) ARB Requests for Records***

**Comment:** PG&E recognize ARB staff's goal for timely responses to requests. Although we agree that a 10 day response period is reasonable, we believe that this should be ten working days, not calendar days, and include a provision for the Executive Officer or designee to grant an extension, if reasonable. MRR reporters represent the largest GHG emission sources in the state, and a majority of them are subject to the Cap-and-Trade regulation. It is therefore in the reporter's best interest to be responsive to ARB requests as the potential impacts under MRR are outweighed by the potential impacts from non-compliance with the Cap-and-Trade regulation. (PGE1)

**Comment:** This section reduces the response time to a CARB Request for Records from 20 days to 10 days. Considering the limited staff available to respond to such requests, only providing 10 days to respond is highly problematic and overly burdensome and will cause potential disruptions in normal operations. CCMEC requests that the response time remain 20 days. Alternatively, CCMEC recommends that CARB insert language to allow flexibility for discussion of an alternative agreement acceptable to both parties. In addition, the rule does not specify whether the 10 or 20 days are business days or calendar days. CCMEC recommends that CARB revise this section to clarify that the 10 or 20 days are business days. (CCMEC1)

**Comment:** Staff has modified section 95105(b) to require that reporting entities respond to requests for records by CARB within 10 days of receipt of the request. WPTF requests that CARB modify this provision to provide for 10 business days after request. 10 calendar days would not provide sufficient time for reporting entities to gather requested information. (WPTF1)

**Comment.** Further, in 95105(b), the response time allotted to facilities to fulfill ARB's requests for any MRR-related records was shortened from twenty days to ten days. The examples of data that may be requested was proposed as, "This includes, but is not limited to, information used to quantify or report emissions and product data in the emissions data report, underlying monitoring and metering data, invoices of receipts or deliveries, sales transaction data, calculation methods, protocols used, analysis results, calibration records, electricity transaction data, and other relevant information." The list of information is extensive and housed in many different departments of the business.

Ten working days does not allow adequate time for the data reporter for the facility to communicate with the owners of all the relevant documents, and, review and submit. Much of the information (e.g., a copy of a specific invoice) requires coordinating with other staff that may not be available within ten days given weekends, holidays, and out-of-office days during the normal course of business.

As the existing response time was marginally sufficient, WSPA requests that ARB retain the existing language or, alternatively, replace "20 working days" with "21 days" which is effectively a week shorter than the existing language but much more reasonable than the proposed language. ARB could also add the caveat "unless otherwise specified by ARB" after the "20 working days" (or alternatively, "21 days") as it has done in the Cap & Trade regulation language. (WSPA1)

**Comment:** Lastly, and if I've got time here, in general, WSPA recommends that ARB be consistent in its use of deadlines by using quote unquote working days instead of calendar days. Currently, there's a mix of both of those terms, and there's been concern from ARB staff that working days may not be a term consistently interpreted by reporters and verification bodies. That can simply be resolved with the definition. And so the definition for working days would be defined as days of the week, excluding weekends and national and State holidays. (WSPA3)

**Comment.** Also on calendar items, staff has proposed reducing the time limit to respond to data requests by over 75 percent. That's from 20 days to 5 days. And this unduly increases the risk of a violation resulting from untimely responses. We suggest at least a 10-business day response time be considered. Again, these things just take time. (PGE2)

**Comment:** The reporting deadlines in Section § 95131.c.5 and § 95131.f and § 95131.g should be based on “working” days. There are number of places in these proposed amendments where reporting deadlines have been shortened. Reporting requires significant quality control and internal approvals, and ensuring there is time to get it right is a priority for SCE. A focus on “working days” would still allow for a timely response to ARB, but ensure that SCE would have the time to ensure the data it is reporting attains the standard of excellence we strive for. (SCE1)

**Response:** Based on the comments, staff changed the requirement to “14 days” (14 calendar days) allowing additional time for reporters to respond, while also meeting ARB needs to obtain data more quickly. Staff also added the text, “unless a different schedule is agreed to by ARB.” This revision provides flexibility for reporters to request additional time in situations where there are complex data requests or the reporter has justification for not meeting the 14-day response requirement. Regarding the WSPA comment, staff has implemented a consistent use of referring to days to respond. In general, staff made updates to the Regulation to refer to the total number of calendar days required to respond, and removed nearly all references to “working” days. This removes the ambiguity in interpreting what a “working” day is, and focuses strictly on calendar days. As appropriate, the number of days to respond has been updated to reflect the change to calendar days.

#### **B-11. Multiple Comments: *Section 95105(c)(3) Facility Block Diagrams***

**Comment:** ARB should limit the requirement for diagrams to only combustion fuel flow-related elements as it will be very difficult and of limited value to develop diagrams for minor equipment such as valves and pneumatic devices. (PGE1)

**Comment:** This section discusses the submittal of "simplified block flow or piping and instrumentation diagrams." If the language only included "simplified block flow diagram," this request would not be problematic. By adding "piping and instrumentation," however, the request potentially adds a whole new level of complexity. Considering the array of schematics and their relative complexity applicable to cement manufacturing facilities, CCMEC recommends excluding the "piping and instrumentation" language. Alternatively, CCMEC requests that CARB provide guidance to verifiers on what type of diagrams are sufficient, specify the relevant "production processes" in industry-specific guidance, add sector-specific language on the types of diagrams required, provide examples of the diagrams that CARB would



expect to see in such submittals , and confirm that any proprietary aspects of the diagrams, to the extent required , are excluded from any public disclosure. (CCMEC1)

**Comment:** ARB staff has indicated in meetings that these diagrams may be general process flow block diagrams. Further, it is our understanding based on ARB staff comments that specific location of meters will not be required. Documentation of meter location is available on-site at individual facilities. Further, ARB staff has indicated that diagrams available at refineries have satisfied verifier's needs. To improve the availability of information at other facilities without placing an unnecessary burden on the refining sector and other sectors which already provide sufficient information, WSPA recommends the following change to Section 95105(c)(3):

“Reference to facility records including one or more diagrams (such as simplified block flow or piping and instrumentation diagrams) that provide a clear visual representation of the location and relative position of all measurement devices and sampling locations, as applicable, required for calculating covered emissions and covered product data (e.g. temperature, total pressure, HHV). The diagram(s) may include and label fuel sources, emissions sources, and production processes, as applicable.” (WSPA1)

**Response:** Staff has made several changes to the provisions that address the comments. These changes include narrowing the scope of the required information, focusing on measurement and fuel combustion devices, and clarifying that only relative and not specific location information is required. The requirements were expanded somewhat because the information is necessary to better understand the GHG emission sources and to make the overall facility operations and data review more transparent for verifiers and ARB staff. For additional information, also see the response to Comment B-1 in Section V of this document.

#### **B-12. Comment: *Section 95112(e)Geothermal Facility Reporting***

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. (CALPINE1)

**Response:** Staff agrees with the comment and has incorporated the suggested change for clarity.

#### **B-13. Comment: *Sections 95115 and 95122 Emission Calculations for Natural Gas***

SoCalGas understands that the original intent of having the definition for pipeline quality natural gas was to capture the potentially higher carbon dioxide equivalent emissions from natural gas with higher heating values (HHV) exceeding 1,100 Btu/scf. It appears there is no longer the need for this differentiation. The current and proposed amended regulations are inconsistent in their treatment of natural gas with HHV above 1,100 Btu/scf. For example, natural gas local distribution companies (LDCs) reporting under §95122 are allowed to determine pipeline quality natural gas based on an annual weighted average HHV, but stationary fuel combustion sources reporting under §95115 do not have the same allowance.

Except for refineries, SoCalGas believes there may be few if any mandatory reporters that use calculation methodologies other than Tier 1 or Tier 2 for stationary combustion; therefore, we request that ARB staff conduct an analysis to determine the necessity of continuing the use of the term pipeline quality natural gas in its entirety. The analysis should look at whether there is any difference in emissions between reporters using Tier 1, 2, and 3 for stationary fuel combustion. Since ARB allows LDCs to use Tier 1 or Tier 2 for reporting unless greater than three percent of their total emissions are from natural gas with an annual average HHV above 1,100 Btu/scf, any difference in the stationary fuel combustion category is likely to be very insignificant in comparison. (SOCALGAS1)

**Response:** The provided comments are outside of the scope of this rulemaking as staff did not propose any changes to these requirements. However, as stated in ARB guidance,<sup>7</sup> staff agrees that the end users of natural gas received from utility distribution systems and reporting under section 95115 should rely on the annual average HHV, CH<sub>4</sub>, and CO<sub>2</sub> for purposes of determining whether the natural gas meets the definition of “pipeline quality” natural gas.

#### **B-14. Comment: *Section 95118(e) N<sub>2</sub>O Emissions Source Testing***

In the proposed amendments to the MRR, CARB staff have recommended nitric acid production facilities increase performance testing for N<sub>2</sub>O 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 N<sub>2</sub>O emissions from nitric acid plants reporting to the program.

In Simplot's operational experience, variability observed in N<sub>2</sub>O emissions from the nitric acid process are not as a result of changes in manufacturing conditions (e.g. 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

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<sup>7</sup> Petroleum and Natural Gas Systems Emissions Reporting Guidance for California's Mandatory Greenhouse Gas Reporting Regulation, 2/22/2016. <https://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/oil-gas.pdf>

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, N<sub>2</sub>O 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 N<sub>2</sub>O 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 N<sub>2</sub>O 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. (SIMP1)

**Response:** To improve emission estimates, and to better account for potential variability, staff proposed inclusion of an additional source test (a second test), to better capture changes in emissions over the course of the year, to improve accuracy for nitric acid production emissions estimates. Staff agrees that a nitric acid plant without breakdowns of control equipment or other malfunctions will have consistent emissions. If that is the case in the future, staff can consider revising the testing requirement.

#### **B-15. Comment: *Section 95129 CEMS Breakdown and Substitute Data***

This section discusses an unforeseen breakdown of continuous emissions monitoring system equipment used at a combustion and/or process unit(s) using Tier 4 Calculation Methodology to monitor and report emissions. CCMEC requests that CARB clarify the following:

- (1) What is the minimum duration of a breakdown for which it would be acceptable to use an alternate tier?
- (2) Can this be used in lieu of Part 75 or other data substitution methods for extended outages?
- (3) In addition to breakdowns is it possible to retroactively petition to use an alternate tier instead of using Part 75 data substitution or other data

substitution method should an issue be discovered? For example in instances where a facility's CEM was recording data, but the data was not accurate for an extended period of time, would a facility be allowed to calculate emissions with a lower tier methodology retroactively provided the facility was able to produce the required testing and data to calculate emissions? (CCMEC1)

**Response:** Staff did not propose any changes to this section of the Regulation during rulemaking that alter how ARB implements the existing provisions in this section. Therefore, the implementation clarifications requested by CCMEC are out of scope for this rulemaking. Staff publishes guidance to address implementation questions and is happy to assist reporters in working through any questions that arise during data collection and reporting. The proposed changes to section 95129(i)(1) allow facilities with unforeseen CEMS breakdowns to also use Tier 1 calculation methods in addition to the current provision that allows Tier 2 or Tier 3 methods to be used in such cases, and provide an option for cement kiln operators to temporarily calculate process emissions during CEMS breakdowns. These minor changes increase the flexibility for operators that must use interim methods during CEMS breakdowns but do not alter how ARB implements the existing provisions.

**B-16. Comment: *Section 95130(a)(2) Remove Reference to California Climate Action Registry***

Additionally, since the California Climate Action Registry no longer exists, and has been succeeded by The Climate Registry, we suggest that this reference be deleted. (PGE1)

**Response:** Staff did not propose any changes to this section of the Regulation during this rulemaking; therefore, this comment is out of scope for this rulemaking.

**B-17. Multiple Comments: *Sections 95131(c)(4)(B), 95131(c)(5), (f) and (g) – Timing Requirements for Requests from ARB***

**Comment:** The proposed amendments would require reporters to provide a written response, including supporting documents and calculations, within five calendar days of a request from the Executive Officer. This reduction in response time by over 75 percent is unreasonable, particularly since the amendment does not consider non-workdays (weekends and holidays). This will not allow sufficient time to compile, review, and validate a reporter's response. PG&E proposes that ARB allow at least 10 business days for a reporter to respond to a request, and allow the Executive Officer to grant an extension. This provision will provide sufficient time for a response and align with Cap-and-Trade regulatory language, and will allow the reporter additional time for a response upon ARB approval if an extraordinary situation arises. (PGE1)

**Comment:** In general, WSPA recommends that ARB be consistent in its use of deadlines by using working days instead of calendar days. Working days should be defined to exclude, at a minimum, weekends and national and state holidays.

In Section 95131(c)(4)(B) and (c)(5), ARB has revised information request response deadlines from 5 working days to 5 calendar days. It is understood that ARB is attempting to lend clarity as “working days” may not be a term consistently interpreted by reporters and verification bodies. However to be consistent with other “working day” changes proposed (i.e., 10 working days to 14 days), WSPA recommends that ARB must allow at least 10 working days for any activity for which potential exposure to penalties could be involved. To give entities less than that is unreasonable and arbitrary.

In Sections 95131(f) and (g), the proposed language, changes the reporting entity response time and verifier response time to ARB inquiries, from 20 working days to 5 days without any indication of the breadth of ARB inquiries (i.e., inquiries may be simple or very complex). Demanding responses in 5 days without consideration of the level of effort, weekends and holidays, and the availability of key resources makes this substantial reduction of response time untenable. (WSPA1)

**Response:** Based on the comments, staff changed the requirements in both sections 95131(c)(4)(B) and (c)(5) to “ten days” allowing additional time to respond while eliminating the term “working day” and basing the requirements on calendar days. Based on the comments, staff changed the response time for sections 95131(f) and (g) to “14 days” (14 calendar days) to allow additional time, while still shortening the original response time to help ensure on-time verification and timely data review.

#### **B-18. Multiple Comments: *Cal e-GGRT System Improvements***

**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. (CALPINE1)

**Comment:** Software upgrades to Cal-e GGRT system could ease the burden associated with reporting and verification for entities reporting on behalf of multiple subsidiaries and affiliates. This might include allowing for batch review and certification for multiple facilities, removal of the redundant password request for each report certification, data loading from the previous year’s report, elimination of duplicate reporting from the Subparts, and the ability to upload one Excel sheet for gas-insulated switchgear (SF6) reporting for multiple affiliates and subsidiaries. (CCEEB1)

**Response:** These comments are related to the GHG reporting tool functionality and are outside the scope of the regulatory amendments, so no Regulation changes are required. However, staff continues ongoing work with reporters to improve the Cal e-GGRT reporting tool, and we will consider the appropriateness of the suggested updates. Staff has initiated a project to allow batch review and submission of reports within Cal e-GGRT, to help streamline the reporting process for entities submitting multiple reports.

#### **B-19. Comment: *Forest Fire CO<sub>2</sub> Emissions***

I see that AB 32 was passed without considering the impact of forest fires on CO<sub>2</sub> emissions. Why this was ignored I just can't understand. Consider the following data gathered from very reliable sources.

Just looking at the Chimney and Soberanes fires alone this year 30 tons/acre were lost by the missing CO<sub>2</sub> absorption by the living forest. Another 200 tons/acre of CO<sub>2</sub> were produced by the burning and subsequent decay of the burned forest. So far the two fires have consumed 150,000 acres of forest. This conservatively totals 34,000,000 tons of CO<sub>2</sub> production. Just maybe this isn't an insignificant number? If 1/2 of your yearly budget were spent on paying more attention to fire suppression tools and personnel this number could be significantly reduced. Remember, this was just 2 of the fires this year and neither is controlled by this date!!! If you don't believe these numbers please spend a little time to verify them. (CTAM1)

**Response:** The submitted comment is not related to the proposed MRR amendments, but is included here for completeness. Since this comment is out of scope, no response is required.

### **C. Fuel Supplier and Biofuel Reporting Requirements**

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#### **C-1. Comment: *Changing the Point of Regulation to LPG Importers***

AmeriGas supports the ARB's proposed amendments to the MRR<sup>6</sup> in furtherance of maintaining a robust and accurate greenhouse gas reporting program. AmeriGas agrees with the ARB's statement that a modification to the point of regulation for importers of LPG is needed in order to ensure more complete emissions coverage in the reporting program for LPG.<sup>7</sup> There is ambiguity inherent in having the "California consignee," as that term is currently defined in the MRR, as the point of regulation for LPG importers. The proposed new definition of "importer of fuel" provides improved clarity over the existing definition for "consignee." AmeriGas notes the importance of AB 32's statutory requirement to "prevent emissions leakage to the extent feasible"<sup>8</sup> and believes that the proposed amendment is needed in order to address the potential for leakage to arise from LPG distributors reducing their own emissions position below the reporting threshold by disaggregating it among their customers.

<sup>6</sup> Notice at 5.

<sup>7</sup> Staff Report at 20.

<sup>8</sup> AB 32 § 38562(b)(8) instructs ARB to design its MRR and Cap and Trade regulations in a way that minimizes system “leakage,” which is defined as “a reduction in emission of greenhouse gases within the state that is offset by an increase in emission of greenhouse gases outside the state.” § 38505(j).

(AMGAS1)

**Response:** ARB staff appreciates support for the change, and agrees that the originally proposed “importer of fuel” definition did not contain enough specificity to prevent LPG importers from potentially disaggregating their reported volumes amongst customers. Therefore, further revisions to the definition were made based on the information provided by Amerigas. The revisions are intended to specify that ARB considers the importer of fuel to be the entity selling the imported fuel to the California customer regardless of whether the California customer takes title to the fuel inside or outside of California. The intent of this revised definition is to ensure that an importer of fuels should not be able to disaggregate their reporting obligation amongst downstream customers or otherwise employ complicated contractual structures for purposes of avoiding reporting or Cap-and-Trade Program compliance obligations for the emissions associated with the imported fuels.

## **C-2. Comment: *Section 95122 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.

North America's leader in clean transportation 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. (CE1 and CE2)

**Response:** ARB staff appreciates support for the change, and agrees that the original proposed "importer of fuel" definition did not contain enough specificity to prevent LNG importers from potentially disaggregating their reported volumes amongst customers. Therefore, further revisions to the definition were made to address this concern based on the information provided by Clean Energy. The revisions are intended to specify that ARB considers the importer of fuel to be the entity selling the fuel to the California customer regardless of whether the California customer takes title to the fuel inside or outside of California.

### **C-3. Comment: *Definition of "Importer of Fuel"***

In addition to clarifying the importer as the point of regulation, ARB should consider further expansion of the definition for LPG importers of fuel to fully prevent leakage via disaggregation. Even under the proposed definition, an available "paper" strategy for LPG distributors would still exist allowing them to disaggregate emissions positions among their customer bases. By simply shifting the contractual point of delivery and transfer of title to the customer from the customer's California storage tank to a terminal outside of California an opportunistic LPG distributor can disaggregate their emissions position and sidestep being the "importer" and the first entity to take title to the fuel within California. Spread across enough customers (including both LPG end-users and other distributors), such disaggregation can reduce an LPG distributor's emissions position below the thresholds that trigger MRR and Cap and Trade Program compliance. For example, an opportunistic LPG distributor may arrange to have its California customers take title and delivery of the product across the border in Nevada, with full knowledge that the customer will be taking the product into California for combustion. In such a scenario, the LPG distributor might argue that a strict interpretation of the proposed definition of an LPG "importer of fuel" makes the customer the point of regulation, not the distributor. In order to avoid such behavior similar to the scenario described above, ARB could add language to the proposed definition of "importer of fuel," specific to LPG importers, to address this type of behavior. For example, such additional language specific to LPG could read as follows:

If the first entity to hold title to the fuel in California is also the end-user or other distributor of the fuel and is purchasing the fuel outside of California from an importer or distributor that prior to 2015 transferred title to fuel in California upon delivery to such end-users' or other distributors' storage tanks then such importer or distributor shall be



deemed the “importer of fuel” instead of the end-user or other distributor for the purposes of this subarticle.

Beyond the additional language to the proposed definitional amendments set forth above, ARB should consider a corresponding revision to the subarticle of the MRR concerning enforcement.<sup>10</sup> Such revision could add language making it an enforceable violation of the MRR or Cap-and-Trade rule to intentionally avoid regulation by disaggregating LPG-related emissions positions in the manner detailed above.

<sup>10</sup> 17 CCR § 95107 (AMGAS1)

**Response:** ARB staff agrees that the definition should be clarified to prevent potential disaggregation of reportable LPG volumes, and proposes changes to the definition to address this concern as described in the response to comment C-1. Revisions or additions to enforcement provisions of the MRR are not necessary because non-reporting is already considered a violation under MRR, given the modifications described in response to C-1.

#### **C-4. Multiple Comments: *Section 95852.1.1 Eligibility Requirements for Biomass-Derived Fuels.***

**Comment:** 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 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. (CE1)

**Comment:** And then for the purposes of time, we have one other issue with the eligibility requirements for the biomass – biomass-derived fuels. The eligibility requirements under Section 95852.1.1 for biomass derived fuels continue to apply only to biogas and biomethane, among all biofuels. And we think if resource shuffling is to be applied at all under this regulation, it should be applied to all biomass fuels, not just biogas. (CE2)

**Response:** The commenter requests modifications to both MRR and the Cap-and-Trade Regulation. With respect to MRR, which is the subject of this rulemaking, ARB staff disagrees with the commenter and notes that resource shuffling concerns noted in the 2010 rulemaking still apply at this date. 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 MRR, "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 portions of the comment that refer to proposed changes to the Cap-and-Trade Regulation are outside the scope of this rulemaking, and may be addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons for that rulemaking proceeding in parallel with the MRR rulemaking. Notwithstanding this, staff notes that the Cap-and-Trade Program's requirements are designed to avoid a situation in which Program incentives result in no net change in GHG emissions to the atmosphere. One example is the incentive to purchase biomethane, which is treated as an exempt fuel under the Program.

The biomethane provisions in the Cap-and-Trade Regulation are thereby designed to ensure that imported biomethane does not come from sources that were previously being sent 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, and resource shuffling provides no benefit to the atmosphere under California's Program.

The purchaser of imported biomethane that 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-5. Comment: *Section 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. (CE1)

**Response:** ARB staff understands the concerns expressed in the comment, but opt to forego the requested changes. Staff believes the requirement proposed in the comment would be difficult for local distribution companies (LDCs) to meet and for ARB to implement. Under MRR, the burden of evidence is on the claimant of the biomethane directly, and failure to provide such evidence leads to the resulting emissions being reported as non-exempt biomethane or fossil natural gas. Even with the stipulation that the LDC only report the supplied biomethane as exempt in cases where the biomethane supplier provided evidence, LDCs and their verifiers would be required to assess the evidence for any end user who wishes to purchase biomethane, regardless of amount. Furthermore, this approach risks potential non-compliance by any LDCs if potentially-eligible biomethane is not reported.

Staff's proposal to allow the voluntary reporting of biomethane by LDCs for this purpose allows for end users of the fuel to purchase and use biomass-derived fuels, while providing flexibility to LDCs. End users of natural gas who are covered entities may report the eligible biomethane directly in their emissions data reports. End users who are not covered entities (such as most consumers of CNG as transportation fuel) still have the opportunity to work with their LDCs to provide evidence of their purchase of eligible biomethane, for the LDC to report.

#### **C-6. Comment: *Reporting End User Data for LNG***

It is WSPA's understanding from discussions with ARB staff that the end-user data reporting requirements under Section 95122(d)(7) and (8) apply only to liquefied natural gas (LNG) only transported in interstate pipelines. ARB's written confirmation of this understanding is requested. (WSPA1)

**Response:** WSPA's understanding is correct regarding the new requirements in Section 95122(d)(7); only facilities that make liquefied natural gas (LNG) are required to report the customer delivery information specified in 95122(d)(7). Regarding section 95122(d)(8), both LNG suppliers and natural gas liquid (NGL) fractionators are required to report the volumes of fuel that are excluded from emissions reporting due to delivery to a destination outside of California. This requirement applies only to fuels that are otherwise reportable by the LNG supplier or NGL fractionator, but are excluded from the emissions calculation due to documented delivery to a destination outside of California.

**C-7. Comment: *Section 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. (CE1)

**Response:** This comment deals with provisions under the Cap-and-Trade Regulation, and is therefore out of scope for this MRR rulemaking.

**C-8. Comment: *95113(m) Designated Volume of Oxygenate***

Section 95113(m)(1) indicates that the operator must report the quantity of CARBOB produced and imported for use in California “and the designated volume of oxygenate associated with the reported CARBOB”. The term “designated volume of oxygenate” is not defined in the regulation. One interpretation is that this is the amount of oxygenate that the producer of the CARBOB specifies in the predictive model notice with each production of CARBOB – although what is provided in the predictive model notice is expressed as a percentage and not a “volume” as suggested in this reporting requirement. It is not clear that this is CARB’s interpretation. Ultimately, the CARBOB producer may not be the person blending the oxygenate in the distribution system and so cannot know the exact amount of oxygenate added to the final blend – only what was designated when the CARBOB was first produced or imported. WSPA requests that ARB define what “designated” means and relate it to the predictive model notice and the percentage designated on that notice. (WSPA1)

**Response:** This comment is out of scope for this rulemaking because changes to this section were solely for readability and did not amount to substantive changes to the reporting requirements of this section. ARB staff has provided guidance on this topic in the AB 32 Cost of Implementation Reporting and Verification Frequently Asked Questions (FAQs) guidance document available on the Mandatory Reporting guidance webpage at:  
<https://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/guidance.htm>.

**C-9. Comment: 95113(m) Volume of Biodiesel and/or Renewable Diesel Associated with the Reported Fuels**

Section 95113(m)(3) requires that the operator report the quantity of California Diesel produced and imported for use in California “and the volume of biodiesel and/or renewable diesel associated with the reported fuels”. Unlike CARBOB, where the oxygenate blend percentage is designated on the predictive model notice, no such notice related to biodiesel or renewable diesel is required by ARB. The California Division of Measurement Standards under the California Department of Food and Agriculture does require product transfer documentation and dispenser labeling consistent with federal trade commission standards for biodiesel blends or renewable diesel blends above 5% - but there is no such designation for blends below 5%; and even the blends above can be designated as a range (i.e., 6%-20%).

Because there is no designated specification, there is no way to know what downstream parties might blend into the diesel fuel in terms of biodiesel and renewable diesel. We understand that it is ARB’s intent to only require reporting of the quantity of biodiesel and/or renewable diesel that the producer or importer added to the fuel which is known and not some speculative volume that other parties might have added subsequent to the initial production or import. WSPA recommends that the current language be modified as follows:

“California Diesel produced and imported, as defined by “California diesel” in section 95202 of the AB32 Cost of Implementation Fee Regulation, for use in California and the volume of biodiesel and/or renewable diesel associated with the reported fuels added by the company that produced and/or imported this California Diesel”. (WSPA1)

**Response:** This comment is out of scope for this rulemaking because changes to this section were solely for readability and did not amount to substantive changes to the reporting requirements of this section. ARB staff has provided guidance on this topic in the AB 32 Cost of Implementation Reporting and Verification Frequently Asked Questions (FAQs) guidance document available on the Mandatory Reporting guidance webpage at <https://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/guidance.htm>.

**C-10. Comment: 95150(a) Onshore Natural Gas Processing Categorization**

Section 95150(a)(3) changes the definition for onshore natural gas processing by replacing existing language as follows:

“This industry segment includes processing plants that have an annual average throughput of 25 MMscf per day or greater, and fractionation facilities that have no petroleum and gas production activity within the same basin.”

Pursuant to discussions with ARB staff, WSPA suggests the following language modification for clarity regarding intended applicability of this section:

“This industry segment includes processing plants that have an annual average throughput of 25 MMscf per day or greater. This industry segment also includes fractionation facilities that have no petroleum and gas production activity within the same basin.”

Further clarity can be provided by adding to the end of Section 95150(a)(2):

“Onshore natural gas processing equipment as defined in section 95150(a)(3) that is owned and/or operated by the facility owner/operator and located within the same basin is considered “associated with a well pad” and is included with the onshore petroleum and natural gas production facility, unless such equipment is required to be reported as part of a separate onshore petroleum and natural gas processing facility. Processing plants that have an annual average throughput of 25 MMscf per day or greater are not subject to this section.” (WSPA1)

**Response:** Staff agrees and made clarifications based on these comments in a subsequent 15-day package.

## **D. Product Data Reporting**

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### **D-1. Comment: *Section 95102(b)(38) Dairy Product Data Definitions***

Saputo supports ARB’s objective to clarify covered product data definitions and to align those definitions with the actual products produced by industrial entities participating in Cap-and-Trade Program. Saputo agrees with ARB that streamlining product data reporting and product-based benchmarks for the fluid milk and related product manufacturing sectors is an important policy objective. Saputo understands that ARB is reviewing benchmarks for certain milk-based products and may propose revised definitions as part of a subsequent 15-day comment period. Saputo respectfully requests that ARB consider revising the definition for “deproteinized whey” and include it in the subsequent 15-day comment period.

Operation of the current definition of deproteinized whey (“DPW”) results in disparate treatment of Sweet Dry Whey (“SDW”) under the MRR and, in turn, the Cap- and-Trade Program. Saputo believes the current definition of DPW is too narrow and should be broadened to allow SDW to qualify as DPW. The MRR’s current definition of DPW requires the powder produced to contain greater than 80% carbohydrate (lactose) levels. As SDW contains approximately 69% carbohydrate (lactose) levels, it technically does not qualify as DPW. This minimum carbohydrate requirement results in Saputo’s production of SDW to be ineligible for the industrial assistance that otherwise would be provided by ARB.

Saputo was unable to locate any rationale or other support in the rulemaking record for the inclusion of this minimum carbohydrate requirement in the definition of DPW.

Indeed, we believe the minimum carbohydrate requirement creates an arbitrary and unnecessary distinction between DPW and SDW, two very similar products that utilize the same amount of energy in processing. The process used to produce DPW is very similar to the process for SDW. We utilize the same source whey solids as a by-product from cheese manufacturing and a by-product from milk ultrafiltration. From these sources of whey solids and based on prevailing markets, we flex production to produce all whey products at highest return possible. DPW and SDW utilize the same process and equipment to remove water to the point of producing free flowing powder at the same solids level.

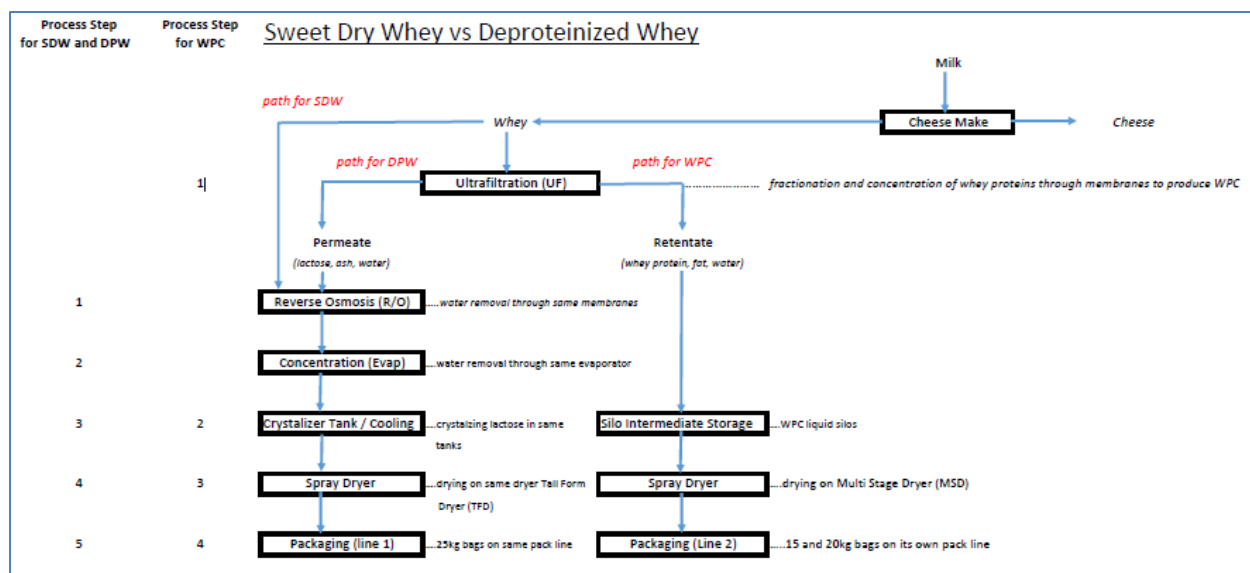
The process of making DPW or SDW is nearly identical. Membranes are used in both products. In both cases, whey is introduced to the membrane process just prior to concentration through an evaporator where water is further removed to approximately 55% solids. This is done through the same process on the same evaporator. Both products are stored and cooled through controlled cooling curves in the same storage vessels. From this point, product is introduced to the same powder drier where product is dried from 65% moisture levels to 5% moisture levels to a non-hygroscopic, free flowing powder and packaged on the same packaging equipment. Finished powders have the same moisture levels. It is our belief that these two products should be considered interchangeable by ARB due to being produced from the same available whey solids through the same equipment. Although SDW is not the exactly the same as DPW from a standard of identity perspective (i.e., due to carbohydrate content), it is the same from an energy use and greenhouse gas emissions standpoint. Attached is a diagram depicting the processes for the production of DPW and SDW.

For the foregoing reasons, we request that ARB consider revising the definition of “deproteinized whey” currently located at MRR §95102(b)(38) as follows:

“Deproteinized whey” means products manufactured through the membrane filtration cold ultrafiltration of sweet dairy whey, removing a portion of the protein from sweet whey to result in a non-hygroscopic, free-flowing and clean flavored powder containing greater than 80% carbohydrate (lactose) levels.

Saputo believes revising the definition of DPW in this fashion would advance ARB’s objectives in the MRR and Cap-and-Trade Program rulemakings by, among other things, improving the accuracy and comprehensiveness of the covered product data definitions.





(SAPUTO1)

**Response:** Staff acknowledges Saputo's concern that the existing MRR and Cap-and-Trade Regulation definitions for "deproteinized whey" do not accurately describe their product. In order for any proposed change to be considered, it has to be identified as part of the 45-day regulatory change proposal. Since the issue regarding the definition of deproteinized whey was not brought to ARB's attention until after the release of the 45-day regulatory change proposal, staff cannot make the requested change in this rulemaking. Staff will continue to work with Saputo on this definition, and will seek to include the updates in the next revisions to MRR and the Cap-and-Trade Regulation.

## D-2. Comment: *Nitric Acid and Calcium Ammonium Nitrate Solution Product Requirements*

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 sell in advance of a public comment period. (SIMP1)

**Response:** ARB looks forward to collaborating with stakeholders on this topic.

#### **D-3. Comment: *Reporting of Thermal Energy***

Section 95112(b)(3) has been modified to now require reporting of thermal energy that is vented, radiated or discharged. WSPA is opposed to this change in the regulation as it is duplicative and, therefore, unnecessary. Thermal losses can be determined by the reported combustion fuel inputs to Electricity Generating Units. (WSPA1)

**Response:** The inclusion of vented, radiated, wasted, or otherwise discharged thermal energy as part of total thermal output reported to ARB clarifies the existing requirement to report all thermal energy for electricity generating systems that is not used, sold, or in support of power generation. No additional reporting requirements are being proposed, nor is it possible to calculate thermal efficiencies from the fuel usage reported by electricity generation unit operators. Energy flow data reporting is needed to maintain the state-wide inventory mandated by AB 32, and for Cap-and-Trade Program benchmark development, energy efficiency evaluation, carbon cost distribution analysis, and informing future energy policies (page 58 of the 2012 MRR FSOR<sup>8</sup>). Because this data is not covered emissions or covered product data, including steam, reporting entities may use a reasonable estimate to continue reporting total thermal output for cogeneration and bigeneration electricity generation systems.

#### **D-4. Comment: *Reporting of Refinery Product Data***

Sections 95113(l)(1) and (3) have been modified to eliminate redundant product reporting for refineries and new reporting requirements have been proposed. WSPA is opposed to the addition of the new reporting requirements. These data are unnecessary from a Cap & Trade standpoint. If ARB needs data for unrelated purposes, they can obtain sector level data from other agencies or request it by survey. ARB should eliminate requirements to report data that are subject to verification and potential enforcement exposure and penalty of reduced allowances that is not required for cap and trade. It is wholly unreasonable to subvert the Mandatory Reporting Regulations from a Cap & Trade purpose to any ARB regulatory need which then imposes severe burdens and deadlines on covered entities. (WSPA1)

**Response:** ARB appreciates the support for streamlining reporting requirements under section 95113(l). The collection of refinery products data is not a new requirement. The changes to the requirements for refinery products reporting represent a consolidation and clarification of prior reporting requirements to reduce the time and effort required of facility operators. The product information reported under the amended Regulation pursuant to new section 95113(l)(1) is the same information that refineries currently report monthly to the U.S. Energy Information Agency (EIA) via Form EIA-810. Because the amended Regulation requires reporting of the same information that is already reported to EIA, using

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<sup>8</sup> <https://www.arb.ca.gov/regact/2012/ghg2012/ghg2012finalfsor.pdf>

identical reporting methods, staff believes that the new reporting requirements are clearer and will be easier to comply with than the previous requirements.

Although MRR continues to collect data that support multiple ARB programs, including the Cost of Implementation Fee Regulation, the product data that are referenced in the comment are needed by the Cap-and-Trade Program. In the absence of this refinery product reporting, the only information available to the Cap-and-Trade Program about refinery production would be the complexity-weighted barrel (CWB) information. While staff finds CWB to be a useful measure of refinery activity for allowance allocation, it does not necessarily correlate to on-site production of real products, such as gasoline and diesel fuel. Staff needs information about real products to understand the actual level of on-site production at refineries and to assess that a primary purpose of industrial allowance allocation—preventing emissions leakage—is being served for this sector.

Under the proposed amendments, these product data (e.g., quantities of refinery products such as CARBOB, jet fuel, petroleum coke) are not covered product data. As such, they are subject to verification for conformance only, and are not subject to material misstatement evaluation. Furthermore, because the requirements proposed are aligned with current EIA reporting, and, because the reported data are not subject to material misstatement review, ARB believes that any additional reporting and verification burden will be minimal.

#### **D-5. Comment: *Reporting of Aviation and Marine Fuels***

In Section 95121(d)(9), ARB is proposing to require the reporting of fuels previously excluded from emissions reporting due to demonstration of a final destination outside of California, used exclusively in aviation and marine applications, or that was previously delivered. ARB has indicated that this data is being requested by the LCFS staff within ARB. It is inappropriate for MRR entities to be burdened with non-MRR information requests within this regulatory construct. If there is a rationale for additional LCFS-related information requests, then this should be vetted with LCFS stakeholders in that regulatory proceeding. WSPA believes that there is no need for such data to be reported and this is the wrong way to collect such information. We strongly object to ARB collecting highly confidential business data without having a strong link to a regulatory purpose. (WSPA1)

**Response:** Staff is proposing to add section 95121(b)(9) to facilitate verification of emissions associated with fuel volumes reported under MRR. This reported data is not being requested by LCFS staff, as indicated by the reporter. Emissions from fuel that is used for marine or aviation purposes or has a destination outside of California do not need to be reported under MRR; however, the excluded volumes must still be reviewed for accuracy by the verifier and substantiated as being appropriate for exclusion to ensure that the correct amount of emissions are being reported in the MRR emissions data

report. Because this data must already be collected and provided to the verifier upon request, there is no additional burden for reporting entities to enter that data into the emissions data report. ARB staff believes these provisions are necessary to support overall data quality for MRR and to facilitate the verification of excluded fuels. Please note that this new provision does not require transportation fuel suppliers to report the volume of any fuels that are not included in Table 2 (e.g. aviation gasoline, jet fuel etc.).

#### **D-6. Comment: *Eliminating Certain Data Reporting Requirements***

Other reporting requirements which WSPA believes are unnecessary and requests that ARB consider eliminating include:

- Atomic Hydrogen Reporting Requirements (95114(e))
- Hydrogen Purchase and Sale
- By-product Hydrogen (95114(l))
- Natural gas purchases, electricity, and thermal energy reporting (e.g., in 95115(k), 95103(a)(1), 95104(d), 95112(a), and 95112(b)) where it does not factor into Cap and Trade obligations (WSPA1)

**Response:** At the request of hydrogen plant operators, ARB established and then revised the benchmark for on-purpose hydrogen, and published guidance on how on-purpose hydrogen is to be reported to ARB. The reporting requirements related to atomic hydrogen support the statewide GHG emissions inventory program; it provides staff with real data to distinguish between process emissions and combustion emissions for hydrogen production. Reporting by-product hydrogen supports staff's evaluation of overall hydrogen production at refineries. These data are needed for staff to evaluate the contribution of steam methane reformers to the total production of hydrogen at refineries. It is important for staff to align currently reported hydrogen production data with the data upon which the on-purpose hydrogen production benchmark is based, and by-product hydrogen data play a role in that analysis. Staff does not view by-product hydrogen reporting as an indefinite requirement and will revisit the need for this reporting requirement in the next MRR rulemaking process.

Other data elements, including natural gas purchases and steam purchases/sales, allow ARB to compare these energy exchanges between two different regulated parties to ensure the correct quantities of natural gas, electricity, and steam are consistently being reported by both data reporters. Natural gas purchase data is used by ARB to calculate compliance obligations for natural gas suppliers under the Cap-and-Trade Program.

#### **D-7. Comment: *Section 95114 Hydrogen Product Sales Reporting***

Air Products strongly supports the narrowing of the data reporting requirements for hydrogen product sales. We agree that the data collected will help in meeting other

ARB objectives, such as determinations under the Low Carbon Fuel Standard. The proposed revisions to §95114(j) suggest the level of data granularity for hydrogen product sold to hydrogen fuel stations is at the “facility” level. While this makes sense for product sold to refineries, we do not agree this level of reporting granularity is needed for hydrogen sold to fueling stations. Further, product may be sold to a third-party entity that is filing multiple individual stations, obscuring the specific sales to an individual facility. Air Products requests that the hydrogen products sales to hydrogen fueling stations can be reported as a total aggregated value, or at the least, as the total to the purchasing entity, without breaking such sales data down to the individual fueling stations, themselves. (AP1)

**Response:** Staff believes that the revision, as written, allows reporters to comply by reporting the sales of hydrogen to vehicle fueling stations as the quantity sold to the purchasing entity (“the purchaser or receiver”), as described in the comment. In other words, the requirements are consistent with what is requested by the comment, in that sales to individual fueling stations is not required or expected. This approach is consistent with the previous reporting requirement, and staff will ensure that the intent is clear in our guidance documents.

## **E. Verification Requirements**

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### **E-1. Multiple Comments. *Verification Deadline Change***

**Comment:** I am a GHG verifier with CARB. If the verification submittal data were changed from September 1 to August 1 this year, I would have had at least 5 reporters with an adverse or qualified verification statement. Often times it take a reporter, even a seasoned report, time to accurately report its GHG emissions or product data. The reason provided by CARB for this change is flawed at best. There seems to be no analysis provided for the impacts on the reporter (who ultimately support the MRR program) and the VB who assist CARB in the efforts to reduce GHG emissions throughout CA. Please provide a discussion of the impacts to the reporters and VB. Implementation of this change in Regulation without this analysis could be a violation of CEQA. To change the verification submittal date based solely on CARB's inability to do its job is unreasonable. Verifier's and reporters have put in long hours to conform to the requirement of the MRR and I would expect CARB to understand and respect their commitment. (AES1)

**Comment:** LRQA is concerned with the proposed change in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions which would move the verification deadline from September 1st to August 1st. Much of the scheduling for our business outside of ARB work has been structured around the ARB September 1st deadline. A change to August 1st would have a significant impact on the number of verification projects (both ARB and other voluntary and mandatory programs) that LRQA would be able to perform in a given year with adverse effects on our bottom line.

Your analysis results stating verification bodies can more effectively use their time leading up to the verification deadline is likely not taking into consideration work verification bodies perform under programs not related to California initiatives. For instance, LRQA's team of verifiers are booked on verifications under a number of voluntary programs from early spring through the entire month of June. If ARB's analysis has not taken into consideration non-California related verification activities, the analysis has not adequately address LRQA's business situation and that of many of the other ARB accredited verification bodies. With the balance of schedules for various programs we work in, your suggestion that a more effective use of time with a shift to starting the verification cycle earlier would not alleviate the adverse effects on our business.

Taking into consideration the adverse effect this will have on the business of many of the ARB accredited verification bodies, if there is an adequate internal need for ARB schedule adjustments, we strongly encourage you to consider either a one or two week change rather than an entire month. (LRQA1)

**Comment:** Sections 95103(f) and 95103(h)(1) – Verification Requirement and Deadlines. PG&E appreciates the need to provide ARB staff sufficient time to complete all mandated tasks under the Cap-and-Trade Program. However 13 of the 15 MRR reports that PG&E generates from multiple business groups (including gas compression, storage and supply, electricity generation and electricity imports) are verified annually. These verifications can include site visits to facilities located throughout the state. After eight years of experience, PG&E has found that verification activities for a complex and diverse system consistently take longer than anticipated, even after meticulous planning. Delays can occur because of:

- The additional time required by verifiers to perform quality assurance checks and analysis prior to issuing an opinion.
- The verifiers' need to consult with ARB staff to obtain regulatory clarity on specific MRR language.
- The time required by PG&E to iteratively respond to requests from the verifier.
- Competing commitments of verifiers with other reporters.

The rigor of the verification process will make it a significant challenge for PG&E to meet the proposed August 1 verification deadline annually, and will increase PG&E's risk of untimely reporting, consequential enforcement actions, and loss of Cap-and-Trade allowance allocation. PG&E recommends that the current deadline be maintained; however, if the deadline must be advanced, PG&E recommends it be advanced to August 15, which would allow ARB staff over two additional weeks to perform their required tasks than under the current regulation. While PG&E respects the time necessary for ARB staff to perform its tasks, leaving enough time for reporting entities to submit accurate, verified data for ARB's review is critical. (PGE1)

**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. (CALPINE1)

**Comment:** 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. (MWDSC1)

**Comment:** First Environment offers the following comments regarding proposed revisions to the Mandatory Reporting Regulation. Consistent with our previous comments on this issue, First Environment does not support revision of the verification deadline from September 1 to August 1 without further revisions to the regulation to facilitate meeting this earlier deadline. Changing the deadline without making appropriate changes to the MRR to facilitate meeting the deadline will potentially result in a less impartial and/or rigorous verification process, less accurate GHG reports submitted to ARB, and a higher risk of missing the verification deadline for reporters which could result in enforcement action. (FE1)

**Comment:** Staff has proposed changing the verification deadline in section 95103(f) from September 1 to August 1. In our experience, verifiers have needed right up to the September 1 deadline to finish their work. If the verification timeframe is to be moved up, CARB needs to work with the verifiers to ensure that they will be able to meet this new deadline, and that any delay by verifiers will not impact ability of reporting entities to comply with program requirements. (WPTF1)

**Comment:** Moving the Mandatory Reporting Regulation (MRR) report deadline to August 1st will significantly burden both reporting entities and verifiers. While we understand that the CARB is interested in moving the date in order to provide more time for internal quality assurance checks, calculation, analysis, and the data notifications and postings needed to complete mandated activities under the cap-and-trade program, this shift will significantly negatively impact the regulated entities which have set up practices around the September 1st deadline.

Regulated entities in the state have incorporated the September 1st into their business practices to ensure that they are complying with the regulations as set forth by the CARB. Therefore, we recommend that you maintain the verification deadline of September 1st. (CALCHAMBER1)

**Comment:** Verification Deadline/Declining Pool of Verifiers

While we understand ARB's rationale in terms of supporting the Cap-and-Trade allocation process, acceleration of the deadline poses several issues for compliance covered entities and their verifiers. There may be substantial unintended consequences from accelerating the deadline under these circumstances ranging from impacts to data quality to increasing the risk of unintentional noncompliance due to lack of qualified verifiers. To explore the issues and root causes and enhance the stakeholder process, CCEEB would like work with the ARB to host a technical workshop to work through the impacts the verification deadline change could bring, and other issues this proposal brings forth.

Before considering changes to the verification deadline, CCEEB would like to discuss, in a dedicated technical workshop, additional ways to streamline the verification process. For example, we think staff should consider upgrades to software, timing of reporting tool availability, extending the 6-year limit for verifiers, ARB and verifier issue arbitration the release of guidance documents during the verification process, and how certain decisions impact the MRR process.

Additionally, covered entities have EPA reporting deadlines and even earlier than the April 10th deadline that require resources to meet. These reporting deadlines coupled with the earlier verification deadline compresses the schedule too much for all the intermediate steps to occur without complication. With regard to EPA, unfortunately the reports are not similar enough to benefit from concurrent data collection. CCEEB believes all parties would benefit greatly from a technical working group to discuss this proposal from all angles. (CCEEB1)

**Comment:** The California Air Resources Board (ARB) staff proposes to change the verification deadline from September 1 each year, to August 1, to support implementation of the cap-and-trade program. The Initial Statement of Reasons (ISOR) states that obtaining verification statements by September 1 does not provide ARB staff sufficient time to reasonably perform quality assurance checks, calculations, analysis, and the data notifications and postings needed to complete all mandated activities under the cap-and-trade program.

While the change in verification deadline is intended to enable ARB staff to meet their November 1 Cap-and- Trade Regulation compliance deadline, it will adversely impact reporting entities and verifiers who already have difficulties meeting the September 1 deadline, likely resulting in an increase in adverse opinions and more work for all parties. Each year ARB incorporates updates/revisions to the emissions estimating and/or reporting process that require additional days of the reporting entities' staff time in order to complete the modification or addition of responsibilities. This, in turn, results in third party verifiers using additional days to complete their required duties.

Additionally, since ARB staff is tasked by the Cap-and-Trade Regulation to complete assignments by a specified date, instead of reducing the length of time provided to the reporting entities and third-party verifiers to comply with the Reporting Regulation, we



see it as ARB's responsibility to acquire additional staff or to reconfigure staff assignments through time management revisions in order to complete their assignments and ensure compliance.

In summary, CASA recommends that ARB maintain the September 1 verification deadline and augment their staff in order to reasonably perform and complete all mandated activities under the cap-and-trade program. (CASA1)

**Comment:** SMUD opposes the change in the verification deadline from September 1st to August 1st. While the proposed deadline would allow CARB additional time to review the reported data and provide accurate allocations for Cap and Trade purposes, SMUD remains concerned that reducing the time allowed for verification could adversely impact the quality of the verification process.

In SMUD's experience, the proposed reduction in the period for reporting presents significant challenges. In particular, entities that report imported power transactions would face added hardships because they rely on third-parties to provide e-Tag data. Reporting power-transaction data requires entities to gather and provide information from and for several sources, including Open Access Technology International Inc. (OATI), Western Renewable Energy Generation Information System (WREGIS), the California ISO, and other entities that import or export power. The shortened, two-month time between reporting unverified and verified data does not provide enough time to complete the required verification activities for imported emissions without significantly compromising the integrity of the process. (SMUD1)

**Comment:** Air Products feels completion of the verification of the emissions data report by August 1st each year will be challenging for both covered entities and the verification firms. Already we are often challenged in meeting the existing September 1st deadline, even with a verifier who has performed verification for our facility in previous years and is familiar with our operations and reporting approaches. Air Products recommends retaining the September 1st verification deadline and looking for ways to streamline the subsequent ARB review, based on some priority process (e.g. similar to criteria used for tax audits). (AP1)

**Comment:** ARB staff has proposed moving the deadline for completing verification of the annual Greenhouse Gas (GHG) Emissions reports forward an entire month from September 1 to August 1. The rationale for this proposed change is to allow ARB staff more time to perform quality assurance checks, calculations, analysis, data notifications and postings, 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. This additional time will provide covered entities 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 <sup>1</sup>.

While an August 1 deadline may be achievable for verifying the less complicated facility reports, it would be very difficult to achieve for the more complicated entity level reports. The Electric Power Entity reports are already very complex, and ARB's recently proposed amendments and RPS Adjustment guidance will make these reports even more time intensive to verify.

The amount of time allotted for verification of the annual GHG emission reports should be no less than three (3) months. The verification process includes site visits, data checks, resolving questions and making corrections to the report if needed. Some of the verification questions really dig into the details. For example, demonstrating that 1.0 is the appropriate transmission loss factor for electricity imported from a specified generating facility may require review of multiple transmission services agreements. Another example is the new RPS Adjustment guidance that requires the reporting entity to demonstrate that "null power" from out-of-state renewable generating facilities was not directly delivered into California before the reporting entity can claim the RPS Adjustment credit to offset reported GHG emissions for firmed/shaped renewable electricity that is imported into California. It is not feasible to verify data to this level of detail in less than three (3) months. Rather than a one-size-fits-all deadline of August 1 for all GHG emission reports, LADWP recommends a bifurcated approach with two different verification deadlines: 1) August 1 for facility level reports that have a reporting deadline of April 10, and 2) September 1 for entity level reports that have a reporting deadline of June 1. There should be an option for facility level reports to apply to ARB for an extension of the verification deadline to September 1 if needed. This compromise seeks to strike a balance between ARB's desire to have finalized data sooner for determining the Cap & Trade compliance obligation, and conducting thorough verification of the reports to ensure good quality data.

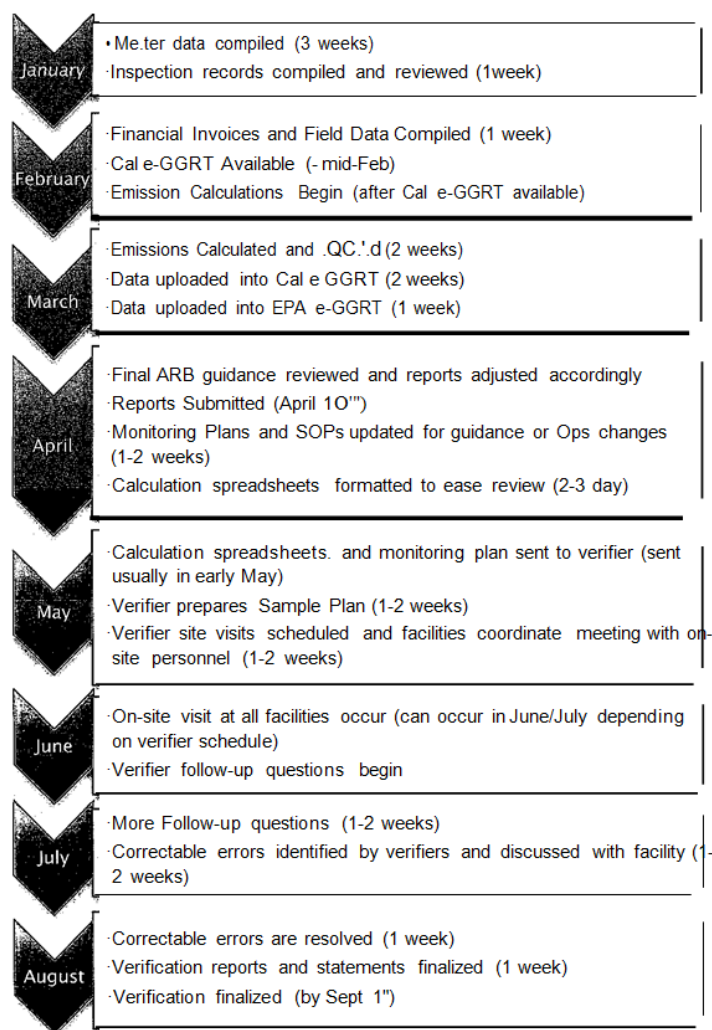
<sup>1</sup> From Page 5 of the Initial Statement of Reasons for the proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.  
(LADWP1)

**Comment:** WSPA is strongly opposed to changing the MRR report verification deadline to August 1st. Moving the verification deadline from September 1st to August 1st in Section 95103(f) will create a significant burden for both reporting entities and verification bodies alike. The verification deadline change to August 1st will likely result in less review of GHG reports and will ultimately, adversely affect verification bodies as they rush to complete their reviews. WSPA has provided substantial information to ARB staff that every month and nearly every week between January and the September deadline is spent organizing, scheduling, presenting, and working through the inevitable iterative process with both verifiers and ARB. This iterative and robust process is critical to a successful verification for complex facilities such as refineries and oil and gas production. The MRR reporting timeline presented in Enclosure A to this letter, which was previously provided to ARB staff, demonstrates the extremely tight reporting timeline that already exists today with the September 1st MRR report submittal deadline.

While strongly in opposition to moving up the verification deadline to August 1st, WSPA believes a far more reasonable option is to, if necessary, consider pushing back Cap &

Trade-related deadlines (i.e., allowance allocation date of November 1st) that appear to have flexibility. Alternatively, if ARB feels strongly about moving forward the September 1st deadline, WSPA requests that ARB consider a compromise verification completion date of August 15th, and eliminate the requirement in Section 95242(c)(4) that the verifier notice ARB in advance of any deficiencies, in recognition of the added scheduling burden to reporting entities. (WSPA1)

**Comment:** Reporting and verification timeline from WSPA (graphic)



(WSPA2)

**Comment:** As we conveyed in workshops and in one-on-one meetings, CCPC is concerned with the regulatory revisions that will make changes to the verification deadline. Specifically, we are strongly opposed to changing the Mandatory Reporting Regulation (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.

We recommend leaving the verification deadline at September 1st and, if necessary, consider pushing back cap-and-trade deadlines that appear to have flexibility.

Alternatively if ARB feels strongly about moving forward with the August 1st deadline, we would request:

- ARB consider 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.

(CCPC1)

**Comment:** We represent business and taxpayer organization. And mainly, we just really wanted to comment basically back to slide 12, upon review of the MRR, we are opposed to changing the verification deadline to August 1st. We believe that moving that deadline is going to create a significant burden for both reporting entities and verification bodies. So we recommend leaving it at the current deadline. And if we need to, maybe push back the cap-and-trade deadlines, because they appear to be more flexible. We did submit our written comments today as well. And we stated there that if ARB does move the deadline, we have some suggestions in those written comments that you might want to consider, for example, providing incentives for advanced reporting and verification, and then maybe even recognition of good faith efforts by obligated parties to provide timely compliance that is otherwise compromised because of the deadline change. Our other suggestions are -- we have about 4 or 5 other ones for your consideration, and I think other people will probably cover that. So thank you for your time. (CCPC2)

**Comment:** The complex EPE reports are due on June 1; due to the increased verifier requirements and scrutiny of these reports, verifiers are requiring more time to complete the necessary work. M-S-R's members strive to complete their reports and commence the verification process as soon as possible. However, preparing comprehensive and accurate reports requires the compilation of data that is not dependent solely on information within the exclusive control of the EPE. Any delays in obtaining and verifying data from third parties delays the EPE's process for reviewing the relevant data and ensuring that the final submission is accurate. Hastening this process is more likely to lead to inadvertent errors and inaccuracies in the final submissions. Added to this are the strict verification processes; data review and site visits are time intensive activities that require coordination between the reporter and the verifier. Even with the current September 1 deadline, M-S-R members have found it challenging to timely comply. The

Staff Report highlights CARB staff's concerns without acknowledging or justifying the added burden that this places on compliance entities and verifiers. Nor is there a demonstration that it is practical or feasible to meet the new deadline. M-S-R is very concerned that accelerating the verification timeline will lead to greater errors or issuance of the qualified verifications, resulting in an overall less efficient verification process.

As a potential alternative, CARB could consider adjusting the verification deadline for facility operators and suppliers that are required to submit their emissions data reports by April 10 of each year. The verification process for those entities could be initiated earlier and would be more conducive to meeting an August 1 deadline. Electric power entities submitting reports on June 1 would still be required to complete their verifications by September 1. (MSR1)

**Comment:** And just briefly on the MRR amendments, we echo concerns with regard to the changed verification deadline. We've been working through the timelines, and our folks find it very difficult to envision being able to timely meet the accelerated verification deadline. And that's not just because of information that they're compiling, but the need to work with other entities to receive information, and then the ongoing work with the verifier site visits and the like. That process just takes too long, and they're very concerned with being able to accelerate the entire process by one month. (MSR-NCPA1)

**Comment:** As indicated in the staff presentation, a proposed revision to the MRR is a change to the verification deadline from September 1st to August 1st. This shortens the verification period by 20 percent for facilities, and 33 percent for electric power entities. And I just bring this up because it is a material reduction in that verification period. It's been our experience that it's not uncommon for verification activities to extend into August and, in some cases, right up to the current September 1st deadline. And staff -- ARB staff presentations have supported this trend towards the end. And in some cases, and in many cases, these delays are outside of the control of verification bodies. If the deadline is changed to an August 1st deadline, as is currently proposed, we are concerned that it will result in reduced quality of reported data, an increased risk in reporters missing the deadline and potential enforcement actions. And we feel that this would be an unfortunate situation at a critical point in the AB -- AB 32 program. ARB staff have presented a need for the change in this deadline, and we respect that argument for the need for the change, and -- but if the August 1st deadline revision is necessary, we request additional revisions to the regulation to facilitate success at meeting the shortened deadline. (FE2)

**Comment:** So, for one thing, advancing the verification due date by one month to August 1st will increase the risk of noncompliance as you've just heard. Fifteen MRR reports are required annually, and that covers hundreds, if not thousands, of facilities, spanning from the Oregon border to Arizona. Seven years of experience has shown us just how meticulous and rigorous these checks are. It just takes time. And August 1st will be a very challenging deadline to meet. We understand that staff are squeezed too,

but we respectfully ask that you direct staff to reconsider this change and continue talking with us to find a workable date or otherwise workable solution. (PGE2)

**Comment:** I'd just like to support Ms. Sullivan's comments in regards to pushing the verification date up to a month. That is a big concern of ours. We have spent many times with Rajinder, and Brienne, and staff in going through our concerns with this proposed change. And, in fact, what we have done also is we did go through a very detailed description of the process that we go through and other members of our industry go through long, intensive process. And I think the bottom line is, and I've said this before, on other revisions of the MRR regulation, is that we all -- we both want accurate information. And even here we are today as we go forward with other reports, it still takes time. It's still a process, especially for those facilities that are larger facilities. So we would request that staff consider the other options that Ms. Sullivan referenced, one of which was pushing the date back. It would allow, you know, both time for staff to do what they need to do, which we realize is very important, but also it preserves our ability for the regulated community to provide an accurate and -- a report so that it is accurate and it supports the Cap-and-Trade Program. One other option too that we would like to throw out for consideration is -- among the options, is that again recognizing what staff's needs are to ensure the -- they have the time to review and do the calculation for the allocations of the program -- for the Cap-and-Trade Program, one other option we had thrown out was what if we were to look at splitting the time? What if we were to settle on a date of August 15th as one option. That way we would be able to at least address our concerns. We would still be constrained. We'd still have to meet the requirements obviously on a reduced time frame, but it also gives staff some additional time as well. So we would respectfully request that, you know, Madam Chair, that you and the Board would consider that as an alternative option, and as a compromise so that we can both get the work that we need to do, get done in an accurate way. And again, that's the point, we both want accurate information. (CHEV1)

**Comment:** We did everything in our power to engage our verifier early. We had them in our office one week after the -- our deadline for submitting the report, and we still were working with our verifier on August 30 and 31st in order to make sure that everything was correct in our report. I would echo the comments of previous folks here, and I'm assuming folks who will speak after me, that the August 1st deadline would pose a large hardship on those producing the report, and runs the risk of errors, et cetera, that could emerge from trying to rush through things. And also, this is not a transitionary problem. It would happen every year, just because of having to coordinate amongst the renewable energy credits and other counterparties, et cetera. So I don't feel it's a issue of transition. (AGR1)

**Comment:** We do have some outstanding concerns. We would echo the concern that I think you've heard today about the verification deadline. We've provided staff with a detailed timeline that demonstrates that every month and nearly every week between January and September is spent organizing, scheduling, presenting, and working through the inevitable iterative process with both verifiers and ARB. And this iterative and robust process is critical to successful verification for complex facilities such as

refineries and oil and gas production. We would echo the comments from Mr. Arita from Chevron in saying that as an alternative, we would propose a compromise of August 15th or we would ask the Board to direct staff to maintain the current verification deadline of September 1st. (WSPA3)

**Comment:** I want to echo the previous comments about moving the verification deadline up by one month. It's not really a transitional issue, because it's a calendar year reporting period. We're supposed to get data up through December 31st. That data doesn't come on December 31st. For electric power importing, it often doesn't come until April, May, even June before we can actually give it to a verifier to verify. So there's very little time in the remaining period after the date is in to get this done. It's not transitional in my mind. And then I'd also like to say that maybe some compromise date would be important or reasonable. (SMUD2)

**Comment:** Basically, what -- what's happening is that each year the reporting requirements get more and more complicated, and -- which requires a more thorough verification. And so you're taking a more complicated report and trying to compress the verification into a shorter time period. And one of the issues for us is an electric power entity, as Tim mentioned, you don't get the data until June. And so you really only have two months if the August 1st deadline is approved. So we actually do request that you either leave it at September 1st or consider doing a bifurcated deadline where you have an earlier deadline for some of the simpler facilities -- not the complicated facilities, but the simpler ones. And that would give staff at least some data, so that they could start doing their work, and then leave September 1st as the deadline for the more complicated facilities and the entity reports. That seems like striking a balance between the needs of staff and the needs of the reporters and the verifiers. (LADWP2)

**Comment:** My name is Sean Neal. I'm here on behalf of the Modesto Irrigation District, or MID. MID similarly opposes -- has concerns with the change in the verification deadline proposed from September 1 to August 1st. MID faces similar challenges of facing a rigorous schedule of site visits and data review. While MID finds -- you know, strives to -- for timely completion of this report, it finds it is often completing the report with, you know, just a few days before the deadline. MID is -- while staff has raised the - described how the Clean Power Plan requirements are similar and synch up with the reporting requirements, MID is concerned and fears that that will not end up being the case in actuality, and such that the change -- that the existing verification deadline would give adequate time to account for both. And similarly to other commenters, we do not believe it's a transitional issue. One report and data input, the electric power entity emissions report, issued -- due June 1st every year creates this as a continuing issue, and -- rather than a transitional issue. I thank you for your time. (MID3)

**Comment:** Good afternoon, Board members. John Larrea with the California League of Food Processors, continuing along the line of verification date changes. As you know, the food processors, their seasons are about 90 days. They run from July through September. So this verification change is kind of like taking those -- pushing us out of the smoke-filled room and into the fire room. (CLFP1)

**Comment:** Sarah Taheri with the Southern California Public Power Authority, or SCPPA. SCPPA is a joint powers authority that is comprised of 12 public power members, including the largest municipal utility and the largest irrigation district in the nation. Today, I simply want to echo comments from several parties regarding the one month shift of the verification reporting deadline. This is problematic for several of our members, and so we simply request that the Board work with staff to consider other options or keep the existing deadline of September 1st. With that, thank for your time and consideration. (SCPPA1)

**Comment:** I'm echoing just about everybody else's concern about the movement of the MRR deadline up. We do our best. We work with our verifiers ahead of time. There's a lot of back and forth, and a lot of detail that goes into it, and we want to make sure that our report is complete and accurate. And we believe we deliver that accurate product, but it takes the time. (SVP1)

**Comment:** I want to echo the comments by most of the compliance entities and organizations representing compliance entities today with regards to the deadline. At this point, the MRR rule moving forward adds complexity. This complexity adds time. Moving that deadline back and taking that month away is going to create an additional compliance risk for a number of organizations. We'd like to offer our assistance working with ARB staff moving forward. At this point, even in the workshops prior to this, I don't believe any compliance entity has supported this deadline change. And we think that perhaps it should be workshopped moving forward, and we can come to some sort of compromise that works for all parties involved. (CCEEB2)

**Comment:** As with past speakers, we ask that the ARB not change the verification deadline from September 1st to August 1st, which would further strain efforts to complete the verification process by the allotted deadline. (CMUA1)

**Comment:** This section proposes to change the annual due date for future verification reports to August 1 from the current deadline of September 1. CCMEC considers that moving the date one month earlier to August 1 is highly problematic and burdensome to the cement industry, because most operators have limited environmental staff available to prepare these reports, and the majority of cement manufacturers have had a difficult time obtaining experienced verifiers to meet the current deadline of September 1. This is especially difficult when CARB changes the verifier guidance, which causes the verifiers to re-examine the recordkeeping or monitoring systems that passed the prior year. Although we understand CARB's desire to obtain data as early as possible, many producers will have difficulty meeting this accelerated deadline. Thus, CCMEC recommends that the submittal date continue to be September 1. Alternatively, CCMEC requests that CARB make recommendations and change requirements to expedite the ability of reporters to initiate the process sooner. (CCMEC1)

**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 past<sup>1</sup>.

<sup>1</sup> An on-site verification must be performed by all entities during the first data year of a new compliance period

(MID1)

**Response:** In the 45-day amendments released in July 2016, staff proposed to move the verification deadline from September 1, to August 1, for the reasons described below. Based on stakeholder comments that were received at the first Board hearing in September 2016, the Board directed staff to review whether any additional time could be provided to complete verification. Based on Board direction and staff evaluation, staff moved the verification deadline to August 10<sup>th</sup> in the second 15-day amendments proposal, as described in this response. This revision provides reporting entities and verifiers with 10 more days than the initial proposal, while also giving MRR and the Cap-and-Trade Program sufficient time to reasonably perform quality assurance checks, calculations, analysis, and the data notifications and postings needed to complete all mandated activities under the Cap-and-Trade Regulation.

This additional time 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. The revised deadline still provides covered entities sufficient time to review their compliance obligations, assess how many allowances they receive, and make arrangements to acquire any additional compliance instruments needed for timely compliance. This additional time prior to the November 1 compliance deadline seeks to avoid situations as encountered in the past, where entities identified an error in their reported emissions just prior to the Cap-and-Trade compliance deadline, leaving staff little time to address the issue, have the entity get the emissions reported correctly and verified, and putting the entity in jeopardy of being out of compliance with the Cap-and-Trade Regulation. The net result is that reporters have 8 months and 10 days to report and verify their emissions, leaving ARB staff about two and half months to process the information and distribute millions of dollars in allowance value to over 250 reporters and assign millions of metric tons of emissions to covered entities.

One commenter stated that other program commitments do not allow for ARB verifications during early summer. ARB encourages reporting entities to begin the contracting and verification process with verifiers as soon as possible in the calendar year to avoid some overlapping with other program commitments. Reporting entities may also wish to identify verifiers without scheduling conflicts to ensure verifications are completed by the deadline.

One commenter also noted that, currently, a majority of the verifications are completed by a relatively small number of verifiers. Staff does not believe this is problematic for a change in deadline. First, the number of verifications completed by a given lead verifier is not necessarily a reflection of workload, since lead verifiers may receive assistance from other accredited verifiers, including qualified subcontractors. Reporting entities and verifiers can also begin the verification process sooner in the reporting year to facilitate earlier completion or to accommodate summer workload. For instance, VB selection, contracting, COI submittal and approval, and initial verification planning, can begin prior to the reporting entity submitting its emissions data report. In calendar year 2016, ARB received only approximately 20 percent of the required COI forms prior to the reporting deadlines, and over 60 percent of the required site visits were not performed until June or later. These percentages for 2016 represent an improvement over prior years, which has resulted in a streamlining of the verification process for the reporting entities and verification bodies that completed these steps early.

Additionally, it is expected that some verifiers and verification bodies will perform a large number of verifications, as these verifiers benefit from economies of scale, and choose to make ARB verifications a larger portion of the work they do. Lastly, reporting entities are encouraged to seek assurance from their verifiers that they will be able meet the August 10th deadline. Likewise, verification bodies may bring on additional staff as needed, including qualified and accredited subcontractors. ARB has informally surveyed existing verification bodies that have not previously provided services to petroleum refineries, which is among the most complex industry sector. Several have clarified to ARB verification staff that they are available to provide verification services and have similar experience and expertise as verification bodies that are already providing services to these sectors. Staff continues to monitor verifier availability and will offer additional training opportunities, as warranted.

We believe that the August 10th deadline can successfully be attained by reporters and verifiers if they do not wait well into the year to report and to select and contract with a verification body, begin the verification immediately after the completed reports are submitted, and maintain consistent engagement throughout the verification process. Staff continues work with stakeholders to identify efficiencies that could be implemented by both ARB staff and the

reporting entities to ensure a more streamlined reporting and verification process to support this proposed deadline change.

Regarding the comment that ARB acquire additional staff or reconfigure staff assignments to assist in meeting Cap-and-Trade Program and other deadlines (versus changing the verification deadline), it is not realistic or feasible to perform short-term hiring or staffing reallocations, considering the resources required for training, security clearances, and the sensitivity of the work required, just to support increased workload during a two-month period.

ARB staff disagrees that verifications will be less rigorous, with the result being less accurate data being reported to ARB. When faced with a shorter time period to report accurate data, reporting entities could adjust their schedule and more promptly address data quality issues identified by the verifier or ARB.

ARB disagrees that the verification deadline shift requires analysis under CEQA. The approximately three-week change will not result in less rigorous testing, nor does it change facility reporting obligations. It is unclear that such changes, even if they did occur, would have environmental impacts, given the reporting-focused purpose of this program. In any event, there is no evidence that deadline shifts of this sort lead to any foreseeable environmental impacts – instead, they will simply affect time spent reporting and verifying data. This deadline change therefore does not have a significant environmental impact for purposes of CEQA.

ARB agrees that we should continue to take steps to ensure Cal e-GGRT, guidance documents, and other administrative tasks are completed and available more promptly to aid reporting entities in completing reporting and verification by the applicable deadlines. ARB has already begun this process by releasing the reporting modules and guidance earlier in the year, and will continue to ensure resources are available in a timely fashion to facilitate earlier reporting and verification.

Several commenters assert that MRR continues to include more reporting requirements over time, which can increase the amount of work verifiers must review each year. While modest additional reporting requirements have been added over the years, the most recent amendments do not impose a significant increase in additional data to be reported and verified, and ARB staff anticipates that most reporting entities will not need additional time to complete reporting.

Several EPEs requested a bifurcated verification schedule, or the ability to apply for a deadline extension, to retain the current verification deadline of September 1st, while other facilities and suppliers would have the proposed revised deadline. While we appreciate this suggestion, this proposed solution would not address ARB's implementation issues for assessing timely compliance obligations under the Cap-and-Trade Program as stated above.

Finally, some comments also suggest moving deadlines established in the Cap-and-Trade Program, rather than the verification deadline, under the mistaken assumption that the Cap-and-Trade deadlines are more flexible. Staff disagrees that these Cap-and-Trade deadlines are more flexible. Given the coordination needed for a linked Cap-and-Trade Program, these deadlines are not a simple thing to change, and moreover, MRR data and Cap-and-Trade compliance information is made available publicly after the surrender deadline. Moving the Cap-and-Trade deadlines would push back the release of this public data at a time when AB 197 is seeking additional data transparency. Staff does not want to further delay the availability of data to interested stakeholders and believes the proposed change in the verification deadline balances the need for credible verified data to inform a market program, the need for timely compliance, and publication of emissions data. Furthermore, these comments are outside the scope of this rulemaking, and were not proposed for modification in the Cap-and-Trade Regulation as part of the rulemaking to amend that regulation.

## **E-2. Multiple Comments: *Consideration of Verification Deadline in Staff Report***

**Comment:** We are also disappointed in the lack of transparency in the Staff Report: Initial Statement of Reasons for Rulemaking (ISOR), dated July 19, 2016, on this verification deadline issue. The Staff Report (ISOR, page 5) states that it does not have “sufficient time to reasonably perform quality assurance checks, calculations, analysis, and the data notifications and postings needed to complete all mandated activities under the cap-and-trade program.” Currently, reports are submitted to ARB on April 10th (and some on June 1st). Therefore, ARB has the opportunity to conduct independent data checks well before the September 1st deadline. ARB has no need to hold off in-depth reviews to post-September 1st.

The Staff Report (ISOR, page 5) states “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 1st Cap-and-Trade Regulation compliance deadline.” ARB has been issuing Cap & Trade allowances and assessing obligations for the past three years. ARB has been able to meet all reporting required under the Cap & Trade program. It would be reasonable to assume that the knowledge gained with each passing year that allowances are allocated must have resulted in reduced cycle-time, thus enabling staff to issue allowances more efficiently each subsequent year.

Finally, the Staff Report (ISOR, page 5) states that “This additional time will provide covered entities 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.” We fail to follow this logic because ARB is not proposing any changes to the Cap & Trade deadlines related to allowance allocation deadlines or to compliance obligations. (WSPA1)

**Comment:** M-S-R Strongly Opposes the Proposed Change to the Verification Deadline. The proposal to accelerate the verification deadline has the potential to compromise the accuracy of the reports and verifications submitted, ultimately resulting in greater overall inefficiencies. The Staff Report notes that this change is necessary "to support implementation of the cap-and-trade program. Currently, obtaining the necessary verified data on September 1 does not provide ARB staff sufficient time to reasonably perform quality assurance checks, calculations, analysis, and the data notifications and postings needed to complete all mandated activities under the cap-and-trade program." (Staff Report, p. 5) The Staff Report also claims that the "no action alternative" was not included because it would not allow for "timely and efficient implementation of the cap-and-trade program, and therefore, would not be more or as effective in carrying out the purpose for which the revisions are proposed." The Staff Report concludes that the change "would be no less burdensome overall, to affected private persons than the proposed revisions" because compliance entities while the change in 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." (Staff Report, p. 10) M-S-R disagrees with this conclusion, and unfortunately, this rationale does not aid compliance entities in carrying out their reporting obligations, nor does it provide verifiers the time necessary to complete the verification. (MSR1)

**Response:** Staff maintains the need for an earlier verification deadline for improved administration of both the MRR and the Cap and Trade Program. As noted in the staff report, ARB staff does not have enough time to perform suitable quality assurance checks, calculations, analysis, data notifications and postings in order to ensure sufficient time for Cap-and-Trade Program staff to calculate allowance allocation amounts and assess compliance obligations between the September 1 verification deadline and the November 1 Cap-and-Trade Regulation compliance deadline. MRR staff must provide the final covered emissions numbers used to calculate compliance obligations for natural gas suppliers based on verified data, not reported data. Since reported data can change up to and until September 1, staff cannot complete final quality assurance until after all data has been verified. While staff does conduct quality control checks throughout the summer on reported data, the data is not able to be used for the Cap-and-Trade Program until after the verification deadline has passed and there are no more changes to that data by operators. MRR staff must provide final covered emissions numbers to the Cap-and-Trade staff before the end of September to allow the Cap-and-Trade staff to review the data and work with MRR staff on assessing the final compliance obligation. That number is then input into the Compliance Instrument Tracking System Service (CITSS) in mid-October, which only gives compliance entities a few weeks to see their actual compliance obligation, work with ARB staff if there are any issues, and comply. To ensure that entities are not in a position of not being able to comply with the surrender obligations under the Cap-and-Trade Program, ARB staff believes it is important to make the compliance obligation number available to

covered entities earlier. The additional time gained by moving the verification deadline from September 1 to August 10 will ensure that ARB staff has sufficient time to review and calculate compliance obligations, and to provide with earlier access to their actual compliance obligation number earlier such that they will have sufficient time to determine how they will comply with the Cap-and-Trade Program.

Moreover, one commenter suggests moving deadlines established in the Cap-and-Trade Program, rather than the verification deadline. Given the coordination needed for a linked Cap-and-Trade Program, and the requirement to publicly post MRR data and Cap-and-Trade compliance information after the surrender deadline, these deadlines are not a simple thing to change. Moving the Cap-and-Trade deadlines would push back the release of this public data at a time when AB 197 is seeking additional data transparency. Staff does not want to further delay the availability of data to interested stakeholders and believes the proposed change in the verification deadline balances the need for credible verified data to inform a market program, the need for timely compliance, and publication of emissions data. Furthermore, these comments are outside the scope of this rulemaking, and were not proposed for modification in the Cap-and-Trade Regulation as part of the rulemaking to amend that regulation.

### **E-3 Comment: *Additional Data Collection for Verification Deadline Change***

If ARB changes the verification deadline from September 1 to August 1, First Environment proposes the following additional revisions to the regulation to facilitate successful verifications by the earlier date:

1. Relative to 95105, establish requirements for uploading specified supporting documentation to Cal e-GGRT at the time the GHG report is submitted. We propose, at a minimum, that this documentation should include but not be limited to:
  - a. Statement on operational control and related entities
  - b. Electricity purchases/acquisition records
  - c. Natural gas purchases/acquisition records
  - d. Evidence of unit nameplate capacities
  - e. Air district permits
  - f. Internal meter calibration records
  - g. Gross and net generation data
  - h. Thermal energy generation data
  - i. Product data evidence
  - j. Records associated with any issue ARB defines as a high risk issue (e.g. contracts for biomass derived fuel)
  - k. Specified source contracts for EPEs
  - l. Specified source generation meter data for EPEs The verification body should be provided access to these uploaded documents through Cal eGGRT when the reporter selects the verification body in Cal eGGRT to provide verification services.

2. Relative to 95105(c) and 95105(d), establish requirements for uploading these documents to Cal eGGRT, which will encourage reporters to prepare for and begin verification activities earlier. We propose establishing a February 30 deadline for uploading these documents to Cal eGGRT.
3. Relative to 95131(a), establish a regulatory deadline for reporters for submission of the NOVS, which will encourage reporters to prepare for and begin verification activities earlier. We propose a May 30 deadline for submission of NOVS.
4. Relative to 95131(b)(3), establish a regulatory deadline for reporters for completion of verification site visits, which will encourage reporters to prepare for and begin verification activities earlier. We propose a June 30 deadline for completion of verification site visits.
5. Relative to 95131(c)(4), recognizing the proposed shortened verification period, reduce the notification and report correction period to five days.
6. Relative to 95133(e), establish a regulatory deadline for reporters for submission of the COI, which will encourage reporters to prepare for and begin verification activities earlier. We propose a May 1 deadline for submission of COI. Without these revisions to the MRR, First Environment requests that the verification deadline remain September 1. (FE1)

**Response:** ARB appreciates the commenter's recommendations on ways to facilitate more timely verification. Many of the changes are beyond of scope of these regulatory revisions. These recommended changes would impose additional interim regulatory deadlines and reporting burdens on reporting entities that could result in non-compliance with MRR. Lastly, the large variety of operators that report under MRR make it difficult to establish requirements for specific documents and materials required for submission, because there is so much variability among different operators, even within the same industry sector.

For these reasons, ARB is unable to make the requested changes. ARB will continue to conduct rigorous outreach to reporting entities to ensure they are prepared to make all requested documentation available to verifiers in a timely fashion.

#### **E-4. Comment: *Section 95130(a) Rotation of Verification Body Requirements***

The existing language under §95130(a) of the Reporting Regulation does not allow reporting entities subject to annual verification requirements to use the same third-party verifier for six consecutive report verifications as was originally intended. We recommend the following edits be applied to the text in order to allow for the six consecutive report verifications by the same third-party verifier.

§ 95130(a). Annual Verification

- (2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifier(s) for ~~a period of more than six consecutive years~~ report verifications, which includes any verifications conducted under this article and for the California Climate Action Registry; The Climate Registry; Climate Action Reserve; or other third-party verifications, validations, or audits conducted under impartiality provisions substantively equivalent to section 95133, which may include third-party certification of environmental management systems to the ISO 14001 standard or third-party certification of energy management systems to the ISO 50001 standard. This limitation applies only to those third-party verifications, validations, or audits that include the scope of activities or operations under the ARB identification number for the emissions data report.

~~The six-year period begins on the date the reporting entity or its agent first contracts for any third-party verifications, validations, or audits under any protocols, including ARB verification services, for the scope of activities or operations under the ARB identification number for the emissions data report, and ends on the date the final verification statement is submitted.~~

~~Verification bodies may not provide verification services if the six-year period ends prior to sixty days after the emissions data report is certified by the reporting entity, unless a verification plan~~

~~is agreed to by the reporting entity, the verification body, and the Executive Officer. IF the six-year time limit is exceeded, the reporting entity must engage a different verification body and meet the verification deadline. Even if these services are provided before the verification body or verifiers have received ARB accreditation, the six-year period still begins when these services are contracted for, if accreditation is later received.~~

The ~~six-year~~ limit also applies to verification bodies and verifiers providing ARB or any other third-party verifications, validations, or audits that include the scope of activities or operations under the ARB identification number for the emissions data report and does not reset upon a change in reporting entity ownership or operational control.

- (3) If a reporting entity is required or elects to contract with another verification body or verifier(s), the reporting entity may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifier(s) for at least three years consecutive verifications.

- (A) If a reporting entity is required to select a new verification body to verify an emissions data report(s) that has been set aside pursuant to section 95131(e), the reporting entity may continue to contract for verification services with its current verification body, subject to the six-year time limit set forth in 95130(a)(2).

(CASA1)

**Response:** The comments are out of scope of these regulatory changes, as staff is not proposing to change the amount of time or number of consecutive verifications a verification body can provide verification services to reporting entities. However, to clarify the existing requirements, staff would like to clarify that section 95130(a) does not preclude a reporting entity from engaging with a verifier for up to six years for six verifications. Reporting entities may engage with the same verification body for six calendar years, beginning with the date the verification body first provided professional services and ending on the date the verification body submitted their final verification statement and verification report. Within that time period, the verification body is not restricted on the



number of calendar year verifications they perform. They may verify more than six years in cases of set aside verification statement(s) from prior years, or where verification bodies can provide assurance to ARB that a 7<sup>th</sup> verification year can be completed within 6 years.

#### **E-5. Multiple Comments: *Section 95130(a)(2) – 6-year Verifier Rotation Requirements***

**Comment:** And then finally, we ask that ARB extend the time the same verification body can provide services. Right now it's 6 years. We hope that could be increased to 12 years. These services are in high demand. The people who get to know our systems, that takes time too. The turnover takes even more time. And so especially with potential other AB 32 regulations requiring verification, like potentially LCFS, we hope that you'll consider extending from 6 to 12 years. ARB has a robust vetting program anyway, and this change will not impact the integrity or success of the MRR program. (PGE2)

**Comment:** Another change to requirements for verification services in 95130(a)(2) states, "Verification bodies may not provide verification services if the six year period ends prior to sixty days after the emissions data report is certified by the reporting entity, unless a verification plan is agreed to by the reporting entity, the verification body, and the Executive Officer. If the six-year time limit is exceeded, the reporting entity must engage a different verification body and meet the verification deadline." WSPA believes this restricts the number of reports a single verifying body may be able to verify from six data years of reports to only five if the timing window does not fall in the right timeframe. Given the relatively scarce supply of verifiers available to certify refinery reports, WSPA does not support the new proposed language that further restricts the available options for refinery report verifiers. WSPA believes ARB's intent for the six year restriction was not based on a problem with having six calendar years verified by the same body, but actually by having the verifying body perform services too many times. As such, WSPA requests that reporting parties be able to use the same verifying body six times and that the proposed language be removed. (WSPA1)

**Comment:** The number of independent, third-party verifiers available since the MRR was initially adopted has reduced significantly and only a limited number of verifiers have demonstrated sufficient expertise to understand PG&E's multiple and complex business operations. This has introduced a risk of non-compliance with the MRR because a verifier requires adequate time to understand the variations that exist within PG&E's operations and then complete the verification services in a timely manner. To mitigate these risks, PG&E suggests that ARB consider extending from six years to twelve consecutive years the period of time that a third- party verifier can work with the same entity. Since ARB has a robust program that ensures the quality of verifications, the integrity and success of the Cap-and-Trade Program will not be impacted by this change. (PGE1)

**Comment:** Before considering changes to the verification deadline, CCEEB would like to discuss, in a dedicated technical workshop, additional ways to streamline the

verification process. For example, we think staff should consider upgrades to software, timing of reporting tool availability, extending the 6-year limit for verifiers, ARB and verifier issue arbitration the release of guidance documents during the verification process, and how certain decisions impact the MRR process. (CEEb1)

**Comment:** Additionally, we'd like to request that the relationship time limits with the verifiers be extended beyond that 6 years. It takes a while to learn these facilities. The complex -- especially the larger and more complex facilities. By extending that timeline, we might be able to get some additional efficiencies in how these reports are performed and turned in. (CEEb2)

**Response:** The comments are out of scope of these regulatory changes, as staff is not proposing to change the amount of time a verification body can provide verification services to reporting entities. The changes ARB is proposing clarify how the 6-year requirement is applied in various situations that have come up while implementing the verification program. As discussed in the response to comment E-2 above, sometimes a 7<sup>th</sup> verification is possible within the 6-year timeframe, and staff wanted to clarify how the current rules apply to that situation.

#### **E-6. Multiple Comments: Section 95131(b) *Material Misstatement Requirements for Thermal and Non Thermal Split Field Barrels Data***

**Comment:** WSPA believes that the modification to the definition of “material misstatement” and the changes made to Sections 95131(b) and (14) regarding verification of covered product data require clarification. By eliminating the word “total” from covered product data in the definition of “Material Misstatement,” it could be interpreted that ARB is requiring the verification of all product streams. We understand from our August 11, 2016 meeting with ARB staff that ARB does not intend to require verification for all product streams. Instead, staff indicated that the change is meant to separate material misstatements for different units of measure in alignment with the sector benchmarks. In order to minimize the risk that staff’s intent is misinterpreted by future staff, WSPA recommends that the following alternative language be used for this section:

“Material misstatement” means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that the total reported covered emissions (metric tons of CO<sub>2</sub>e) or total reported covered product data (aggregated to the level of each different benchmark unit of measure used by the reporting entity) contains errors greater than 5%, as applicable, in an emissions data report. Material misstatement is calculated separately for covered emissions and covered product data, as specified in section 95131(b)(12)(A).” (WSPA1)

**Comment:** As currently drafted, Section 95131(b)(12) would double the potential for a material misstatement violation at the field level for “split” fields where both thermal and non-thermal barrels are produced. It makes each category of “barrel”, both thermal and

non-thermal, subject to a separate potential material misstatement rather than a single misstatement for the aggregate field production. Although ARB staff has stated its intent to regulate all industries based on common unit of measure, a more stringent standard is proposed here for oil and gas production, putting owners of split fields at an arbitrary disadvantage compared to others. Fields having only thermal, or only non-thermal, production are not impacted.

The oil and gas sector is already burdened with additional reporting obligations, as it must report both on the basin level and on the field level. Thermal and non-thermal split fields report all product output in a common unit of measure; barrels. Because the production must fall into one or the other subcategory, making the split is a zero-sum game. An inadvertent error in one subcategory creates a concomitant error in the opposite direction in the other subcategory.

The proposed application of the material misstatement standard individually to thermal and non-thermal barrels creates a double jeopardy for the producer. This creates a blatant disadvantage for the owner of a split field vis-à-vis those who own fields having a single subcategory of production. A small, non-material error in one subcategory can lead to an amplified error in the other. For example:

A hypothetical 10,000 barrels/day (bbl/day) field with an assumed: 90% / 10% thermal/non-thermal split and 95% meter accuracy, could be off by no more than 50 bbl/day which would trigger a material misstatement. If the split field had a 99% / 1% split and the same volume and accuracy, the measurement could not be off by more than 5 barrels. On the basis of 10,000 bbl/day total production, neither the 50 bbl (0.5%) or the 5 bbl (0.05%) errors are material, yet both would trigger material misstatement criteria as written. Therein resides the patent unfairness of the proposed double-standard.

In addition to doubling potential for misstatement and fines, the example above shows that the proposed change is likely to result in very little gain in data accuracy. However, it doubles the work of the verifier in the product verification process, a service that comes at additional cost.

WSPA opposes the proposed change which disadvantages some operators and our industry sector over others. ARB should apply the same requirement to oil and gas production as all other sectors - material misstatement based on units of measure, in this case barrels. (WSPA1)

**Comment:** Let me turn to a couple of other more technical items. Another concern for us is the material misstatement requirements. As it's currently drafted, the proposed amendment would double the potential for material misstatement violation at the field level, where both thermal and non-thermal barrels are produced. It makes each category of barrel, thermal and non-thermal, subject to a separate potential material misstatement, rather than a single misstatement for the entire field. And although ARB staff has stated its intent to regulate all industries based on a common unit of measure,

a more stringent standard is being proposed here for the oil and gas industry putting owners of split fields, the thermal and non-thermal fields, at an arbitrary disadvantage. (WSPA3)

**Response:** The rationale for requiring separate material misstatement evaluations for thermal and non-thermal product data is due to the fact that the two categories have different benchmarks under the Cap-and-trade Regulation. From the perspective of allowance allocation in the Cap-and-Trade Program, crude oil produced using thermally enhanced oil recovery is a different product compared to crude oil produced using techniques other than thermal enhancement, and the former receives an allocation of allowances that is ten times the allocation of the latter. Therefore, categorizing the total amount of oil produced from “split fields” is not a “zero-sum game,” as described in the comment, because non-thermal crude oil should not be reported as thermal crude oil, and vice versa. It is appropriate to require accurate reporting that is in conformance with MRR for the quantities of crude oil reported in each category. As noted in the Initial Statement of Reasons to this rulemaking, this requirement will not take effect until the 2019 data year (2020 reporting year) to ensure that reporting entities have sufficient time to adapt to these requirements, including changing metering if necessary.

Staff appreciates the effort by reporting entities and verifiers to ensure accurate data reported from “split” fields with thermal and non-thermal oil production. ARB does not agree that the proposed revision would double the work of the verifier in the product data verification process. Verifiers are required to determine the appropriate amount of data review needed to reach reasonable assurance of no material misstatement. Reporting entities can ensure an expedient verification process by having an appropriate monitoring plan and methodology for determining thermal vs non-thermal separately. Furthermore, ARB disagrees that the proposed revisions “would double the potential for a material misstatement violation.” MRR requires all correctable errors to be fixed, so most discrepancies should be addressed before the verifier’s final calculation of material misstatement. Also, because covered product data may be excluded if not reported accurately, ARB does not envision that reporting entities would receive an adverse product data verification statement, as a result of this revision. As such, staff declines to make the proposed revision to modify the definition of material misstatement to include the term “total” when referring to covered emissions or covered product data. As the commenter noted, that modification was made to ensure that the material misstatement assessment was performed based on units of measurement. As noted above, staff does not expect this modification to increase substantially the amount of work required by verifiers of reporting entities with “split” fields. However, verifiers are expected to reach reasonable assurance that the product data was reported accurately, and that the methodology for determining thermal vs. non-thermal production is consistent with regulatory requirements.

**E-7. Comment: 95131(b)(7) Adding New Risk Evaluations to Verification Process**

Section 95131(b)(7)(B) has proposed language to evaluate “risk of incomplete reporting” for fuel and electricity data. WSPA does not support this change as there is no auditing standard by which risk of incomplete reporting can be evaluated. Thus, this new requirements can be interpreted much differently by each verification body. By removing this change, ARB avoids (reduces risk of) inconsistent and indefensible risk evaluations. (WSPA1)

**Response:** Generally accepted auditing standards applicable to both environmental and financial audits include a review of omissions to ensure all reportable data is indeed reported. ARB already requires verifiers to review omissions in their evaluation of material misstatement in §95131(b)(12). However, staff has identified that not all verification bodies document that review in their sampling plan and data checks. The proposed revision requires that, for fuel suppliers and electricity importers, verification bodies indicate in their sampling plan that they have reviewed the risk of incomplete reporting. The revision is written to apply to fuel suppliers and electricity importers because those two sectors keep large volumes of data, which must be filtered and queried to determine reportable transactions, raising the risk of omitted reportable transactions. Under this revision, verifiers are still required to review omissions for all other sectors, but are only required to document that review explicitly in the sampling plan for these two sectors.

**E-8. Multiple Comments: *Provide Incentives for Advanced Reporting and Verification***

**Comment:** And we stated there that if ARB does move the deadline, we have some suggestions in those written comments that you might want to consider, for example, providing incentives for advanced reporting and verification, and then maybe even recognition of good faith efforts by obligated parties to provide timely compliance that is otherwise compromised because of the deadline change. (CPC2)

**Comment:** Good afternoon, Board members. John Larrea with the California League of Food Processors, continuing along the line of verification date changes. As you know, the food processors, their seasons are about 90 days. They run from July through September. So this verification change is kind of like taking those -- pushing us out of the smoke-filled room and into the fire room. So we are really looking for -- you know, in the end, I've made the suggestion before, and I think it's still valid is that if you could incentivize some of this, you might find that you'd find a lot of the smaller companies that don't require as much verification moving much quicker. So I call it kind of like the early-bird registration. You know, you get a little bit off, if you register early. So if you set like an incentive date of June 1st, companies like ours could probably get this done, and get it verified, and signed off by CARB well before that. And as part of the incentive, they'd get their allowances early, as opposed to waiting for the entire thing to happen. It would also help the verifiers, because they'd be able to identify those companies are willing to move very, very quickly and allow them to maybe associate better timing with

it, so that they could, you know, not be so rushed at the very end, because I suspect that for most of the companies like ours, you know, the more complex ones they start off on January 1st, and they take up all the time, and then we get left at the end, because they've got to be able to deal with those more complex issues. And so then it's a big rush for us, and it's right in the middle of our season. So I'd -- you know, please take a look at policy incentivizing this. I'd appreciate that. (CLFP1)

**Response:** This change was not incorporated in the proposed revisions or included in the notice of changes, so it is out of scope and we are unable to make the revision at this time. This comment is out of scope because allowance allocation is not handled under MRR, but rather the Cap-and-Trade Regulation. However, staff notes that nothing prevents entities from having their data reported and verified before the reporting and verification deadlines.

**E-9. Comment: *Eliminate Adverse Verification as Result of Non-Covered Emissions***

Finally, I'll just say, we strongly support the amendment to eliminate the risk of an adverse verification as a result of reporting errors that are not linked with covered emissions. This is going to allow us to focus on the right things. (PGE2)

**Response:** Staff appreciates support for the change.

**E-10. Multiple Comments: *Availability of ARB-Accredited Verifiers***

**Comment:** We also recommend that the ARB continue to encourage and develop a large pool of accredited verifiers, which could reduce challenges in meeting verification deadlines. (CMUA1)

**Comment:** 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. (CALPINE1)

**Comment:** 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. (MWDSC1)

**Comment:** CCEEB would like to better understand the reasons for the diminishing pool of verifiers. The pool of ARB-accredited verifiers has declined annually since the MRR

verifications were first required in 2010. In 2015, 25 companies verified over 500 MRR reports. With its proposal to advance the verification date to August 1st, ARB would further exacerbate the present challenges associated with completing the verification process in a timely manner. We are also concerned with the reduction in the pool of accredited verification companies as there may be insufficient skilled personnel available to perform verifications. ARB should explore ways to prevent further decline in the number of verifiers and bring additional verification bodies into the program. We believe it would be worthwhile if ARB invited some of the verifiers no longer in the market to provide input to help understand why they made the decision to discontinue providing these services. This information could help address the root cause of why companies are leaving the California programs and make adjustments, as appropriate. ARB should also reach out to the current pool of verifiers to hear their perspective on what changes might be needed to ensure the feasibility of any modifications to the verification deadline. (CCEEB1)

**Comment:** ARB appears unaware that there is a lack of available verification firms that meet corporate business tests for contracting, are qualified to verify all areas of our facilities, and are willing to work as verifiers which then precludes them from competing for the provision of other services. Further given the specialized nature of some facilities (such as oil and gas facilities), it cannot be assumed that every verifier on the approved verifier list is appropriate or qualified for every facility type. (WSPA1)

**Response:** Staff appreciates stakeholder feedback on verifier scheduling and availability. ARB currently has 32 accredited verification bodies, and 220 accredited verifiers. ARB recognizes that not all verifiers are accredited to provide verification services for all sectors. However, as a result of this and similar comments, staff informally surveyed existing verification bodies that have not previously provided services to petroleum refineries. Several have clarified to ARB verification staff that they are available to provide verification services and have similar experience and expertise as verification bodies that are already providing services to these sectors. Staff continues to monitor verifier availability and will offer additional training opportunities, as warranted.

#### **E-11. Multiple Comments: *Extending Allowance Allocation Date***

WSPA has offered alternatives that would allow for maintaining the September 1st verification deadline while providing ARB more time to make its cross-check calculations by pushing out the November 1st allowance allocation date. Disappointingly, ARB staff dismissed the suggestion that the deadline for allowance allocations be moved from October to December because “it would interfere with the holidays”. (WSPA1)

**Comment:** We represent business and taxpayer organization. And mainly, we just really wanted to comment basically back to slide 12, upon review of the MRR, we are opposed to changing the verification deadline to August 1st. We believe that moving that deadline is going to create a significant burden for both reporting entities and

verification bodies. So we recommend leaving it at the current deadline. And if we need to, maybe push back the cap-and-trade deadlines, because they appear to be more flexible. We did submit our written comments today as well. And we stated there that if ARB does move the deadline, we have some suggestions in those written comments that you might want to consider, for example, providing incentives for advanced reporting and verification, and then maybe even recognition of good faith efforts by obligated parties to provide timely compliance that is otherwise compromised because of the deadline change. (CPC2)

**Response:** This comment deals with provisions under the Cap-and-Trade Regulation, and is therefore out of scope for this MRR rulemaking. See also Response to Comment E-2 in Section IV of this document for the 45-day comments.

## **F. Electric Power Entities**

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### **F-1. Multiple Comments: *Proposed Removal of RPS Adjustment***

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.<sup>4</sup> Pacific Gas and Electric Company (PG&E) has estimated that 50% of its current load will depart for CCAs in the future.<sup>5</sup> 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. (CCA1)

**Comment:** It may not be feasible to associate RECs with electricity "not directly delivered to California" §95105(d)(6). ARB staff is proposing to add the following to the Electric Power Entity GHG Inventory Program recordkeeping requirements: to show *how the entity determined that electricity associated with REGs claimed for the RPS Adjustment credit was not directly delivered to California, if reporting an RPS Adjustment*. This proposed recordkeeping requirement is not feasible for the following reasons: 1) The owner of the RECs may not have access to documentation showing where the electricity ("null" power) went after it was sold to another party, and 2) There is a disconnect between hourly E-tags (used to document electricity delivery) and RECs (in the form of monthly certificates), and the two cannot be associated on an hourly basis. LADWP recommends this proposed amendment be withdrawn because it is not feasible to comply. (LADWP1)

**Comment:** The revisions to section 95111(g) are linked to proposed program changes dealing with the RPS Adjustment, which is the subject of extensive comments by

stakeholders. M-S-R asks that the Board direct staff to strike this proposed amendment and to address potential revisions to the MRR commensurate with proposed changes to the Cap-and-Trade Program Regulation in 15-day changes. (MSR)

**Comment:** The ARB Should Retain the Renewable Portfolio Standard Adjustment Post-2020. 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.”<sup>15</sup>

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.”<sup>16</sup> 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.

<sup>15</sup> ARB Staff Report, p. 53

<sup>16</sup> ARB Staff Report, p. 53

(ORA1)

**Comment:** The Office of Ratepayer Advocates (ORA) provides the following comments intended to support the alignment of ARB’s proposed amendments to the regulations with the state’s current and future policies for reducing GHG emissions. ORA focuses in particular on developing strategies that minimize the cost impact on California’s ratepayers, while maximizing the benefits from their investments in current and future programs to achieve the state’s GHG reduction goals.

ARB should align its current Cap-and-Trade accounting rules with California's Renewable Portfolio Standard (RPS) Program.

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.<sup>2</sup> The RPS statute identifies the electricity products that are eligible to comply with the RPS procurement requirements.<sup>3</sup> The CPUC and the CEC track RPS procurement through Renewable Energy Credits (RECs) that are assigned to eligible renewable generation.<sup>4</sup> 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 unbundled RECs.<sup>5</sup>

Under ARB's Cap-and-Trade program, entities that import electricity to California are responsible for the GHG emissions associated with those imports.<sup>6</sup> If the imported electricity is procured from a "specified"<sup>7</sup> 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"<sup>8</sup> source, then the emissions compliance obligation is determined by multiplying a default emission factor (0.428 MTCO<sub>2</sub>e/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,<sup>9</sup> 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."<sup>10</sup>

<sup>11</sup>

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.<sup>12</sup> The power that serves load in California procured as PCC2 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.<sup>13</sup>

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 response to ARB’s questions at the ARB/Joint Utilities Group meeting held in March of 2016.<sup>14</sup>

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.

<sup>13</sup> Public Utilities Code Section 399.11 (a).

<sup>3</sup> Public Utilities Code Section 399.16.

<sup>4</sup> Public Utilities Code Section 399.21.

<sup>5</sup> Public Utilities Code Section 399.16.

<sup>6</sup> 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 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>.

<sup>7</sup> “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).

<sup>8</sup> “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*

<sup>9</sup> The RPS adjustment is calculated as the product of the default emission factor for unspecified sources factor (0.428 MTCO<sub>2</sub>/MWh) multiplied by the amount of imported electricity subject to specific requirements under ARB’s regulations. *Ibid*.

<sup>10</sup> 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.

<sup>11</sup> 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.

(F) Only RECs representing electricity generated after 12/31/2012 are eligible to be used towards the RPS adjustment.

<sup>12</sup> 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."

<sup>13</sup> 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.

<sup>14</sup> [https://www.arb.ca.gov/cc/capandtrade/meetings/informal/pg\\_e\\_comment\\_7.pdf](https://www.arb.ca.gov/cc/capandtrade/meetings/informal/pg_e_comment_7.pdf)

\* \* \*

Conclusion. Both the RPS and Cap-and-Trade programs are designed to combat climate change. Through these programs, the electric sector currently makes significant contributions toward meeting California's GHG reduction goals. The ARB's regulations should recognize and enhance the value that customers provide through their electric rates that include the cost of these programs. As explained above, the ARB can do this in two ways. First, the ARB should revise its accounting procedures in order to credit RPS investments intended to reduce GHG emissions so that ratepayers do not pay once for RECs and then again for GHG compliance instruments. (ORA1)

**Comment:** All electricity importers including Generation Providing Entities (GPE) should have to satisfy all four criteria specified in the Cap & Trade regulation to claim a compliance obligation based on a specified source emission factor per §95111(a)(4).

ARB staff is proposing to add the following new requirement: *"A GPE must report imported electricity as from a specified source when the importer is a GPE of that facility."* However, this proposed amendment is not consistent with the existing requirements in section 95852(b)(3) of the Cap & Trade regulation which requires that all four (4) criteria must be met for an electricity importer to claim a compliance obligation based on a specified source emission factor:

*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.*

(A) *Electricity deliveries 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.*

For consistency between the MRR and Cap & Trade regulations, an electricity importer that is a GPE should not be allowed to claim imported electricity as specified unless they meet all four of the criteria for claiming a compliance obligation based on a specified source emission factor . LADWP recommends that this proposed amendment be withdrawn. (LADWP1)

**Comment:** SCE supports the continuation of the RPS Adjustment as currently implemented in the Cap-and-Trade program and Mandatory Reporting Rule. Many of the changes found in these proposed MRR regulatory amendments conflict with the continued operation of that section as stakeholders currently claim it. Detailed recommendations can be found in the California Joint Utility Group (JUG) comments on the Cap-and-Trade proposed regulatory order, however SCE wishes to again affirm its support for the current structure of the RPS Adjustment. (SCE1)

**Comment:** SDG&E Recommendation: Consistent with the need for the RPS Adjustment to recognize the GHG reductions achieved by California utilities, the Board should reject the Staff-proposed change in 95111(g) to cease reporting on the RPS adjustment beginning in 2021. (SDGE1)

**Comment:** In follow up to what Susie said, there are some outstanding issues related to the RPS adjustment. Some of the proposed amendments to the MRR are directly related to that issue. And given that it is unresolved, that we would ask you to hold off on any amendments related to the RPS adjustment, specifically the Sections are 95105(d)(6), 95111(a)(4), and 95111(g)(1)(M)(3). Those amendments are premature, and should not be adopted until this issue has been resolved. (LADWP2)

**Comment:** And with regard to the proposed revisions that would restrict the ability to utilize the cap-and-trade adjustment, and in our estimation comply with the RPS program without added cost, and changes that are aimed at addressing the concerns with the EIM accounting. We ask that those be completely held off until after the substantive underlying issues have been reviewed and assessed, and concluded in the context of the Cap-and-Trade Program regulation, and then the MRR amendments that would be necessary to affect those changes be taken up. (MSR-NCPA)

**Comment:** I also just want to say really quickly that we support the comments made by Susie Berlin regarding the GHG EIM issue, and the RPS adjustment issue. (PGE2)

**Comment:** I'll -- another echo, is about the lesser-than analysis, and implications on the RPS adjustment, the RPS Program and how it's disjointed. And we really need to have things be more congruent with all policies in California. (SVP1)

**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. 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.

MID requests that, in coordination with the Cap-and-Trade rulemaking, the ARB strike any language pertaining to discontinue or limit the ability to report an RPS adjustment. The value of the RPS adjustment to MID's ratepayers is estimated to be \$49.5 million during the span of 2021-2030, based on allowance prices as forecast by the California Energy Commission as part of their Integrated Energy Policy Report. MID's ratepayers already pay a premium for renewable energy to comply with the RPS program and should not also have to pay for a Cap- and-Trade compliance obligation for those same resources. (MID1)

**Comment:** 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.<sup>2</sup> The Utilities implore that Staff reconsider this position, which is inconsistent with both Legislative intent, as described below, but also historical ARB positions.<sup>3</sup> 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)<sup>4</sup> 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

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."<sup>5</sup>

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 retain s 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 transaction s 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."<sup>6</sup> 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.*<sup>7</sup>

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.<sup>8</sup>

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."<sup>9</sup> 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.<sup>10</sup> 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.<sup>11</sup> 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:

- A. Consider cost-effectiveness of these regulations:<sup>12</sup> 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:<sup>13</sup> 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:<sup>14</sup> 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:<sup>15</sup> 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. Staffs proposal fails to recognize the REC as proper evidence that an importer has the right to claim electricity as renewable not only defies Legislative intent, but all commercial expectations of parties transacting under the California RPS Program.

RECs were developed with the explicit purpose of ensuring ownership and accurate accounting of the renewable attributes of power. Indeed, the construct utilized by the California Legislature and the CPUC has been adopted nationally. According to the United States Environmental Protection Agency (US EPA), "If the physical electricity and the associated RECs are sold to separate buyers, the electricity is no longer considered 'renewable' or 'green.' The REC product is what conveys the attributes and benefits of the renewable electricity, not the electricity itself."<sup>16</sup> 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 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.

<sup>2</sup> See RPS Adjustment: Past and Future (December 14, 2015) at p.5 *available at*: <http://www.arb.ca.gov/cc/capandtrade/meetings/20151214/mssb350.pdf>.

<sup>3</sup> See ARB, Climate Change Scoping Plan: A framework for change (2008) at ES-3, ES-13, II, 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 (20 14) at 40-4 1 (recognizing the achievements of the RPS as contributing to climate change goals) and 89 (recognizing the RPS as among "notable groundbreaking climate change initiatives")

<sup>4</sup> 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.

<sup>5</sup> Public Utilities Code §399.16 (b)(2)

<sup>6</sup> Public Utilities Code §399.12 (h)(J)

<sup>7</sup> Public Utilities Code §399.12(h)(2) (emphasis added)

<sup>8</sup> Public Utilities Code §399.13(a)(4)(C) (emphasis added)

<sup>9</sup> CPUC Decision ("D.") 08-08-028, at Ordering Paragraph 1, available at [http://docs.cpuc.ca.gov/word\\_pdf/FINAL\\_DECISION/86954.pdf](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.").

<sup>10</sup> CPUC Decision 08-08-028, at Appendix A-2.

<sup>11</sup> 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.

<sup>12</sup> Cal. Health and Safety Code § 38562(b)(5).

<sup>13</sup> *Id.* at § 38562(b)(6).

<sup>14</sup> *Id.*

<sup>15</sup> *Id.* at §38562(f).

<sup>16</sup> <http://www3.epa.gov/greenpower/gpmarket/rec.htm>

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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.

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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 by the third party verifier prior to the annual RPS Compliance Report deadline of August 1.

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The Utilities are committed to working with ARB staff to more clearly align REC ownership with the ability to claim an RPS adjustment. Doing so will ensure California ratepayers are not forced to fund the procurement of millions of dollars' worth of incremental Cap-and-Trade allowances, despite their prior investments in renewable generation. The RPS adjustment is essential to provide California utility customers the GHG benefit of renewable procurement. We look forward to ongoing discussions about how to resolve this issue for future reporting years and to reduce the burden on both staff and reporting entities. (MID2)

**Response:** In the 45-day amendments to the Cap-and-Trade Regulation, Cap-and-Trade Program staff proposed the future removal of the Renewables Portfolio Standard (RPS) Adjustment with the addition of section 95852(b)(4)(E) which read, "No RPS adjustment may be claimed for electricity or RECs generated after December 31, 2020." However, in response to stakeholder comments, staff withdrew the proposed amendment to remove the RPS adjustment and proposed to retain the RPS Adjustment as currently implemented. Consistent with the withdrawal of section 95852(b)(4)(E), MRR staff withdrew the proposed RPS Adjustment language in section 95111(g) of MRR in the first 15-day modifications.

The RPS adjustment is voluntary, and it is only applicable when the importer 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, the purpose of the RPS adjustment is to allow for a reduction of the compliance obligation for electrical distribution utilities (EDUs) or for entities that import electricity on behalf of EDUs. The RPS adjustment was originally 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. If the electricity was indeed directly delivered, then it may be required to be claimed as a specified source import instead. ARB intends to publish the REC serial numbers for specified source imports and RPS Adjustment claims on the ARB website to ensure transparency.

The commenters suggest that ARB 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 of California. This is inconsistent with the intent of the RPS adjustment and the reasons for its inclusion per the 2010 MRR FSOR,<sup>9</sup> in which ARB states that “RECs play no role in GHG accounting” and “the RPS adjustment applies to electricity that is not directly delivered to California, and therefore is not included in statewide GHG emissions accounting. The RPS adjustment is not a recognition of avoided emissions, but an adjustment to the compliance obligation to recognize the cost to comply with the RPS program” (page 108). The purpose of RPS program is to encourage development of eligible renewable energy; distinct from Cap-and-Trade Program’s role to provide cost-effective GHG emissions reductions. As further indicated in the 2010 MRR FSOR, “ARB does not believe that the purchase of RECS entitles the purchaser to any right to use those avoided emissions to comply with any GHG regulatory program, and that such a right is beyond the scope of the 45-day modifications” (page 110).

Staff has retained the proposed changes to sections 95105(d)(6), 95111(a)(4), and 95111(g)(1)(M)(3) of MRR. These changes simply clarify existing requirements in MRR for documenting the RPS adjustment, for generation-providing entities to report as specified power imported when they are the GPE of that facility, and for reporting REC serial numbers, respectively. In sections 95111(a)(4) and 95111(g)(3) in regards to GPE-imported electricity, staff clarified the requirement to claim a specified source, specifically so that an EPE may not structure imported power transactions in a manner that would identify power as unspecified that was sourced from a generation facility for which the importer is a GPE. The proposed change represents a clarification of the intent of the existing requirement. The intent of these provisions was established in the 2010 MRR FSOR and in subsequent guidance released by ARB. As explained on page 108 of the 2010 MRR FSOR, “when electricity generated by a zero GHG-emitting resource is directly delivered to California, and the electricity importer (1) is a Generation Providing Entity (GPE) defined pursuant to MRR section 95102(a) or (2) has a written power contract for electricity generated by the

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<sup>9</sup> <https://www.arb.ca.gov/regact/2010/ghg2010/mrrfsor.pdf>

facility, the electricity importer must report the delivery as a specified import and may claim zero GHG emissions for the imported electricity (see MRR sections 95111(a)(4) and 95111(g)(3)).” Therefore, staff declines to make the changes suggested by the commenters on requirements for reporting specified electricity for GPEs.

One commenter argued that the proposed changes to section 95111(a)(4) of MRR would be inconsistent with the requirements in section 95852(b)(3) of the Cap-and-Trade Regulation. Section 95852(b)(3) has been proposed for deletion from the Cap-and-Trade Regulation in order to consolidate all requirements related to REC reporting for specified source imports in MRR and ensure consistency with the intent of the RPS adjustment requirements as described earlier in this response. As such, the proposed changes to section 95111(a)(4) do not pose an inconsistency with any section in the Cap-and-Trade Regulation.

With regard to the comments that propose revisions to section 95111(g)(3) to extend the deadline to certify RPS adjustment claims from July 15 to August 1, these comments are out of scope for this rulemaking. ARB proposed changes to this section to remove the reporting requirements, which were later reinstated in a subsequent 15-day amendment package. Staff did not propose changes to the deadline mentioned in the comment. In addition, verifiers need time to review the data submitted by EPEs prior to the verification deadline. Moving the deadline to certify RPS adjustment claims back to August 1 would not provide sufficient time for verifiers to review the final emissions data report and issue findings prior to the verification deadline, which is proposed in this rulemaking to change to August 10.

## **F-2. Multiple Comments: *REC Serial Numbers and Direct Delivery***

Proposed Amendments related to reporting REC serial numbers should not be adopted. The proposed amendments would remove the requirement to report the REC serial number for certain transactions, consistent with staff’s proposal to eliminate the requirement proposed for section 95852(b)(4) of the Cap-and-Trade Program Regulation. The revisions to section 95111(g) are linked to proposed program changes dealing with the RPS Adjustment, which is the subject of extensive comments by stakeholders. M-S-R asks that the Board direct staff to strike this proposed amendment and to address potential revisions to the MRR commensurate with proposed changes to the Cap-and-Trade Program Regulation in 15-day changes. (MSR1)

**Comment:** SDG&E recommends that the Board reject the changes to section 95111(g)(1) of the MRR that indicates the provision of Renewable Energy Credits (RECs) is optional for direct delivery of out-of-state renewable electricity. Instead, the Board should require that RPS-compliant RECs be bundled with the electricity for it to be considered directly delivered. The MRR should not explicitly indicate that

violating the regulation is allowable as is proposed. SDG&E proposes revisions to Sections 95111(a)(4) and (g)(3) of the MRR to ensure the requirements for a specified source claim are consistent with the Cap-and-Trade regulation.

SDG&E Recommendation: The Board should reject Staff-proposed changes to 95111(g)(1)(M)(3), and instead adopt the following clarifications to sections 95111(a)(4), 95111(g)(1)(M), and 95111(g)(3):

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

(A) Claims of specified sources of imported electricity, defined pursuant to section 95102(a), are calculated pursuant to section 95111(b), must meet the requirements in section 95111(g) and in section 95852(b)(3) of the cap-and-trade regulation, and must include the following information...

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Section 95111(g)(1)(M): Requirements for Claims from Eligible Renewable Energy Resources. Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

1. RECs associated with electricity procured from or generated by an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.
2. RECs associated with electricity procured from or generated by an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.
3. For imported electricity from a specified source which is an eligible

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

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Section 95111(g)(3): *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 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)(1)(M); 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 renewable energy resource then the electricity importer must have (1) a right of ownership or contract rights to the associated RECs; and (2) report the REC serial numbers associated with the imported electricity pursuant to section 95111(g)(1)(M).

(SDGE1)

**Comment:** Turlock Irrigation District (TID). The ARB should remove the proposed amendments to Section 95111(b)(1)(m)(3), which would clarify that the REC serial number reporting requirement will not be enforced by the ARB. This change 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". Green Attributes is defined to include the emissions attributes of renewable resources. This signal will also exacerbate the direct delivery concerns the ARB has faced in implementing the RPS adjustment requirements.

The WREGIS operating rules define a REC to include all Renewable and Environmental Attributes", which includes "any and all credits, benefits, emissions reductions, offsets and allowances-howsoever titled-attributable to the generation from the Generating Unit, and its avoided emission of pollutants." (emphasis added). In other words, while RECs cannot necessarily convey a right to claim avoided emissions in a cap-and-trade program, but the holder of the REC has a contractual right to claim the emissions attributes over other counterparties that may have purchased the null power from the facility. The ARB should recognize these contract rights by removing the proposed changes to Section 95111(b)(1)(m)(3) and instead clarifying that the ARB will enforce the requirement to report REC serial numbers for specified imports. This

proposal will align the carbon obligation with the party that actually procured the environmental attributes.

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.<sup>1</sup> 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.<sup>2</sup>

TID is very concerned that this proposal will exacerbate the direct delivery requirement issues the ARB and reporting entities have faced with implementing the RPS adjustment requirements. Moving forward with the proposed amendments Section 95111(b)(1)(m)(3) will exacerbate these issues and devalue California's ratepayer's investments in out of state renewable resources in favor of other market participants. For these reasons, TID respectfully requests that the ARB retract the proposed revisions to Section 95111(b)(1)(m)(3) and enforce the REC serial reporting requirement in the current version of the MRR. At the very least, the ARB should continue to evaluate these proposed changes in conjunction with the proposals for addressing the RPS adjustment issues in the Cap-and-Trade Regulation.

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<sup>1</sup> See *C&A Carbone, 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).

<sup>2</sup> See *Pharmaceutical Research and Manufacturers of America v. Walsh et al*, 538 U.S. 644 (2003); See also, *Rocky Mt. Farmers Union v. Corey*, 730 F.3d 1070 (2013).

(TID1)

**Comment:** And the specified source import issue, it is more than just a clarification. It is a fundamental shift in policy. Right now, there is a requirement in the MRR for specified importers to report REC serial numbers. And that requirement has not been verified. And what these changes would do is they would remove that REC serial number reporting requirement. And they would basically allow an entity that has not purchased the green attributes from an out-of-state resource to claim the green attributes of that resource. That creates an inconsistency with the RPS program. And it undermines the value that California's ratepayers have paid for out-of-state RPS energy. So we would ask that, you know, you not just reconsider it and evaluate this in the context of the cap and trade, but really look at it in the context of its own issue under the MRR. (TID2)

**Comment:** REC Reporting Requirements. Due to RPS eligibility rules, certain California eligible renewable energy resources (ERRs) generate electricity that does not count toward California RPS compliance. For example, the portion of

incremental output counting toward California RPS eligibility may be determined using a methodology which considers a historical baseline and a renewable baseline.<sup>2</sup> The historical baseline is not counted as eligible under California's RPS, but RECs associated with the historical baseline generation are still created and may be considered eligible under another state's program. Although ARB's prior guidance has addressed REC reporting requirements for specified source imports from facilities that are California ERRs and, separately, from facilities that are not California ERRs,<sup>3</sup> it is not explicitly clear how RECs from specified source imports should be treated when the associated RECs, despite being produced by a California ERR, are ineligible under California's RPS. The lack of clarity on treatment of these RECs creates questions and concerns regarding the potential for (or at minimum, appearance of) double-counting of environmental attributes if California-ineligible RECs associated with a specified source import from an ERR are sold under a different state's renewable energy program.

To address this gap, we suggest that ARB require all RECs associated with specified source imports be retired and reportable (i.e., serial numbers) regardless of California RPS eligibility or RPS Adjustment claim. Doing so would provide the market with clarity it currently lacks and prevent any possibility of counting the same MWh of energy toward carbon goals in one jurisdiction and the RECs toward clean energy goals in another. Furthermore, we recommend that ARB work with the Western Energy Coordinating Council, more broadly, in order to expand the Western Renewable Energy Generation Information System (WREGIS) to track all sources of generation – renewable source or otherwise, generated or consumed in the state. This practice is currently used in New England through the New England Power Pool's Generation Information System (GIS), which issues and tracks certificates for all MWh of generation, imports and load associated with the ISO New England control area. Similarly, PJM relies upon the Generation Attribute Tracking System (GATS) to track all generation and load served in the PJM control area, and NYSERDA's New York Generation Attribute Tracking System (NYGATS) was recently developed to track all electricity generated in New York and imports consumed in the state. Each of these systems is designed to track the attributes associated with generation and consumption and to prevent the possibility that the generation attributes from the same MWh might be counted more than once by the applicable region or elsewhere. ARB should seek to promote the same result through WREGIS to avoid further confusion and inadvertent outcomes.

<sup>2</sup> See: California Energy Commission Renewables Portfolio Standard Eligibility Guidebook, issued June 2015: <http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf>

<sup>3</sup> See: ARB Electric Power Entity Reporting Requirements Frequently Asked Questions, Section 4: <https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/epe-faqs.pdf>

(BROOK1)

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

Section 95111 (a)(4): *Imported Electricity from Specified Facilities or Units.* The electric power entity must report all direct delivery of electricity as from a

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

- (A) Claims of specified sources of imported electricity, defined pursuant to section 95102(a), are calculated pursuant to section 95111(b), must meet the requirements in section 95111(g) and in section 95852(b)(3) of the cap-and-trade regulation, and must include the following information.

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

- (~~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 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 renewable energy resource then the electricity importer must have (1) a right of ownership or contract rights to the associated RECs; and (2) report the REC serial numbers associated with the imported electricity pursuant to section 95111(g)(2).

(56) *Substitute electricity*. Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section.  
(MID2)

**Response:** ARB did not propose to remove the requirement to report REC serial numbers associated with renewable electricity imports. The requirement to report REC serial numbers is still intact. Staff made changes to make clear that non-reporting of REC serial numbers results in a nonconformance with MRR. Several years ago ARB staff released public guidance documents that clarified that non-reporting of RECs results in a nonconformance with MRR. The inserted language in the 45-day modifications seeks to ensure the regulatory requirement is further clarified for reporters. This is also consistent with the intent of MRR as described on pages 108-111 of the MRR 2010 Final Statement of Reasons,<sup>10</sup> for the rulemaking in which the RPS adjustment was added to MRR and the Cap-and-Trade Regulations, and the implementation of the provisions.

The commenters suggest that ARB 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 of California. This is inconsistent with the intent of the RPS adjustment and the reasons for its inclusion per the 2010 MRR FSOR, in which ARB states that “RECs play no role in GHG accounting” and “the RPS adjustment applies to electricity that is not directly delivered to California, and therefore is not included in statewide GHG emissions accounting. The RPS adjustment is not a recognition of avoided emissions, but an adjustment to the compliance obligation to recognize the cost to comply with the RPS program” (page 108). The purpose of RPS program is to encourage development of eligible renewable energy; distinct from Cap-and-Trade Program’s role to provide cost-effective GHG emissions reductions. As further indicated in the 2010 MRR FSOR, “ARB does not believe that the purchase of RECs entitles the purchaser to any right to use those avoided emissions to comply with any GHG regulatory program, and that such a right is beyond the scope of the 45-day modifications” (page 110). For the comments relating to alignment of ARB’s programs with the RPS program, please see the responses to comments F-1 and F-13 in this section.

### **F-3. Multiple Comments: *MRR Requirements for Reporting RECs***

**Comment:** The MRR requires reporting information with respect to RECs, including REC serial numbers, by February 1<sup>st</sup>. However, this information is not fully available by February 1<sup>st</sup>, and in practice is normally provided with the later June 1<sup>st</sup> reporting. This could be solved by simply removing the REC requirement from the

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<sup>10</sup> <https://www.arb.ca.gov/regact/2010/ghg2010/mrrfsor.pdf>



existing regulation and placing it in more appropriate sections of the regulations, as follows:

*95111(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. Information related to the RPS adjustment is no longer required to be reported beginning with 2021 data reported in 2022.

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

(. . .)

~~(M) Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:~~

- ~~1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.~~
- ~~2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a~~

~~previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified, the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.~~

~~3. 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.~~

(4) *Additional Information for Specified Sources.* For each claim to a specified source of electricity, the electricity importer must indicate whether one or more of the following descriptions applies, and provide information as appropriate for the description:

(. . .)

(F) Deliveries from sources including Renewable Energy Credits (RECs): report the total number, vintage years and months, and serial numbers of all RECs, and whether or not the RECs have been placed in a retirement subaccount.

(5) Additional Information for RPS Adjustment Sources:

(A) RECs associated with electricity procured from 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.

(B) RECs associated with electricity procured from 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.

(C) ~~(5) Substitute electricity.~~ Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section.

(SMUD1)

**Comment:** 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.

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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 electricity imported 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.

(MID2)

**Response:** While ARB understands the recommendations, staff does not believe the changes are necessary at this time for effective implementation of the specified source and RPS adjustment requirements. Section 95111(g)(1) lists requirements for registration of specified sources and RPS adjustment claims. Electric power entities who seek to claim specified source electricity or an RPS adjustment must submit registration workbooks by February 1 following the data year for which those sources are reported, to allow staff to populate reporting workbooks and calculate emission factors for specified sources. ARB understands that some of the information may be unavailable by February 1, but asks electric power entities to continue to populate the registration workbook with the most accurate information available at the time. Section 95111(g) clarifies that the electric power entity

must report the full data as part of the emissions data report by June 1 and has an additional 45 days during the verification process to reconcile and finalize that information. The current location of these requirements and implementation of the reporting requirements has not resulted in any confusion among reporting entities on meeting these registration requirements.

#### **F-4. Multiple Comments: *Lesser of Analysis Exemptions in §95111(b)(2)(E)(1)***

The exemption from the "lesser of analysis" for grandfathered RPS contracts and dynamically tagged power deliveries should be retained [§95111(b)(2)(E)]. ARB is proposing the following amendments to the "lesser of analysis" requirement for specified imports of zero emission electricity:

**(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.

1) ~~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 399.16(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; (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, a lesser of analysis is required pursuant to the following equation:  

$$\text{Sum of Lesser of MWh} = \Sigma H M_{sp} \min(MG_{sp}, TG_{sp})$$
Where:  
 $\Sigma H M_{sp}$  = Sum of the Hourly Minimum of  $MG_{sp}$  and  $TG_{sp}$  (MWh).  
 $MG_{sp}$  = metered facility or unit net generation (MWh).  
 $S_{sp}$  = entity's share of metered output.  
 $TG_{sp}$  = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

2) An EPE may conduct the lesser of analysis voluntarily for those resources excluded in section 95111(b)(2)(E)(1.).

The proposed deletion of the exemption for grandfathered RPS contracts and dynamically tagged power deliveries is inconsistent with California's RPS regulations. Under the RPS regulations, the "lesser of" analysis applies only to Portfolio Content Category 1 renewable energy, which is electricity procured from an eligible renewable energy resource under a contract executed after June 2010 that is directly delivered from the generating facility to California, where the energy is not imported on a dynamic E-tag.

It may not be feasible to perform the "lesser of analysis" for grandfathered contracts and dynamically tagged power deliveries because the reporting entity may not have the contractual right to hourly meter data under legacy power purchase

agreements. The consequence of not being able to perform the "lesser of analysis" would be a non-conformance and a Qualified Positive verification statement. This result would be unfair to reporting entities whose report satisfies all the other rule requirements.

LADWP recommends that the "lesser of analysis" requirement should be limited to only electricity imported from Portfolio Content Category 1 renewable generating resources for which the "lesser of" analysis is required under the RPS regulations. Grandfathered contracts and dynamically tagged power deliveries should continue to be exempt from the "lesser of analysis". (LADWP1)

**Comment:** And lastly, the lesser of analysis is also a concern for us. Those -- the grandfathered RPS contracts were exempt for a reason. And it's because you don't have the contractual right to the meter data that you would need to do that lesser-of analysis. And so it's really unfair for staff to impose a requirement when you may not be able to have the data to be able to perform that requirement. And if you can't perform the requirement, then you get a non-conformance and a qualified positive verification statement. And so it's just -- the requirement should be feasible. And it's just not -- it's not a good idea to impose that on grandfathered RPS contracts. (LADWP2)

**Comment:** The MRR and Cap-and-Trade Programs Must Continue to be Aligned with the State's Renewable Portfolio Standard and Other Key Mandates and Programs.

Proposed changes to section 95111(b)(2)(E)(I) to eliminate the exclusion of "grandfathered contracts" from the lesser of analysis places an unnecessary burden on compliance entities. These provisions were originally intended to help align two of the state's premier carbon reduction programs- the Cap-and-Trade Program and the Renewable Portfolio Standard (RPS) Program. After several stakeholders expressed concerns when this language was added in the 2014 MRR revisions, ARB staff recommended the following: "to minimize additional reporting and verification burden, this requirement should be limited to only electricity imported from Portfolio Content Category 1 renewable generating resources for which the 'lesser of analysis is required under the RPS regulations.'"<sup>2</sup> M-S-R urges the Board to direct CARB staff to abandon the proposed revisions to eliminate the exclusion or to confer further with stakeholders on the implications, including the interaction between the proposed MRR changes and the proposed amendments to the Cap-and-Trade Program.

The Staff Report characterizes the changes as necessary "because the actual generated or metered amounts (MWh) of power generated from certain resources do not always match the tagged or the EIM model designated quantities, which have been reported as imported power." (Staff Report, p. 43) As CARB explicitly noted in the 2011, while renewable energy credit (RECs) "play no role in GHG accounting ...RPS electricity should reduce the compliance obligation of a first

deliverer."<sup>3</sup> Thus, provisions in the Cap-and-Trade Program were aligned with the MRR to ensure that this would occur. Changes to the MRR will directly impact the provisions of the Cap-and-Trade Program and entities' compliance obligations under that program.

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<sup>2</sup> 2014 MRR Amendments, Final Statement of Reasons, November 2014, p. 32.

<sup>3</sup> 2011 MRR Amendments, Final Statement of Reasons, October 28, 2011, p. 107.

(MSR1)

**Comment:** A Change That Needlessly Increases the Complexity of Reporting. The proposed change to 95111(b)(2)(E)(1) should not be adopted by the Board. Staff-proposed changes would eliminate certain exclusions to the "lesser of" analysis. This Staff-proposed change should be rejected for (1) grandfathered contracts that meet California RPS program requirements in Public Utilities Code Section 399.16(d) and (2) dynamically tagged power deliveries. Having these resources perform a "lesser of" analysis adds reporting complexity unnecessarily at a time when ARB is tightening reporting and verification deadlines. Secondly, it creates incompatibility with the RPS reporting requirements by potentially relying on less accurate E-tag information.

Dynamically tagged resources are outside the CAISO's balancing authority, but the resource is dispatched by the CAISO to meet CAISO load. The "lesser of" analysis is an hour by hour comparison of what was tagged compared to what was metered, but the meter data is the most accurate. As such, if meter data is used, it seems ineffective to have to compare it to the less accurate tagged amount. Tagging is a North American Electric Reliability Corporation (NERC) requirement when transferring power between balancing authorities that does not require the same degree of accuracy as the meter data, as acknowledged by ARB Staff.<sup>1</sup>

The same is true of grandfathered RPS contracts; the entire metered output is deemed delivered to California by the California Energy Commission, so the tags are less accurate and should not be used.

**SDG&E Recommendation:** The Board should continue the exemption to the "lesser of" analysis for both grandfathered RPS contracts and dynamically tagged resources in 95111(b)(2)(E)(1). ~~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 399.16(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;... (SDG&E proposed change is double underscored).

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<sup>1</sup> ARB Staff, Initial Statement of Reasons for MRR, page 44.

(SDGE1)

**Comment:** Changes to “Lesser Of” Analysis. SMUD does not support the significant removal of exclusions in the requirement to prepare a “lesser of” analysis for imported power. The MRR regulations have suggested for certain resources that an hourly comparison between metered and “scheduled” data must be made and the sum of the lesser of these hourly values be calculated for reporting purposes. In the Proposed Amendments, grandfathered RPS contracts and dynamically scheduled renewable imports have been removed from the list of exclusions. These contracts were excluded in order to conform to the “lesser of” analysis required for the RPS, and ARB should return to the full list of exclusions in the current regulations.

In addition, it is unclear from the language exactly how the proposed “lesser of” analysis should affect emission factors used in mandatory reporting. The implication and common practice, supported by guidance, is that the specified source emission factor would only be used for the generation that results from the “lesser of” calculation. However, this is not explicitly stated in the regulatory language nor is there clarity in the language about what emission factor should be used for any remaining generation that is scheduled into California above the result of the lesser-of analysis. It may seem reasonable to use the “unspecified” emission factor for this remaining generation, but this is not explicitly stated. In addition, the term “ $S_{sp}$ ”, which brings into the equation the entity’s share of output from the facility, is listed in the regulations as being in the lesser of equation, but it is not there. This confusion should be cleared up. (SMUD1)

**Comment:** Secondly, another concern that we have is the expansion of the lesser-of analysis to contracts that are currently grandfathered under the RPS. In the RPS program, a lesser-of analysis is required for some contracts the MRR as it stood last year before the proposed amendments was consistent with that. The expansion makes it inconsistent with that. And it's our position that you should have more consistency with the RPS and not less. It's going to be inefficient to require entities to do a particular kind of analysis under one program, and not have it under another program. (SMUD2)

**Comment:** I'll -- another echo, is about the lesser-than analysis, and implications on the RPS adjustment, the RPS Program and how it's disjointed. And we really need to have things be more congruent with all policies in California. (SVP1)

**Comment:** The second concern regards the ‘lesser-of’ analysis in section 95111(b)(2)(e). CARB staff have proposed elimination of the lesser of analysis requirement for electricity imported via the EIM. We understand that this is due to staff’s understanding that the EIM export allocation is not adjusted to reflect actual metered data, but instead reflects the resource’s forecast availability going into the hour. Rather than require the ‘lesser-of’ analysis for zero-emission EIM participating resources, WPTF suggests that CARB explore whether it would be possible for the EIM export allocations to more accurately reflect metered generation for these resources.

Similarly, in section 95111(b)(2)(E)(2), staff have added language to enable an EPE to voluntarily conduct the lesser of analysis for resources excluded from mandatory lesser-of analysis section 95111(b)(2)(E)(1). It is not clear why an EPE would conduct this analysis, if not required by the regulation. WPTF requests that CARB staff to explain why this provision has been added. (WPTF1)

**Response:** In light of stakeholder comments and upon further analysis, ARB modified MRR in the 2<sup>nd</sup> 15-day package to maintain the lesser of analysis exemptions for grandfathered RPS contracts and dynamically tagged power deliveries. Staff will continue to evaluate the ability of dynamically tagged imports to minimize differences between tagged and metered quantities. The exemption for EIM was not retained because each participating resource scheduling coordinator will have access to the meter data through its affiliation with the generation source. Finally, WPTF asked ARB to explain why an EPE would voluntarily conduct the lesser of analysis for resources excluded from section 95111(b)(2)(E)(1). To respond, EPEs have requested permission to conduct this analysis as part of their annual emissions data reports, in order to increase the accuracy of their reported emissions. Staff believes this was a reasonable request, and has proposed a regulatory revision to offer that flexibility.

#### **F-5. Comment: *Documentation for Short-Term Specified Source Transactions***

Documentation for Short-Term Specified Source Transactions. Per Section 95102(a)(358) of the MRR, “a power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier’s system that is designated at the time the transaction is executed.” The phrase “designated at the time the transaction is executed” thus requires documented proof of intent on behalf of both the buyer and seller of specified source power, which shows that at the time the transaction was finalized each entity clearly agreed to transact specified source power. Brookfield does not take issue with the current requirement that a showing of intent be made on behalf of both the buyer and seller. Furthermore, we commend ARB on the prior work done to allow for the transacting of specified source power on a short-term basis. However, Brookfield believes ARB Staff’s interpretation and administration of the current MRR language regarding proof of intent is overly narrow, thereby creating unnecessary restrictions to the ability for all market participants to transact for short-term specified source power.

Current ARB guidance, found in Section 1.3.3 of the April 2016 version of ARBs *Electric Power Entity Reporting Requirements Frequently Asked Questions (FAQs) for California’s Mandatory Greenhouse Gas Reporting Regulation*, states the following:

*Short-term power transactions can be verbally transacted via phone.  
Although an entire short-term transaction can be accomplished via voice*



*record, both buyer and seller may have very different opinions about what product was actually transacted, e.g., whether specified or unspecified power was transacted. Thus, not all short-term transactions may result in an explicit acknowledgement between buyer and seller of the type of power transacted. In this scenario, an EPE may use the voice tape to indicate that the buyer agreed to a specified source product prior to execution of the transaction, and thereby establish evidence of seller warranty, which can then be used as evidence during the verification process.*

Per the guidance language, ARB requires voice recording to support the intent of the buyer and seller at the time a transaction occurs. While additional documentation may be provided to support the claim, a voice recording tied to the transaction will always be necessary to establish evidence that the buyer and seller agreed to transact specified source power where trade-specific written confirmations are not used. The problem at hand is a simple: i) negotiations with other market participants have revealed an unwillingness to engage in daily written confirmations and ii) not all entities enlist the use of recorded phone lines to engage in trading activities. Instead, some entities utilize email to finalize the intent of a transaction, while others may use instant messaging or some other function to agree to terms, in addition to formal written confirmations between the transacting parties (though rarely daily written confirmations). Thus, by requiring that recorded lines be used to support all short-term specified source claims ARB has restricted some market participants from engaging in the sale or purchase of this market product – despite other available means of supporting the intent at the time of a transaction.

Brookfield urges ARB to consider alternatives to the current implementation of Section 95102(a)(358) of the MRR, by first considering the preferred confirmation practices when contemplating any changes to documentation requirements.<sup>1</sup> Furthermore, ARB should consider enabling – without voice recording – the usage of time-stamped email, archived print screens of an instant messaging conversation or instant messaging logs to serve as main support for a short-term specified source claim. If necessary, formal written confirmations like those described above could be used as supporting documentation to the time-stamped email or instant messaging record. Brookfield has been unable to determine why, in particular, providing time-stamped email exchanges, archived print screens of instant messaging conversations between counterparties or instant messaging logs, that explicitly state the terms of a short-term transaction – including acknowledgment of the transaction as the sale and purchase of specified source power, would fail to meet the requirement that intent be shown at the time the transaction occurred. Furthermore, we do not believe such changes would be at odds with the intent of AB 32 or the goals of the Cap and Trade Program. Importantly, because the requirement for voice record is not explicit in the MRR, we believe such a change requires only a revision to the ARB's guidance document.

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<sup>1</sup> Discussions have indicated a preference for weekly and monthly confirms that consists of either the WSPP attachment C-SS with all the specified source trades agreed to for a given week or month included or a custom confirm for specified source, which includes the seller warranty with all the specified source trades agreed to for a given week or month.

(BROOK1)

**Response:** This comment is out of scope for this rulemaking as staff did not propose modifications to these sections of the Regulation. ARB does not believe that any additional clarifications are required. ARB's Electric Power Entity Reporting Requirements Frequently Asked Questions (FAQs)<sup>11</sup> seeks to clarify situations in which a record, including voice records, may be needed to confirm the power product transacted. However, the guidance also acknowledges that under standard enabling agreements, verbal can mean both verbal and electronic (Instant Messenger). Any use of those types of records, which confirm unambiguously the type of power transacted, and which can be provided to the satisfaction of the verifier, are acceptable.

#### **F-6. Multiple Comments: *First Point of Receipt (POR) and Source of Generation***

**Comment:** Section 95111(a)(2) General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters; Delivered Electricity. The proposed amendment would require reporters to include the 'generation source' when known, rather than the first point of receipt (POR). This information, documented on E-tags, is often unclear since the acronyms or partial names used do not provide clarity regarding whether the source is a generating facility or a trading hub. Since this information is used to report unspecified electricity, we propose that ARB require only reporting of the POR since the 'generation source' does not impact a reporter's resulting GHG obligation. (PGE1)

**Comment:** Staff have modified section 95111(a)(2) to require reporting of delivered electricity by generation source when known, as well as by point of receipt as currently required. Given that electric power entities are already required to also report imported electricity separately by specified and unspecified sources, we do not understand the intent of this addition. WPTF requests CARB to clarify the meaning of the new language. (WPTF1)

**Response:** In the 45-day amendments, staff clarified the definition of "first point of receipt" as used in MRR, and that imported power must be disaggregated by generation source. However, in the first 15-day modifications issued on December 21, 2016, staff withdrew the proposed amendment, which addressed the concerns of commenters.

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<sup>11</sup> Electric Power Entity Reporting Requirements Frequently Asked Questions (FAQs), <https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/epe-faqs.pdf>

#### **F-7. Comment: Sales into CAISO under Section 95111(a)(12)**

Sales into the CAISO. SMUD supports additional clarification of the requirements for reporting sales into the CAISO. The Proposed Amendments include a new provision that entities must report sales into the CAISO that do not serve “native load”. SMUD simply notes that subpart (B) still states that “This requirement does not apply to EDUs that have had all of their directly allocated allowances allocated for the data year placed in their limited use holding account pursuant to section 95892(b)(2) of the Cap-and Trade Regulation.” This statement is ambiguous, as it is unclear whether it applies only to the subpart (A) that is in the current regulations, or to the new subparts (C)-(E), or to all of the subparts in the section.

There is still a blanket prohibition on using allowances and allowance value for sales into the CAISO in the Cap and Trade Regulations, and the exemption in subpart (B) appears to be in conflict with that requirement, which could cause confusion amongst the EDUs as to exactly how any sales into the CAISO are to be handled and reported. (SMUD1)

**Response:** In the 45-day amendments, staff proposed several clarifying modifications to the CAISO sales requirements in section 95111(a)(12) and its proposed subparts, and the proposed changes to 95111(a)(12) remained unchanged in both the first and second 15-day issuances. First, SMUD states that subpart (B) in section 95111(a)(12) is ambiguous because it is unclear whether it applies only to subpart (A) that is in the current Regulation, or to the new subparts (C)-(E), or to all of the subparts in the section. ARB has already clarified in its guidance document Electric Power Entity Reporting Requirements Frequently Asked Questions (FAQs),<sup>12</sup> that subpart (B) applies to the entire section 95111(a)(12). Non-IOU EDUs that are allocated any number of allowances are subject to the provisions of section 95111(a)(12). Section 95111(a)(12)(B) clarifies that if an EDU has had all of their directly allocated allowances allocated for the data year placed in their limited use holding account pursuant to section 95892(b)(2) of the Cap-and-Trade Regulation, they are not subject to the remaining requirements of section 95111(a)(12). Additionally, ARB notes that there is substantial guidance on how to report sales into CAISO markets in the FAQ document referenced above.

In addition, ARB staff notes that the Cap-and-Trade Regulation is clear on the prohibition of the use of *any* allocated allowance value (whether it be the use of allowances directly *or* the auction of allocated allowances and use of allocated allowance auction proceeds) to cover the compliance obligation associated with electricity sold into CAISO markets. The reporting required by MRR about the use of allowances directly for compliance should not be interpreted to mean that the auction proceeds from the sale of allocated allowances can be used to purchase allowances to cover the compliance

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<sup>12</sup> <https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/epe-faqs.pdf>

obligation of electricity sold into CAISO markets, as that is prohibited via the Cap-and-Trade Regulation.

#### **F-8. Comment: Service of Non-California Load through CAISO**

VEA is a small electric cooperative utility, primarily serving load in Nevada. VEA, recognizing the benefit of regional cooperation, was a first-mover in transitioning the service of its Nevada load into the CAISO as a Participating Transmission Owner (PTO) and a CAISO Load Serving Entity (LSE) in 2013. Through the CAISO, VEA serves on average 60 MW/hour of load spread through southern Nevada. VEA services its load through federal river project hydroelectricity, pooled supply agreements with other cooperatives, and economy energy purchases outside of California. Since 2013, VEA has served its Nevada load through CAISO imports at Mead - a delivery point located outside of California. VEA works diligently to balance its electricity supplies to its load. On an annual basis, VEA's imbalances which now flow through the CAISO's markets, have been a small fraction of VEA's total Nevada load.<sup>1</sup>

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 CARB carbon costs being imposed on non-California load being served through the CAISO.

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<sup>1</sup> For example, on net VEA had approximately 1% imbalances for its Nevada load served through the CAISO in 2015.

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.<sup>2</sup> 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.<sup>3</sup>

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.<sup>4</sup>

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<sup>2</sup> Regional Integration California Greenhouse Gas Compliance issue paper, CAISO, August 29, 2016 (<http://www.caiso.com/Documents/IssuePaper-RegionalIntegrationCaliforniaGreenHouseGasCompliance.pdf>), p. 3).

<sup>3</sup> *Id.*, FN 9.

<sup>4</sup> *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.<sup>5</sup>

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<sup>5</sup> 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.

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-a-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 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.<sup>6</sup> 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 load<sup>7</sup> through the CAISO even though CARB policies call for such allocations.<sup>8</sup>

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.



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<sup>6</sup> 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.

<sup>7</sup> 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.

<sup>8</sup> 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...”.

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.<sup>9</sup>

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<sup>9</sup> 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.

<sup>10</sup> 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.

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.<sup>10</sup> 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 provision s 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 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. (VEA1)

**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. As shown below, ARB did not make the specific modifications proposed by Valley but instead made other modifications to the regulation to clearly distinguish between electricity serving load in California and electricity scheduled through CAISO to serve load outside of California.

***Excerpt from October 2011 C&T Final Statement of Reasons <sup>13</sup>***

***I-40. Comment:*** *Valley Electric requests that CARB explicitly recognize the intent to distinguish between load that sinks in the state of California versus that which does not by indicating that further information may be necessary.[excerpt of full comment]*

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<sup>13</sup> Page 1464, California's Cap-and-Trade Program, Final statement of Reasons, October 2011. <https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf>



***Response:*** Although we did not make the specific modifications that Valley Electric suggests, we worked with Valley Electric and made other modifications to the two definitions in order to clearly distinguish between electricity serving load in California and electricity that Valley Electricity schedules into the CAISO market but uses to serve load outside of California. Valley Electric.

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.

Regarding the changes to section 95111(a)(12)(D), that section of the regulation does not include requirements for reporting emissions from imported electricity, so the amendments proposed would be misplaced. The requirements in section 95111(a)(12)(D) only address how to report sales into CAISO with respect to electrical distribution utility use of allocated allowance value.

#### **F-9. Comment: *GHG Reductions Outside California***

GHG Reductions Outside California Should Be Recognized. The cap-and-trade program includes GHG reductions outside of California to count as reductions for purposes of the cap-and-trade program. However, these reductions are not considered in the GHG Inventory. As the Board considers regulations that extend GHG reductions beyond 2020, the Board should give California entities the benefit of the GHG reductions paid for by California entities. The Board should specifically include an adjustment to the calculated GHG inventory for GHG reductions occurring through out-of-state offsets and the RPS adjustment. Since GHG is global, for purposes of the MRR and GHG inventory, these reductions should offset some California emissions in the GHG inventory used to measure progress toward the State's 2030 GHG reduction goals. (SDGE1)

**Response:** This comment is out of scope for this MRR rulemaking because it was not incorporated in the proposed revisions or included in the notice of changes.

#### **F-10. Multiple Comments: *Accounting For Imported Electricity Emissions from EIM and Addressing Emissions Leakage***

The comments in this section address several issues related to the CAISO's EIM market. While the comments are lengthy, they deal with a specific set of issues that staff addresses in its response. Specifically, the comments in this section discuss issues related to how CAISO's EIM deeming methodology determines which

resources to attribute as having served California load, and therefore, how emissions are reported and assigned a compliance obligation under ARB's Mandatory Reporting and Cap-and-Trade Regulations. The comments also address GHG emissions leakage that occurs because of the deeming methodology currently in place under EIM. In addition, the commenters offer several alternatives to how the EIM model could be changed to account for emissions leakage. While ARB has identified issues with the deeming methodology and sought to address accounting issues through the bridging solution introduced in the first 15-day amendment package, changes to the EIM model are outside the purview of ARB, as that model is designed and implemented by the CAISO. CAISO is currently working to address the accounting issues inherent to the current deeming methodology.

Stakeholders have also identified issues related to how ARB should account for underreported emissions under EIM, specifically whether ARB should use the default emission factor in the current Regulation to quantify the missing emissions and how to account for imports and exports of electricity occurring under EIM. ARB has addressed these comments in the response referenced above.

**Comment:** WPTF agrees with the concerns raised by CARB staff that the EIM algorithm is distorting dispatch in some cases resulting in increased emissions in the combined CAISO/EIM footprint. However, rather than address this through CARB's administrative assignment of additional carbon costs to California EIM purchases, WPTF recommends that CAISO initiate a stakeholder process to consider modifications to how the EIM algorithm treats carbon costs in the dispatch and attribution of generation to serve CAISO load. For this reason, we oppose CARB's proposed addition of paragraph 95111 (h) "Reporting requirements for the California Independent System Operator."

WPTF recommends that CAISO stakeholder process on EIM GHG accounting also address two other issues. First, WPTF is concerned that the current reporting regulation provides the possibility that imported electricity from an external resource that participates in the CAISO markets and the EIM could be double-counted. This would occur if the resource scheduled a delivery into California as a result of a bid in the CAISO markets, then was dispatched in the EIM by an amount that included the quantity already scheduled. Because the electric power entity is required to report both the scheduled delivery and the EIM export allocation to CARB, this could double-count the quantity of imported power. CAISO staff indicate that this situation could be avoided by the resource not submitting an energy bid in the EIM for dispatch to CAISO load. We do not consider this sufficient, since the entity may not be aware of the potential for double-counting. Instead, we recommend that the CAISO develop procedures to ensure that the EIM algorithm does not assign an export allocation to electricity that was previously scheduled as an import in the CAISO markets.

\* \* \*

Calculation of the quantity of electricity delivered to California via the CAISO markets. As WPTF explains in our comments on the proposed changes to the cap and trade regulation, the cap and trade and MRR do not currently treat the flow of electricity through California consistently across the EIM and other CAISO markets. This inconsistent treatment, which will be further exacerbated by the elimination of the qualified export adjustment, does not accurately account for electricity that serves California load and may disincent participation in the CAISO markets.

To align the GHG accounting of power flows across the EIM and CAISO markets, and more accurately reflect state electricity consumption, WPTF recommends that CARB modify the MRR to account for the quantity of power consumed in the state on a *net-interchange* basis for all CAISO markets:

- CARB should request CAISO to calculate the ratio of net imports to final scheduled imports, exclusive of EIM, for each hour<sup>1</sup> and provide this information to scheduling coordinators and to CARB.
- Section 95111(a)) should be modified to allow electric power entities to reduce the quantity of scheduled (e-tagged) imports for each hour by the ratio of net/scheduled imports provided by the CAISO for that hour.

This approach avoids the need to net electricity exports against particular imports or to net emissions, and instead simply corrects the quantity of imported power. If discussions regarding GHG accounting in the EIM and regional ISO result in changes to how import flows are assigned to specific resources, then such an approach could also be considered for netting of exports in the CAISO markets.

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<sup>1</sup> Quantification of this ratio could be done on a more granular basis if desired. We believe that an hourly basis would provide for sufficient accuracy and conform with CARB's current practice for reporting of schedules on an hourly basis.

(WPTF1)

**Comment:** SDG&E has recommended that the Board reject Staff-proposed changes to address secondary emission effects or “remaining emissions” impacts of the EIM since ARB regulations and California Independent System Operator (CAISO) optimization determine which power is deemed imported to California, so this issue is already covered sufficiently.

**SDG&E Recommendation:** Consistent with that recommendation, SDG&E requests the Board reject the proposed changes to the MRR regarding EIM:

- The definition of “Electricity Importers” should not be changed to include the EIM purchaser in section 95102.
- The definition of “Imported Electricity” in section 95102 should not be changed to include “electricity emissions not reported by EIM Participating Resource Scheduling Coordinators but distributed to EIM Purchasers pursuant to section 95852.”
- Section 95111(h) regarding “remaining emissions,” electricity emissions not reported by EIM Participating Resource Scheduling Coordinators but distributed

to EIM Purchasers, should not be added. Not only is it inconsistent with the treatment of bilateral contracts with those same sources, it cannot be accurately measured. The Staff analysis shows that there are large discrepancies between actual meter output and CAISO model results. (SDGE1)

**Comment:** Section 1. 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.<sup>5</sup> 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.

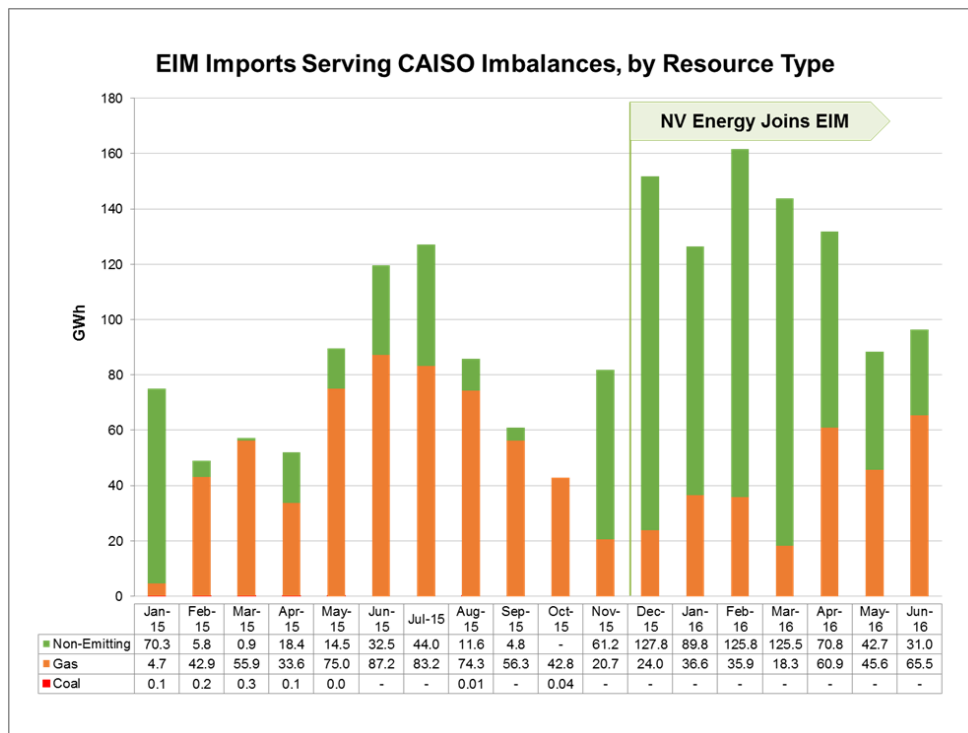
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<sup>5</sup> Hogan, W. W. (2013). CAISO Energy Imbalance Market Straw Proposal: Comments (pp. 1–4). Available at [http://www.hks.harvard.edu/fs/whogan/Hogan\\_CAISO\\_EIM\\_Notes\\_062613.pdf](http://www.hks.harvard.edu/fs/whogan/Hogan_CAISO_EIM_Notes_062613.pdf)

The three figures below illustrate the need for a more thorough understanding and review of GHG treatment in the EIM.

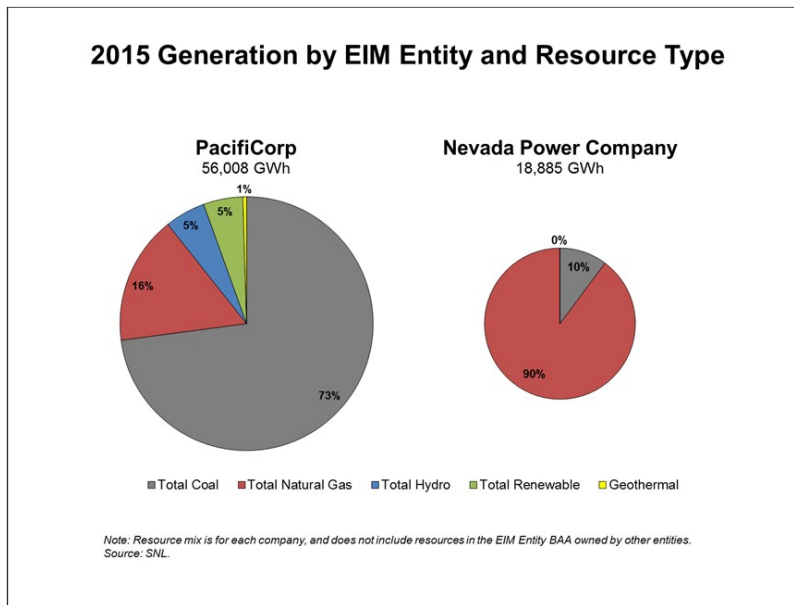
The first useful metric for assessing GHG treatment in the EIM is the CAISO's reporting of EIM transfers to serve CAISO imbalances, which CAISO allocates among (1) coal resources; (2) natural gas generation; or (3) non-emitting resources. This is shown in the chart below, and appears to report that approximately 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.

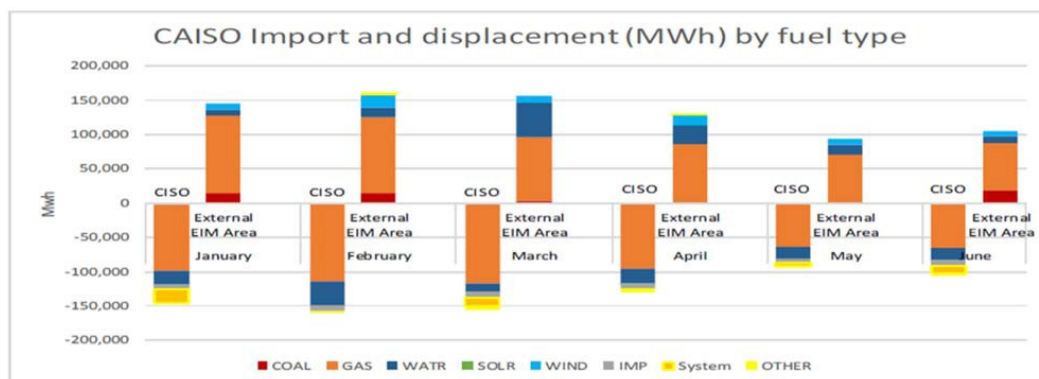


Source: Plotted from CAISO *MonthlyEIM\_Transfer\_ISO\_Imbalances\_MWh.xlsx*.  
 Available at: <http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>

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 non-emitting resources.



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.”<sup>6</sup> 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 *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.

<sup>6</sup> CAISO *EIM Greenhouse Gas Counter-Factual Comparison-Preliminary Results\_Jan-Jun\_2016\_.pdf*, at 2.

<sup>7</sup> 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.

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.<sup>7</sup> 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 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 non-emitting



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 resource-specific GHG intensity or at the unspecified GHG intensity.<sup>8</sup>
- 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.

<sup>8</sup> 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.

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 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.”<sup>9</sup> 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.<sup>10</sup>

<sup>9</sup> CAISO *Regional Integration California Greenhouse Gas Compliance Issue Paper* (August 29, 2016) at 8. Available at <http://www.caiso.com/Documents/IssuePaper-RegionalIntegrationCaliforniaGreenHouseGasCompliance.pdf>

<sup>10</sup> 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.

*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 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.<sup>11</sup> 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).

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<sup>11</sup> CAISO EIM Draft Final Proposal (September 23, 2013) at 90-95. Available at <http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf>

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.*<sup>12</sup> 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.

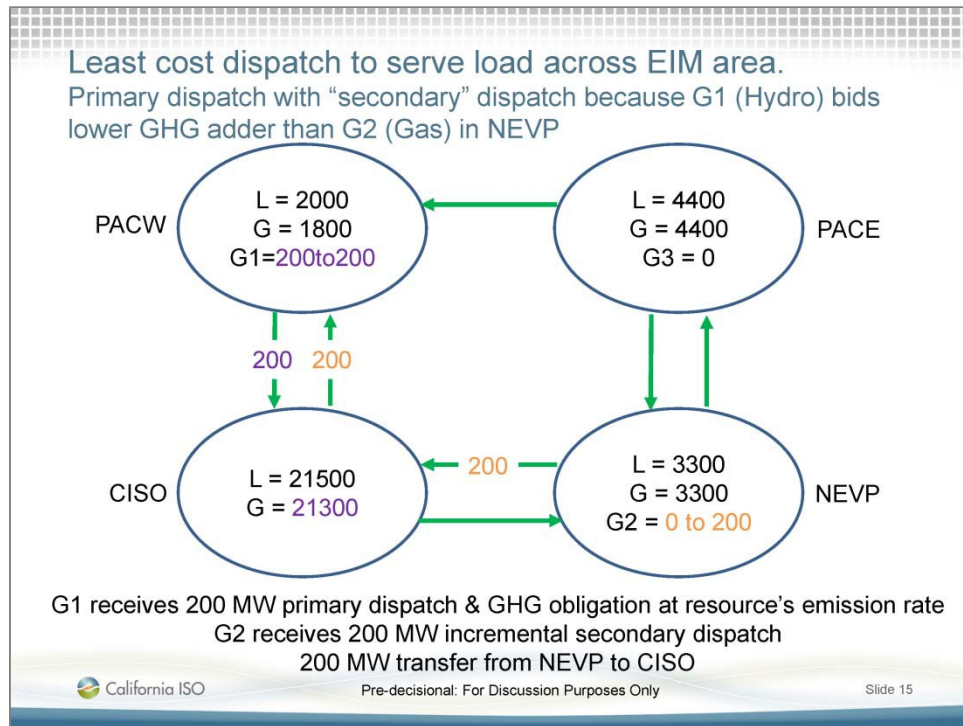
<sup>12</sup> See, e.g., CAISO EIM Draft Final Proposal at 84 ("Thus, ***only the imbalance energy*** portion that is imported into the ISO would be subject to a GHG compliance obligation." Emphasis added) and CAISO stakeholder meeting presentation at slides 39-40 ("EIM dispatch algorithm will include ***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-EnergyImbalanceMarket-DraftFinalProposal.pdf>.

#### 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.

The potential for such an outcome to occur was recognized and explained in CAISO's June 24 presentation using the example reproduced below.<sup>13</sup> 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 Powerex's view, this is contrary to CARB's GHG Regulations that seek to prevent carbon "leakage,"<sup>14</sup> 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.<sup>15</sup> 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).
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.<sup>16</sup>

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 e- Tagged 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-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.<sup>17</sup> 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 equal the application of the “unspecified source” GHG rate to EIM imports serving load in California.<sup>18</sup>

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.”<sup>19</sup> 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, 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.

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## Section 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

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.<sup>24</sup> 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.<sup>25</sup>
- 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 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.<sup>26</sup> 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 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.<sup>27</sup>

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?

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 re- arranging 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 responsibility to the wrong resource?	YES	YES	Assignment is at the unspecified rate	NO	NO
Potential for Double-counting 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

Section 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. 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 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

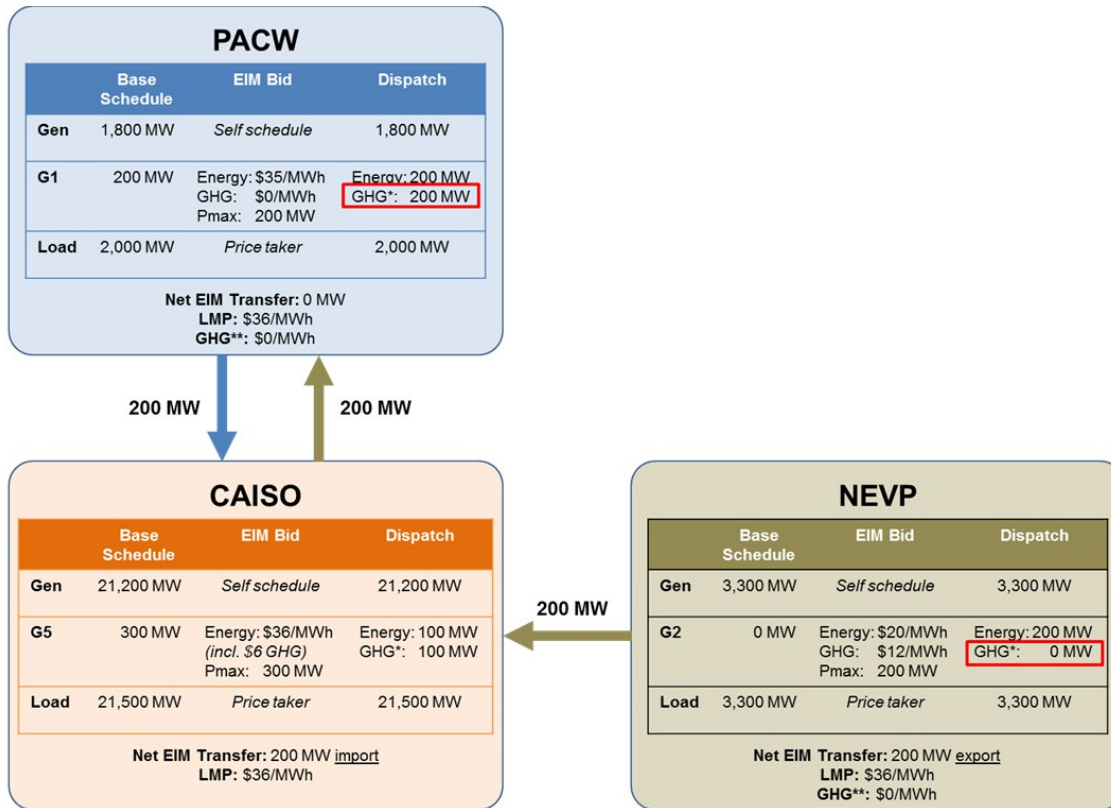


applying them in the EIM. Among other reasons, the EIM applies to a relatively small portion of resource production, serving to *augment* the bilateral transactions with a platform for intra-hour transactions. The EIM must therefore co-exist with a large quantity of transactions and delivery commitments 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).

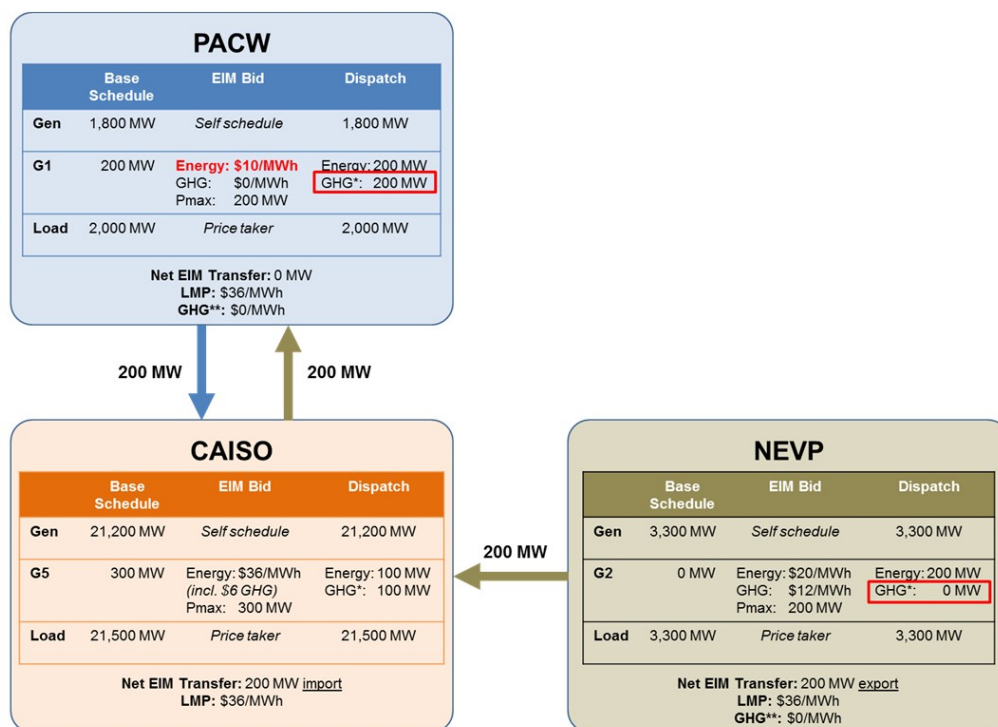
Powerex believes that such a precise alignment of resource offers is likely to be relatively uncommon in the EIM. In particular, many zero-GHG resources like wind, solar, or run-of-river hydro will tend to have relatively low variable costs, making criterion 2, above, less plausible.

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.<sup>28</sup>



\* 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. 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.<sup>29</sup>

<sup>28</sup> 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 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 MW \* (\$12/MWh) = \$2,400 over the solution shown in the graphic. 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.

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.<sup>30</sup> 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 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.

<sup>29</sup> 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  $P_{max}$ ) 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.

<sup>30</sup> 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.

### Scenario 3: Example of EIM Algorithm causing "leakage" by dispatching the wrong resource

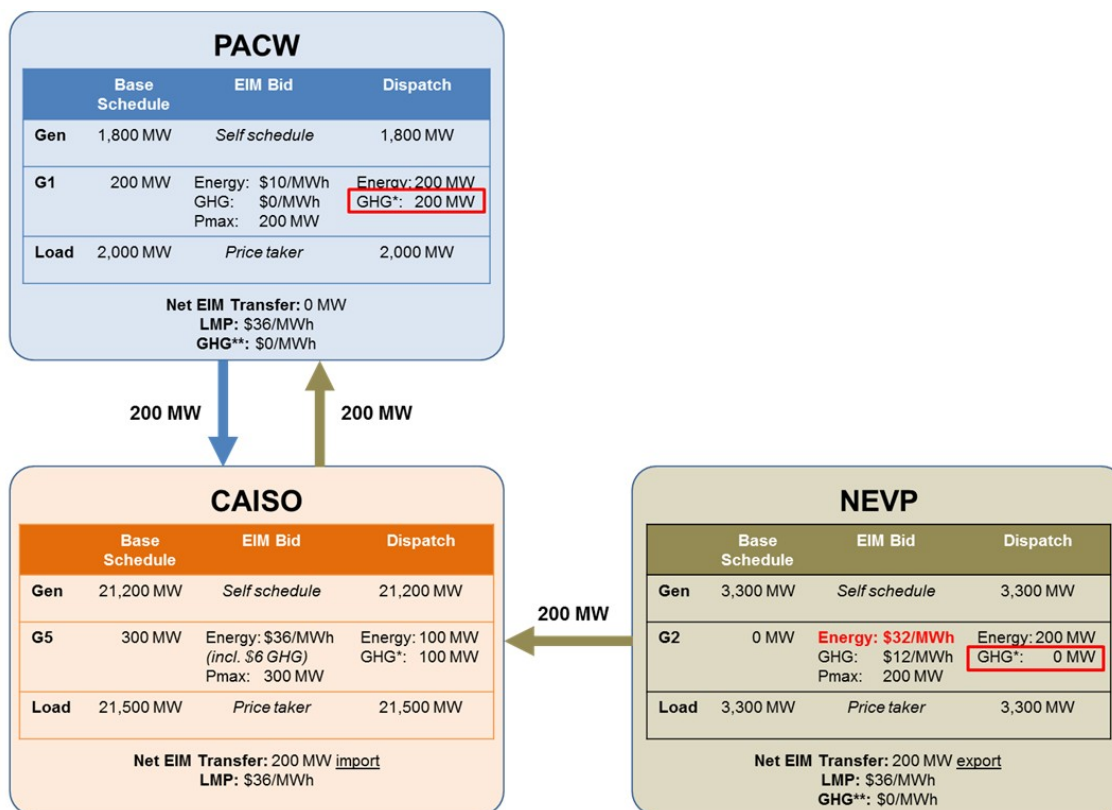
This scenario is identical to Scenario 2, except that the energy bid price of NEVP G2 is increased to \$32/MWh (compared to \$20/MWh in Scenario 2). This means that the combined cost of energy and GHG emissions from NEVP G2 is now \$44/MWh, which is higher than the combined cost of energy and GHG emissions 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.<sup>31</sup>

<sup>31</sup> 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  $200 \text{ MW} * (\$36 - \$32) = \$800$ . 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  $200 \text{ MW} * (\$12/\text{MWh}) = \$2,400$  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.

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 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.

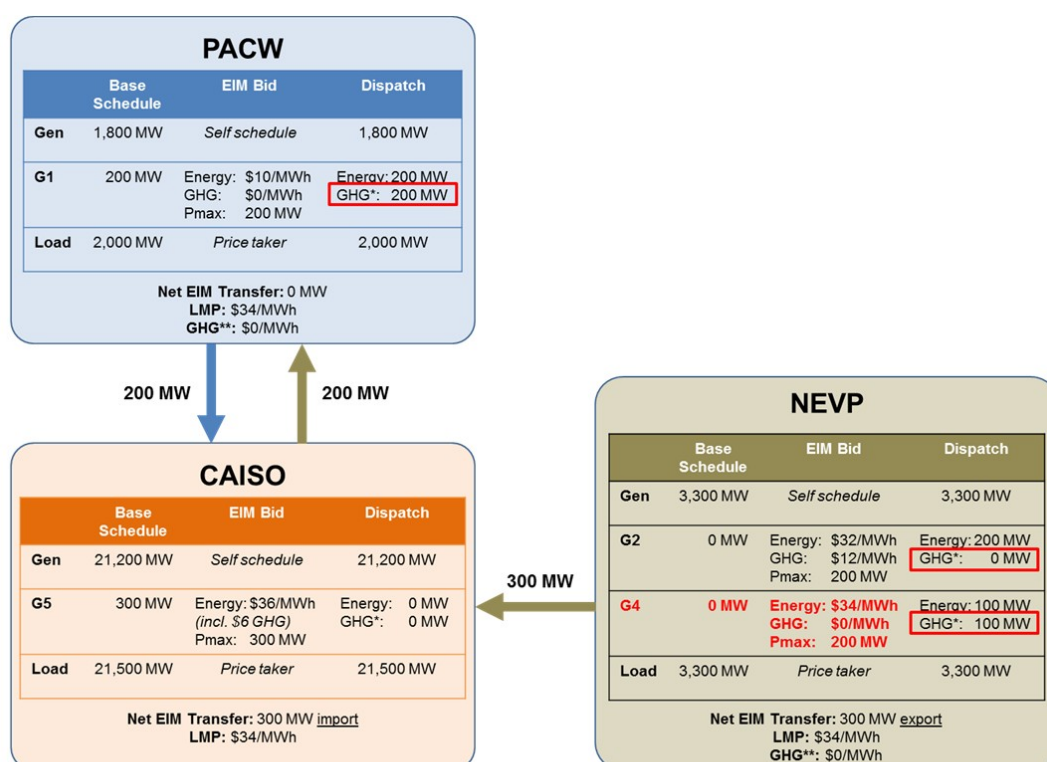
The following scenario shows that “leakage” and the favorable opportunities for high-GHG resources can occur even when lower-GHG out-of-state resources are available, and when “leakage” could be avoided.

#### 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.<sup>32</sup>

<sup>32</sup> 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 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. (PWX1)

**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:

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<sup>17</sup> ARB Staff Report, p. 51.

[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 CO<sub>2</sub>e 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.”<sup>18</sup>

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<sup>18</sup> ARB Staff Report, p. 52.

(ORA1)

**Comment:** These comments address CARB's proposed amendments to the GHG reporting requirements in the energy imbalance market ("EIM"). As staff noted, the current tracking and reporting of GHG emissions in the EIM does not ensure a full accounting of GHG emissions associated with electricity generated to serve California load. Resolving this issue with respect to the EIM is critical to ensuring the integrity of California's carbon trading system. Potential solutions also have implications for the proposed day-ahead energy market, and therefore Sierra Club is also providing these comments to CAISO to address the issue of how to ensure that compliance with California's laws and regulations is maintained in a proposed regional day-ahead energy market.

Sierra Club recognizes the potential environmental value of better coordination through a regional system operator ("RSO") in the West. As Sierra Club has stated in past comments, a properly constructed regional energy market may reduce curtailment of California's renewable resources, accelerate the development of additional renewable generation, decrease regional GHG emissions, and allow a more efficient commitment of energy resources in California and throughout the region. Some of these benefits appear to be occurring right now within the EIM. According to a counter-factual analysis provided by CAISO, the net GHG impact of the EIM is a reduction in regional GHG emissions.<sup>3</sup>

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<sup>3</sup> [http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults\\_Jan-Jun\\_2016\\_.pdf](http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_Jan-Jun_2016_.pdf)

While the observed decline in net GHG emissions in the West is a positive development, it is important to understand that those beneficial reductions are the result of clean California exports displacing dirtier out-of-state generation, both from coal and natural gas. However, imports into California are having the reverse effect: the EIM is creating a net increase in GHG emissions due to an increase in coal and natural gas generation during periods of import. Understanding this dynamic during the periods when California is importing power from the EIM is critically important to maintaining the integrity of California's GHG regulations and to ensuring that any potential day-ahead energy market properly accounts for and regulates GHG emissions that are caused by California electricity consumption. It is also crucial for ensuring that the price signals in the EIM market accurately reflect the emissions characteristics of the resources actually serving that market, so that price signals associated with California's clean air rules actually support cleaner sources of generation as intended.

I. Leakage Is Occurring Through The EIM. CAISO's analysis of GHG emissions in the EIM suggests that there is a net climate benefit from the market due to California exports displacing out of state fossil generation. However, from a policy standpoint, the EIM's impact on GHG emissions must be considered in two parts: (1) during periods of export from California, and (2) during periods of import into

California. Under the first condition, during periods of export, CARB appears to be properly accounting for the energy generated within the system because those resources are either non-emitting, such as California solar, or their GHG emissions have already been identified and incorporated into their cost of production as in-state generation with a compliance obligation.

In contrast, during periods of import, there is a distortion in the market occurring due to the failure of the EIM's GHG bid adder regulation. The GHG adder in the EIM was conceived to provide a mechanism that would allow California to identify out-of-state sources of GHG emissions that are attributable to California consumption, and to require those sources to obtain carbon allowances. However, determining when an out-of-state resource provides energy to California in the multi-state market is complicated; when CAISO directs a resource to provide or withhold imbalance energy, there is no clear path between the resource providing the energy and the load served. The GHG adder mechanism attempted to address this problem by allowing "bid adders" for out-of-state resources that *might* be subject to GHG charges if their energy is sold into the California market. If the energy is "deemed" to be sold into California, the energy is dispatched at a higher price that covers the bid adders and the sellers' GHG compliance obligation. If it is "deemed" to be for out-of-state use, it is dispatched without consideration of the bid adder.

This process of "deeming" energy flows is severely flawed because it is divorced from the actual energy production and emissions to the atmosphere that are due to redispatch through the EIM. CAISO and CARB conducted a workshop on June 24, 2016 to address significant shortcoming in the GHG adder mechanism. CARB raised the concern that, "EIM optimization results may not in all cases report full GHG burden experienced by the atmosphere as a consequence of electricity consumed in CA."<sup>4</sup> CAISO further explained how the mechanism may be failing: "Least cost dispatch can have effect [sic] of sending low emitting resources to CAISO, while not accounting for secondary dispatch of other resource [sic] to serve external demand."<sup>5</sup> In fact, while the ISO's counter-factual analysis shows that the vast majority of redispatch to meet EIM imports in the period January-June 2016 came from gas-fired generation, the EIM MWh imported into California during the same period were about 65% "deemed" to come from non-emitting resources.<sup>6</sup>

This type of resource shuffling<sup>7</sup> could similarly undermine the effect of state environmental policies in a regional market. For example, coal plants may dispatch more frequently within the region as a result of the opportunity to serve California load, but may avoid compliance with California's GHG rules by replacing low emitting resources that are nominally redirected to serve California load. California would be "served" by the low-emitting resources, but the increased emissions to the atmosphere would reflect a physical increase in fossil unit dispatch.

The failure of the GHG adder mechanism in the EIM is concerning. Even though the overall effect of imports and exports in the EIM appears at this time to be a net reduction in GHGs, California's GHG regulations do not, and should not, consider such

system-wide netting effects in its carbon allowance market. To the contrary, AB 32 expressly directs CARB to minimize “leakage,” which is precisely what is occurring in the EIM during periods of import.<sup>8</sup> This leakage means that California ratepayers are inadvertently and perversely supporting higher-emitting resources through the state’s clean-air rules. The problem of leakage is likely to grow as the EIM expands, and it could become a much larger problem in a full day-ahead regional market. There are unintended consequences of this regulatory failure:

- Out-of-state fossil resources are receiving a windfall due to higher energy prices. The CAISO’s accounting system credits imports of lower marginal cost clean energy into California when these resources would have otherwise dispatched to serve out-of-state load but for the EIM. As a result, overall energy prices and output are increased for fossil resources outside of California, giving these resources a competitive advantage.
- The price of carbon allowances is artificially suppressed by fictitious imports of non-emitting energy resources into the market. As a result of cheaper carbon allowances, in-state sources from all sectors – not just energy – that have their own compliance obligation may increase emissions because such emissions will have a lower compliance cost.
- The price signal to support investment in new out-of-state zero-emissions resources is severely muted because the additional demand for these resources in California is being met through reshuffling of existing resources, with no emissions benefit, rather than through the development of new clean resources.

If and when the CAISO expands to include out-of-state entities in its simultaneous optimal dispatch process, these problems associated with the enforcement of California’s GHG laws will be magnified. An expanded RSO would require accounting for emissions from a much larger quantity of energy—many times larger than EIM transactions— that are sold into California but dispatched as undifferentiated energy into the regional pool. At the same time, in a multi-state RSO, California’s ability to regulate such emissions from power plants outside the state will be constrained by federal law.<sup>9</sup> These issues should therefore be resolved with specific plans for how GHG accounting will be implemented in both the current EIM and any expanded RSO configuration before such expansion occurs.

<sup>4</sup> CARB, “Mandatory GHG Reporting and Cap-and-Trade Program Workshop,” June 24, 2016, p.9 [http://www.arb.ca.gov/cc/capandtrade/meetings/062416/arb\\_and\\_caiso\\_staff\\_presentations\\_updated.pdf](http://www.arb.ca.gov/cc/capandtrade/meetings/062416/arb_and_caiso_staff_presentations_updated.pdf)

<sup>5</sup> *Id.* at p.11

<sup>6</sup> See “MonthlyEIM\_Transfer\_ISO\_Imbalances\_MWh.xlsx.”, available at <http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>.

<sup>7</sup> The resource shuffling appears at this point to be an inadvertent result of EIM rules, rather than a purposeful manipulation of the market by generators.

<sup>8</sup> Health and Safety Code § 38562(b)(8).

<sup>9</sup> See Carlson, Anne and William Boyd, “Evaluation of Jurisdictional and Constitutional Issues Arising from CAISO Expansion to include PacifiCorp Assets,” Aug. 1, 2016, available at: <http://www.caiso.com/Documents/LegalEvaluationOfISOExpansion.pdf>

II. Potential Solutions To GHG Leakage In A Regional Market. There are various proposed responses to address the leakage occurring in the EIM market. Of the proposed solutions, Sierra Club recommends that CARB focus on the following core principles when determining optimal amendments to its GHG regulations:

- The GHG regulations must create a clear short-term price signal that allows consumers and/or the market to select clean generating resources over fossil generating resources.
- The GHG regulations must create a clear and predictable long-term price signal that will support investment in clean energy resources throughout the region, with the confidence that the California's willingness to pay for these resources will not be subverted by accounting gimmicks.
- CARB and CAISO must work together on an accounting system that maintains the integrity and effectiveness of California's existing GHG regulations.
- The solution(s) should be workable in both the EIM and the potential day-ahead regional market.
- The solution should be scalable so that it can accommodate the expansion to more balancing authorities and more states in the region for both the EIM and the potential day-ahead market.

With these core principles in mind, Sierra Club addresses various alternatives.

#### A. Uniform Carbon Adder in the Dispatch

The distortions in the EIM that are resulting in unaccounted for secondary dispatch of high-GHG resources are the result of having a single market with varying GHG price signals in that market. While all resources within the market receive the same energy clearing price, along with a locational component that reflects physical constraints on the system, a two-tiered, non-physical system of carbon price and no-carbon price will inevitably create distortions such as those evidenced in the EIM. As the market continues to grow, it is likely, if not inevitable, that additional tiers will be necessary as different states pursue different carbon pricing policies. The simplest method to avoid these distortions is to remove multi-tier carbon pricing within the market.

A uniform carbon adder, implemented by the regional operator, has been suggested in other regional markets as a method of meeting state carbon policies in a just and reasonable manner.<sup>10</sup> The broad concept would be to incorporate each specific generating source's carbon emissions profile into the dispatch algorithm for the market. For example, each generating resource in the market would be assigned a ton per megawatt hour ("ton/MWh") profile based on unit-specific emission rates. The clearing price in the market would be the combination of the locational energy price plus the carbon price. This would allow the dispatch algorithm to optimize the entire system based on both energy and carbon prices, which sends a consistent price signal to generators regardless of where they originate from or where they dispatch to. Generators would be paid the clearing price times their electrical output, less the dollar-per-ton carbon price times their actual emissions.

CAISO (or the RSO in a multi-state regional market) would collect the difference between the clearing price and the amount paid to carbon-emitting resources, which would create a pool of money based on a uniform carbon price for all power dispatched anywhere in the system. CAISO could then distribute the money collected from the uniform carbon price in a manner that respected each state's climate policies. In other words, CAISO could remit the collected carbon proceeds back to the purchasers in each state based on the tons/MWh attributable to the power delivered to each state. Each state could then apply their own carbon regulations to the utilities or other purchasers in their own jurisdiction in accordance with state policies.

California could implement its carbon policy by assigning a compliance obligation to its own utilities based on their consumption of carbon emitting resources in the market. Those utilities would be responsible for a compliance obligation, but they would remain whole because they would have already been compensated by the CAISO for the cost of carbon delivered to them. In contrast, states without carbon policies could simply direct their utilities to refund the carbon proceeds to ratepayers in order to offset the increase in the market clearing price for energy. As long as generators are prevented from manipulating their energy bids to offset their carbon prices, the appropriate price signal would be sent to all dispatch in the system. This method of applying a uniform carbon price would be relatively simple to administer, and it would eliminate leakage in the system.

#### B. Assigning GHG Costs Only to California Purchasers

CARB's proposed amendments contemplate a solution that would assign the costs of GHG emissions due to secondary dispatch to purchases inside California. This method would first identify all of the unaccounted for out-of-state GHG emissions in the EIM (i.e. secondary dispatch emissions). Purchasers in California, such as California's utilities, would then be assessed a cost based on the total unaccounted for GHG emissions in the market. This solution would address the issue of price suppression in California's carbon allowance market because it would account for and assign costs to the out-of-state emissions that currently are not being tracked. This would reduce or eliminate the effect of suppressing carbon allowance prices due to flooding the market with non-emitting resources.

Although the integrity of the price for carbon allowances would benefit, this solution raises some concerns. First, there would be no price signal in the market that would allow California purchasers to avoid exposure to a compliance obligation. The dispatch of high and low carbon resources would still be managed by CAISO, and the market distortions causing secondary dispatch of fossil resources outside of California would continue. In other words, a California utility would have no control over the number of allowances it would be required to purchase to offset its consumption in the EIM market. That compliance obligation would be assigned after-the-fact. It also means that out-of-state fossil generation would continue to receive a windfall by benefitting from higher out-of-state energy prices without any requirement to pay a compliance obligation to California.

The problem of a “California Purchaser” compliance obligation also becomes more problematic in an expanded day-ahead market. For example, the current plan to transform CAISO into a multi-state RSO would begin with PacifiCorp, which in 2015 generated over 60% of its power from coal. California purchasers could be exposed to substantial compliance obligations in a market that integrated PacifiCorp if CARB determines that there is an increased dispatch of those coal resources anywhere in the region that is attributable to California consumption. Moreover, those California purchasers would have little or no ability to avoid purchasing coal-heavy power in such a market, and the out-of-state generators would not face any disincentive to selling high GHG resources into the market.

#### C. Apply the Unspecified Power GHG Rate to All Out-of-State Generation

This proposed solution would apply a uniform GHG adder to all out-of-state generation that is imported into California, regardless of the source of that generation. This method attempts to approximate the current treatment of unspecified power resources into California markets; it also is a closer approximation to the actual GHG emissions of resources that are dispatched into the EIM. This method is problematic for several reasons.

First, this method would reduce the incentive to provide low or non-emitting resources to California. All out-of-state resources, including wind and solar, would face the same carbon price. This would provide the perverse incentive of disadvantaging non-emitting generation with a carbon price, while at the same time providing a relative advantage for coal generation because coal emits at a much higher rate than the unspecified power rate.

While this may be a palatable interim solution in the EIM, this solution would be unworkable in a day-ahead regional market. Applying a GHG cost to out-of-state renewable resources would reduce or eliminate one of the primary benefits touted by proponents of the regional market, which is the ability to acquire low-cost out-of-state renewable resources to meet California's RPS requirements. While those resources would still be available, adding a carbon price to zero emission wind from Wyoming or New Mexico would drive up the cost of those resources.

#### D. Require CAISO to Dispatch EIM Based Only on Incremental Out-of-State Production

In its September 9, 2016 comments to CARB, Powerex Corp. proposed a solution that would limit “deemed deliveries” in the EIM only to the incremental production from out-of-state resources.<sup>11</sup> Under this method, the CAISO algorithm would treat base schedules as being unavoidable for dispatch into the EIM. This method would reduce the extent of secondary dispatch in the market because it could only select clean resources for dispatch into California if those clean resources had not been previously scheduled to provide out-of-state power. Consequently, there would be smaller gaps to “backfill” with dirty power.

Although this method offers a potential solution to consider in the EIM, one which would require more analysis to understand how the market would respond, the limitation of the market to only consider incremental production would not be feasible in a day-ahead market. In contrast to the EIM, which is an optimized balancing market that only serves residuals from day-ahead commitments, the day-ahead market would schedule all of the available resources within the system and there would be no distinction between base schedules and incremental production. This method could therefore apply only to the EIM and would not address the problems of leakage that would occur in a larger day-ahead market.

III. Conclusion. Sierra Club appreciates the opportunity to provide these comments to CARB and CAISO. The questions surrounding the proper accounting and regulation of GHGs in a multi-state energy market, including both the EIM and the proposed day-ahead market, are critical for the development of a system that will support California's climate goals. These discussions are, however, at an early stage still. None of the alternatives discussed above are perfect. Among the options discussed, Sierra Club favors the uniform carbon dispatch price because of its relative simplicity and the effectiveness of stopping leakage in the system. It is important therefore to solicit comments and ideas from other states, both on the proposals discussed above and on other proposals for regulating carbon in a multi-state RSO.

Sierra Club encourages all stakeholders to meaningfully engage in this topic so that solutions can be developed in time to inform the ongoing discussions about the proposed transition of CAISO into a multi-state RSO. (SC1)

**Comment:** Issues surrounding the necessary revisions to the Cap-and-Trade Program to address potential inaccuracies in renewable energy and electricity imbalance market (EIM) accounting have been the subject of considerable deliberations and extensive stakeholder meetings, and are flagged in the proposed amendments to the Cap-and-Trade Regulation as matters that require further studies and analysis before they can be fully resolved and requiring proposed revisions to be reflected in 15-day changes. Given the interaction between these two regulations and the broader implications for California's energy markets, any proposed changes to the MRR should similarly reflect the need for further analyses and potential changes in 15-day language. (MSR1)

**Comment:** Section 95111(h) – Reporting requirements for the California Independent System Operator (CAISO) Energy Imbalance Market (EIM). The proposed amendment specifies the reporting methodology required for the CAISO to calculate unspecified electricity imports into California in response to the Energy Imbalance Market (EIM). We support ARB's goal to minimize emissions leakage and propose that ARB refine this section to ensure that it aligns with the regulatory language being developed in the Cap-and-Trade regulation. (PGE1)

**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. (SCE1)

**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.<sup>2</sup> As the EIM footprint

<sup>2</sup> ISO 2016 Q2 Report Benefits for Participating in EIM dated July 28, 2016 at 7.  
[http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ2\\_2016.pdf](http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ2_2016.pdf)

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.<sup>3</sup>

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.

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" dispatch<sup>4</sup> 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.

<sup>3</sup> See California Global Warming Solutions Act of 2006, codified at California Health and Safety Code Section 38500 *et seq.*

<sup>4</sup> 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.

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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.<sup>5</sup> 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 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.

<sup>5</sup> ARB Staff Report: Initial Statement of Reasons at 51-52. <https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

<sup>6</sup> See proposed addition of EIM Purchaser to the definitions of ARB’s cap and trade regulation at 17 Code of California Regulations Section 95802.

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.*<sup>6</sup>

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.<sup>7</sup> 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 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.

<sup>7</sup> 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.

\* \* \*

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.<sup>14</sup>

<sup>14</sup> ARB Staff Report: Initial Statement of Reasons at 10-11.  
<https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

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.

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-FactualComparison-PreliminaryResults\\_Jan-Jun\\_2016\\_.pdf](http://www.caiso.com/Documents/EIMGreenhouseGasCounter-FactualComparison-PreliminaryResults_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.<sup>15</sup> 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.

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<sup>15</sup> 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.

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.

III. 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 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.

- IV. Conclusion. 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. (CAISO1)

**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. (MID2)

**Response:** In the 45-day amendments, staff proposed changes to ensure the full accounting of emissions from imported electricity under the Energy Imbalance Market (EIM) operated by the California Independent System Operator (CAISO). Modifications were made to ARB's proposal through the 15-day packages, which address many of the concerns voiced by stakeholders, as described below.

Under AB 32, ARB must account for statewide GHG emissions, including all emissions resulting from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution lines losses, whether that electricity is generated in-state or imported to California to serve California load. To account for GHG emissions in the electricity sector California power plants must report their emissions under MRR based on fuel type or using continuous emissions monitoring systems. Under the Cap-and-Trade Program each of these generators has a compliance obligation for the emissions that result from their electricity generation. To account for GHG emissions resulting from out-of-state power plants serving California load, electricity importers must report physical delivery of electricity

by generation source, allowing ARB to account for the emissions profile of imported electricity by fuel type of the generation source. Under the Cap-and-Trade Regulation the importer has a compliance obligation associated with the emissions from imported electricity that serves California load.

The deemed delivery mechanism in the current EIM algorithm creates a scenario in which specific resources are deemed to serve California load without fully capturing emissions resulting from the imported electricity. Although MRR correctly reflects entities identified as EIM importers, who have decided to import power to California, CAISO's algorithm itself incompletely covers emissions associated with electricity serving California load. This operation of the EIM market generates emissions associated with California electricity demand that the current regulation does not fully capture. 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.

ARB released "Attachment B: Analysis of the Energy Imbalance Market and Mandatory Greenhouse Gas Reporting and Cap-and-Trade Regulations,"<sup>14</sup> on December 21, 2016 as part of the first 15-day rulemaking amendments for MRR. This analysis, conducted by ARB staff, describes the impact on GHG emissions from the current EIM market design. ARB's analysis found that the current EIM market design was resulting in underreporting of GHG emissions through its resource attribution methodology, and that as EIM expands to include each additional balancing authorities, the quantity of emissions being underreported would increase. While ARB cannot calculate the exact scale of this projected increase in underreporting, ARB must be conservative in assessing the emissions that are underreported, and any identified underreporting necessitates modifications to the regulation under AB 32's mandate to minimize emissions leakage.

ARB and CAISO have jointly and individually consulted with stakeholders and considered various options to fully account for GHG emissions into the atmosphere that occur in connection with EIM transfers into California to serve California load. CAISO is currently developing a 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. In the interim, with input from CAISO and stakeholders, ARB has developed a solution through this regulatory amendments process for MRR and the Cap-and-Trade Regulation intended to act as a bridge

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<sup>14</sup> <https://www.arb.ca.gov/regact/2016/ghg2016/attachb.pdf>



to support accurate accounting while the longer-term two-pass market optimization is being developed by CAISO.

As a result of this consultation, staff has developed a workable interim solution throughout the course of this rulemaking process. As a result, many of the comments above critiquing the solution initially proposed in the 45-day comment period have functionally been addressed by later refining amendments made in part to respond to stakeholder feedback. Following 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. Staff removed the term “EIM Purchaser” from the regulation and modified definitions accordingly. 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. The current proposal for EIM-imported electricity requires EIM participating resource scheduling coordinators to continue reporting as they currently do under MRR. It also requires CAISO to report information annually to ARB under a subpoena that would allow ARB to calculate the amount of emissions (“outstanding emissions”) to support full accounting of GHG emissions emitted to the atmosphere when there is dispatch to serve California load during periods of imbalances. The outstanding emissions will be calculated 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 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 changes in California demand. For more information on the appropriateness of the default emission factor for this analysis, please see page 5 of Attachment B that is referenced above.<sup>15</sup> 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 in the Cap-and-Trade Regulation, as the 2017 FSOR for that regulation explains.

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<sup>15</sup> 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.

ARB's proposed interim regulatory solution does not address issues that are inherent in the CAISO EIM due to the design of the EIM model that stakeholders have identified in their comments. 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.

<sup>16</sup> 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 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.

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 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

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<sup>16</sup> 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>

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 the amendments.

#### **F-11. Comment: *CAISO as Reporting Entity***

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.<sup>11</sup>

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.<sup>12</sup> 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 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.<sup>13</sup> 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.

<sup>11</sup> ARB Staff Report: Initial Statement of Reasons at 9.  
<https://www.arb.ca.gov/regact/2016/ghg2016/ghgisor.pdf>

<sup>12</sup> California Health and Safety Code Section 38530(b)(1).

<sup>13</sup> 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).

(CAISO1)

**Response:** While staff proposed in the 45-day amendments to include electricity data reporting for CAISO, ARB withdrew this proposal in second 15-day amendment package. ARB appreciates the ongoing commitments CAISO has made, including in comments on this rulemaking, to ensure that accurate information is provided. Therefore, ARB has addressed this comment.

#### F-12. Multiple Comments: *EIM Safe Harbor*

ARB also proposes to modify the safe harbor provisions associated with the prohibition against resource shuffling to exclude the EIM.<sup>8</sup> 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.<sup>9</sup> 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."<sup>10</sup> ISO market dispatches do not meet this definition because they are not a plan, scheme or artifice undertaken by a first deliverer 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.

<sup>8</sup> See proposed changes to cap and trade regulation section 95852(2)(a)(10).

<sup>9</sup> ARB Staff Report: Initial Statement of Reasons at 156.  
<https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf>

<sup>10</sup> 17 California Code of Regulations at Section 95802(a)(336).

(CAISO1)

**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.”<sup>20</sup> Resource Shuffling is prohibited and a violation of the Cap-and-Trade Regulation.<sup>21</sup> 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.”<sup>22</sup>

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.<sup>23</sup> 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.

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<sup>20</sup> As per § 95802(336) of *California Cap On Greenhouse Gas Emissions And Market-Based Compliance Mechanisms*

<sup>21</sup> *Id.* at § 95852(b)(2)

<sup>22</sup> *Id.* at § 95852(b)(2)(A)(10).

<sup>23</sup> 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*

(CAISO1)

**Response:** The Safe Harbor regulatory provisions raised by commenters are out of scope for this MRR rulemaking as those provisions are in the Cap-and-Trade Regulation. This issue is addressed in the 2017 FSOR for the Cap-and-Trade Regulation.

**F-13. Comment:** 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. 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.” <sup>19</sup>

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<sup>19</sup> ARB Staff Report, p. 51.

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 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~~though there ~~may be~~may be no increase in GHG emissions.

**Conclusion.** Both the RPS and Cap-and-Trade programs are designed to combat climate change. Through these programs, the electric sector currently makes significant contributions toward meeting California's GHG reduction goals. The ARB's regulations should recognize and enhance the value that customers provide through their electric rates that include the cost of these programs. As explained above, the ARB can do this in two ways. First, the ARB should revise its accounting procedures in order to credit RPS investments intended to reduce GHG emissions so that ratepayers do not pay once for RECs and then again for GHG compliance instruments. Second, the ARB should resolve EIM design issues that can result in ratepayers paying a premium for low-emitting resources, while the energy dispatched to serve them might be a high- emitting resources. (ORA1)

**Response:** The commenter requests that ARB revise its accounting procedures for how it credits RPS investments and resolve EIM design issues that purportedly result in ratepayers paying a premium for low-emitting resources. ARB staff is not making any additional revisions in response to this comment because such changes are unnecessary or premature. ARB's MRR and Cap-and-Trade Regulations are aligned with RPS policy goals in that the programs are designed to recognize investments in renewable energy made by California utilities. The proposed language in MRR retains the RPS adjustment, which provides a reduction in the compliance obligation for certain entities meeting applicable requirements, in recognition of investments made by California utilities to meet RPS requirements.

The rules for reporting under EIM, including the reporting methodology under the proposed bridge solution, already recognize zero-emission electricity that is imported to California under EIM. 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.



If the EIM model deems the electricity as coming from a renewable resource, that electricity is assigned a zero compliance obligation for the importer of the electricity. Since EIM deemed delivered electricity is considered specified electricity and is directly delivered to California, it is not eligible for the RPS adjustment, which only applies if the electricity is not directly delivered to California. Under the bridge solution, there is no additional direct cost to importers or their ratepayers for the EIM Outstanding Emissions, as those emissions are being accounted for by the retirement of allowances that are not sold at auction. Once CAISO has designed and implemented, with ARB consultation, an effective two-pass solution, the accounting of GHG costs should be further aligned at the time the EIM model deems the electricity as serving California load. Therefore, given the current state of the EIM model, the commenter's proposal is unnecessary and premature.

## **G. Miscellaneous Comments**

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### **G-1. Comment: *Allowances***

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. (CALPINE1)



**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-2. Comment: *Continue Allowance Allocation***

As noted above, Metropolitan supports ARB's proposal to continue an allowance allocation to Metropolitan through 2020 and in post-2020 budget years. (MWDSC1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-3. Comment: *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 alignment of the highest tier would sufficiently limit opportunities for arbitrage. (CALPINE1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

#### **G-4. Comment: *Proposed Clean Power Plan***

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 CO<sub>2</sub> 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.

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. (CALPINE1)

**Response:** These comments are out-of-scope because they address the Compliance Plan and not the amendments to the MRR at issue here. ARB appreciates the support for its proposed Compliance Plan, and agrees that linking with broader markets is an important future opportunity that could increase market efficiency under some circumstances, and which will be carefully evaluated by staff for consistency with California law and environmental integrity requirements should the opportunity arise. ARB looks forward to continuing its work with stakeholders to develop the Compliance Plan, as well as exploring other opportunities to link with broader markets.

#### **G-5. Multiple Comments: *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."<sup>5</sup> 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.<sup>6</sup>

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,<sup>7</sup> 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.<sup>8</sup>

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.) ...”<sup>9</sup> 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 Cap- and-Trade Regulation may be utilized as the Clean Power Plan compliance measure for the state. Therefore, 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.

<sup>5</sup> Health and Safety Code Section 38510.

<sup>6</sup> Id. Section 38566.

<sup>7</sup> See id. Sections 38560, 38562(a) and 38562(g).

<sup>8</sup> 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.”).

<sup>9</sup> Health and Safety Code Section 39602.

(CALPINE1)

**Comment:** The State Board lacks authority to act on these proposed regulations. Staff proposes amendments to various provisions of the Cap and Trade regulations to extend the program after 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. \_\_, § 2, p. \_\_ (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. (FWW1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

#### **G-7. Comment: *Cap-and-Trade Reduction Goals***

The Proposed Amendments largely continue the current system of GHG reductions which relies, in part, on a free market system of allowance auctions and offset programs designed to allow polluting entities flexibility to avoid meeting their own emissions limits. Any market-based approach to pollution control is rife with a significant lack of transparency, while being open to manipulation and fraud, and cannot result in the kind of real, additional and verifiable GHG reductions needed to save this planet from the worst impacts of climate change. In fact, a lack of transparency is already a hallmark of

the state's cap-and-trade program as citizens are not even provided information about who is purchasing emissions allowances or in what amounts.

### Previous Failed Experiments in Market-based Solutions in California

The current carbon cap-and-trade approach is not California's first foray into market-based systems for air pollution control. In the 1990s, while Congress enacted Title IV of the Clean Air Act, the city of Los Angeles was experimenting with its own air trading approaches to cut down on several pollutants. Rule 1610 was approved in 1993. It allowed stationary sources of air pollution (typically LA's oil refineries) to purchase emissions credits from scrapyard operators who were removing older, highly polluting cars off the roads. The pollutants traded were volatile organic compounds, or VOCs.

The Rule 1610 program underscored many of the inherent problems with trading programs. Scrapyards were removing engines from old vehicles before demolishing them and selling both the engine and the emissions credits to increase profits. The oil refineries, all located in clusters among communities of color, continued to emit VOCs, along with many other co-pollutants such as benzene, a known carcinogen. These increases in stationary source emissions led to localized hotspots of increased impairment.

The early 1990s also saw Los Angeles introduce the Regional Clean Air Incentives Market, or RECLAIM, to try to reduce smog in the region. Pre-RECLAIM regulatory approaches showed dramatic reductions in many smog-related pollutants, including nitrogen oxides (NOx). These reductions stopped abruptly with the implementation of the new market system. In fact, for the first two years of RECLAIM, emissions actually increased, with only minor reductions (3 percent) in the years following. RECLAIM never did reach its goals. According to an April 2001 article in the Los Angeles Times, one month before the program was scrapped:

Manufacturers, power plants and refineries have reduced emissions by a scant 16 percent — much less than was anticipated by this time. Businesses were given 10 years to eliminate about 13,000 tons of pollution annually, but as the program nears its end they have eliminated just 4,144 tons.

RECLAIM also shares a major problem with all trading programs: it de-motivated technological advances to pollution control, allowing industries to rely on credit purchasing instead of innovation to reduce emissions. The 10 years of RECLAIM were, in effect, a decade lost on making any significant inroads on LA's air problems.

### The Acid Rain Program is not a Cap-and-Trade Success Story

Even where cap-and-trade systems have, arguably, resulted in decreases in emissions, they have proven to be less effective than direct source-by-source approaches. Title IV of the 1990 Clean Air Act Amendments, known as the Acid Rain Program, or ARP, has become the poster child for pollution trading proponents. It was enacted to address the

main causes of acid rain — the emission of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) from coal-fired power plants — through a system of buying and selling emission allowances. The goal of ARP was to reduce annual SO<sub>2</sub> emissions to about 9 million tons by 2010, down from the 15.7 million tons emitted in 1990.

While recent modeling indicates that this reduction target was reached by 2007, it remains far from clear whether the reductions were due to pollution trading or in spite of trading. For example, we know that the U.S. Environmental Protection Agency (EPA) now attributes at least 1 million tons of SO<sub>2</sub> reductions during ARP to factors unrelated to trading, namely the increased availability and switch to low-sulfur coal sources from the Powder River Basin in the early 1990s.

Prior to the enactment of Title IV, an assessment projection indicated that reductions in SO<sub>2</sub> as great as those achieved under a market-based ARP could be attained if older coal-fired power plants simply complied with the Clean Air Act's New Source Review (NSR) technology retrofitting requirements. But with the introduction of trading, those technological modifications fell by the wayside. As one 2005 report indicates, "Experience since 1990 has shown that most of these facilities have managed operations to avoid triggering NSR, resulting in facility life being extended longer and adoption of new control technologies being slower than many analysts predicted in 1990."

While we may never know the real impact of substituting trading mechanisms for technological upgrades on U.S. SO<sub>2</sub> emissions, results from Europe's contemporaneous acid rain approach indicate that we would have done much better sticking with regulatory approaches. A 2004 comparative study of the U.S. trading approach to SO<sub>2</sub> with the European Union's and Japan's regulatory "command and control" systems show a much greater reduction without trading. While the United States attained a 39 percent reduction in SO<sub>2</sub> during Phase I of the ARP program, the EU achieved a 78 percent reduction. Japan's emissions fell by 82 percent.

The ARP could only be considered a successful trading program if you ignore the reductions we would have achieved had we continued to force these industries to comply with the law and upgrade their reduction technology, without allowing trading.

#### European Union Emissions Trading System: Another Failed Experiment in Market-Based Solutions

While we still may not know what impact California's cap-and-trade initiatives have had on actual GHG reductions in the state, we do know that the largest existing carbon market in the world – the European Union's – has, like RECLAIM and Rule 1610, been an abject failure in many ways. With a total value of \$176 billion, the biggest pollution marketplace experiment is the ongoing European Union Emissions Trading System (EU ETS). It was included as one of the mechanisms for meeting national emissions targets under the Kyoto Protocol to reduce climate-altering greenhouse gas emissions from industries around the globe

Thirty countries are part of this regional cap-and-trade system. The EU ETS only covers certain sectors, such as power generation and steel manufacturing, but not others, such as transport and agriculture. The EU ETS aims to reduce CO<sub>2</sub> emissions in these sectors 20 percent by 2020. Trading started in 2005. It has been fraught with significant problems and, at times, seems to be teetering on complete collapse. As was recently the case in the California allowance market, the price for carbon in the EU ETS has been incredibly volatile. It reached €30 (\$47) in 2008, languished below €10 for most of 2012, hitting a low of €5.99 in April of that year. This kind of volatility undermines economic planning, while allowing some companies to reap a windfall with over-allocation.

The EU ETS has also attracted hackers and outright fraud, culminating in shutting down the spot market in 2011 after a group of Eastern European hackers cost EU governments up to €5 billion in an attack. From stolen and fraudulent credits to stockpiling, plunging demands and miscalculated caps, the carbon cap-and-trade program has more problems associated with it than any traditional regulatory program could.

#### Offsets Do Not Achieve Real, Permanent or Additional Emission Reductions

Perhaps one of the most troubling aspects of the current market-based system is the use of offsets in lieu of source reductions. Regardless of whether the proposed offsets occur within or without the state cap-and-trade program, any kind of offset is a legitimate threat to achieving real, additional, or permanent emissions reductions. Offsets allow polluters to avoid the urgent need to stop polluting and instead allow them to pay to continue their harmful activities with impunity, while claiming that emissions have been reduced elsewhere. Moreover, the agenda behind offsets, as is clear here, too often places priority on cost containment, market efficiency and making it easier for polluters to comply, disregarding the true priority of reducing GHG emissions.

The issue of permanence presents the most egregious problem from offsets. The dictionary defines permanence as “the state or quality of lasting or remaining unchanged indefinitely.” However, ARB’s understanding of permanence is quite distorted: “Permanent means, in the context of offset credits, either that GHG reductions and GHG removal enhancements are not reversible, or when GHG reductions and GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions and GHG removal enhancements to ensure that all credited reductions endure for at least 100 years.”

ARB’s interpretation sends the contradictory message that offset protocols require permanence, but then allows for situations where permanence can be violated as long as there are backup mechanisms in place. For example, the Forest Buffer Account exists for when a forest used for offsets might burn down or be destroyed by another natural disaster, reversing the offsets generated. However, what’s left unsaid is that using a buffer account like this allows the total amount of emissions released to

increase — the reversed offsets release emissions, requiring more offsets to replace those reversed, ultimately increasing the aggregate number of credits used and subsequently increasing the overall amount of emissions allowed. It's not as simple as a one-for-one exchange.

Additionally, offsets conflict with the requirement for permanence when the life of the reductions is only 100 years, instead of achieving true permanence. Crediting periods also contradict the concept of permanence when they only go for 25 or 30 years at a time. This is, again, not permanent. It is also unclear what happens after the crediting periods end, or after the 100 years of "permanence" end. The companies that issue the offset credits might not exist in 25, 30 or 100 years, and these impermanent crediting periods bring all of the offsets issued into question. The entire structure presents a significant risk of large-scale reversal in the future, undoing whatever emission reductions might happen and creating no real progress on the very critical issue of GHG reductions.

Another problem arises in the methodology for measuring the amounts of carbon dioxide (CO<sub>2</sub>) stored in forests and as well as the methods for calculating emissions reductions from the proposed rice cultivation offsets. Although both methodologies are problematic, they share a significant issue in that they use models and estimates to arrive at the amount of CO<sub>2</sub> stored in a forest or the amount of methane emissions prevented from different rice cultivation practices. From these estimates, offsets are then sold for exact amounts of avoided emissions. A modeled estimate does not equal an exact amount of emissions. It doesn't add up.

Additionality issues also render California's offset program invalid. State regulations hold that, "A registry offset credit must represent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable" (Health and Safety Code §38562(d)(1) and (2)). Yet time and again, ARB approves offsets that do not meet this additionality requirement.

For example, Brubaker Farm in Pennsylvania built a manure digester in 2011, using taxpayer funding, to provide electricity for the farming operation. The owner of the farm is on record as saying he originally built the digester not for credits, but for electricity. Yet, in 2015 ARB retroactively certified the Brubaker digester as a GHG offset generator, and California industries can now take advantage of this facility to continue their own emissions even though the digester was already in place, and operating.

Likewise, ARB recently approved the 704-acre Pungo River Forest Conservation Project in North Carolina as a source of GHG offsets even though this stand of forest was put into permanent conservation easement in 2003. Seeking out already existing projects across the country to generate GHG reductions and subsequent offset credits for use in the state of California means that there are no additional GHG reductions taking place through the state's offset program.



The lack of accountability in offset approaches is not restricted to California. A recent study of a European Union offset program found that 80% of credits were unverifiable. This means that polluters were able to buy offset credits to pollute more from sources that may or may not have actually reduced emissions.

#### Cap-and-trade Undermines the Clean Air Act

The offset approach is not the only problem. Cap-and-trade is a regulatory framework that seeks to eliminate the most important tenets of the Clean Air Act, which is that companies do not have an inherent right to pollute. Under cap-and-trade policies, polluters are being given a right to threaten public health and the environment, as long as they pay for it. These schemes essentially create loopholes that allow polluters to continue dumping and discharging rather than holding them accountable for pollution.

Trading creates a mechanism where profits determine who is able to pollute and can actually lead to an overall increase in pollution along with regional pollution hot spots, as larger and well-financed polluters will often opt to purchase credits rather than run pollution control equipment. This happened with the Los Angeles air pollution trading programs under the Rule 1610 and RECLAIM programs in which communities of color near the City's refinery district suffered from increased air pollution when these facilities purchased emissions credits instead of installing reduction technologies.

While proponents of cap-and-trade and offsets tout the regulatory flexibility benefits of these policies, in reality these policies allow polluting industries to put profit above the interests of public health and the environment. We need to strengthen protections under the Clean Air Act that have worked for decades to help hold polluters accountable, rather than rolling back some of the most important public health laws for decades.

The threats posed by climate change to our public health, environmental health, communities and livelihoods are permanent and real, and so must our efforts to stop these threats be permanent and real — cap-and-trade and offsets cannot accomplish this. The fact that they require loopholes, distortions and exceptions to even “work” shows that these approaches are not a solution to our climate problem, but simply exist as conveniences for industries that wish to avoid taking the steps necessary to limit their own pollution emissions. (FWW1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

#### **G-8. Comment: *Definition of Wholesale Water Agencies***

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. (MWDSC1)

**Response:** The cited definition is in the Cap-and-Trade Regulation, and is not used in the Mandatory Reporting Rule, so it is out of scope for the MRR rulemaking. This comment is addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-9. Comment: *Cap-and-Trade Regulation, Multiple comments***

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.

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.

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.

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.

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.

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.

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.

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, EDUs 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.

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")<sup>1</sup>. 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 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.

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<sup>2</sup>. 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 PCC2<sup>3</sup> 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 POU's like MID, have grandfathered, or PCC0 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 staffs RPS adjustment replacement does not recognize EDU ratepayers' investments in PCC0 resources. MID will have 45% of its 2030 RPS compliance fulfilled by PCC0 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 2021-2030<sup>4</sup>.

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 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.

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.

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MID thanks ARB for its consideration of our comments on these important issues. MID urges ARB to be mindful of the significant cost impacts that the amendments in the Proposed Regulation Order might have on California's ratepayers, particularly regarding the RPS adjustment and direct industrial allocation.

<sup>1</sup> *Staff Report: Initial Statement of Reasons*, August 2, 2016, California Air Resources Board, p. 33

<sup>2</sup> 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.

<sup>3</sup> The RPS "bucket 2" electricity, which is sourced from out-of-state firmed-and-shaped electricity contracts.

<sup>4</sup> Based on the CEC's 2015 IEPR allowance price forecast.

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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 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.

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 importer s 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 951102(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 951 02(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 patty 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 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 meet s 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 and is claimed as a specified source by an electricity importer is directly delivered.

(MID2)



**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

## **V. SUMMARY OF COMMENTS MADE DURING THE FIRST 15-DAY COMMENT PERIOD AND AGENCY RESPONSE**

Chapter V of this FSOR contains all comments submitted during the first 15-day comment period, with ARB's responses. The first 15-day comment period for additional proposed amendments commenced on December 21, 2016, and ended on January 20, 2017.

ARB received 23 letters on the proposed 15-day amendments during the 15-day comment period. Table V-1 below lists commenters that submitted oral and written comments on the proposed amendments, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day and 15-day comment periods are available here: <https://www.arb.ca.gov/regact/2016/ghg2016/ghg2016.htm>

This rulemaking is for amendments to the ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. However, comments were also submitted to this rulemaking which relate to the separately noticed Cap-and-Trade Regulation, which is outside the scope of the proposals identified in the Staff Report, Notices of Modified Regulatory Text, and this FSOR. Statute only requires responses to comments directly submitted as part of a specific rulemaking, and this FSOR provides responsive comments only to those comments related to this specific rulemaking.

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/ghg2016/ghg2016.htm>

### **A. LIST OF COMMENTERS**

**Table V-1**

<b>Abbreviation</b>	<b>Commenter</b>
JSAV1	John Savage, Private Citizen Written Testimony: 1/4/2017
PWP1	Gurcharan Bawa, Pasadena Water and Power Written Testimony: 1/19/2017
WPTF2	Clare Breidenich, Western Power Trading Forum Written Testimony: 1/20/2017
JU1*	Adrianna Kripke, Joint Utilities Representing Nine Utilities Written Testimony: 1/20/2017 (*identical comments submitted twice)

<b>Abbreviation</b>	<b>Commenter</b>
AMGAS2	Michael P. Daly, Amerigas Written Testimony: 1/20/2017
VEA2	Daniel J Tillman, Valley Electric Association Written Testimony: 1/20/2017
CCPC3	Shelly Sullivan, Climate Change Policy Coalition Written Statement: 1/20/2017
FE3	Jay Wintergreen, First Environment Written Testimony: 1/20/2017
CALPINE2	Barbara McBride, Calpine Corporation Written Testimony: 1/20/2017
PACCORP1	Mary Wiencke, Pacificorp Written Testimony: 1/20/2017
EIM-ENT1	Mary Wiencke, EIM Entities Written Testimony: 1/20/2017
CAISO2	Andrew Ulmer, California Independent System Operator Written Testimony: 1/20/2017
SCPPA2	Sarah Taheri, Southern California Public Power Authority Verbal Testimony: 1/20/2017
JU1*	Adrianna Kripke, Joint Utilities Representing Nine Utilities Written Testimony: 1/20/2017 (*identical comments submitted twice)
SDGE2	Tim Carmichael, SDG&E Written Testimony: 1/20/2017
CALCHAMBER2	Amy Mmagu, CalChamber Written Testimony: 1/18/2017
TID3	Ken Nold, Turlock Irrigation District Written Testimony: 1/20/2017
PGE3	Mathan Bengtsson, PG&E Written Testimony: 1/20/2017
SMUD3	William Westerfield, SMUD Written Testimony: 1/20/2017
PWX2	Nico van Aelstyn, Powerex Written Testimony: 1/20/2017
CMUA2	Justin Wynne, California Municipal Utilities Association Written Testimony: 1/20/2017
ORA2	Julie Halligan, Office of Ratepayer Advocates, California Public Utilities Commission Written Testimony: 1/20/2017
LADWP3	Mark Sedlacek, Los Angeles Department of Water and Power Written Testimony: 1/20/2017

## **B. MRR General Reporting Regulation Comments**

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### **B-1. Comment: *Update of GWP Values***

Despite its long-standing leadership on climate, one important area where ARB's climate policies have lagged behind both US federal and global standards is in regard to its use of outdated GWP's for short-lived pollutants.

Now, despite its proposed changes to update some of these GWP's, ARB will continue to be a laggard in this area, which is disappointing given the increasing importance scientists are placing on short-lived pollutants in the overall climate change picture.

By the time ARB implements its proposed changes, the EPA and UNFCCC may well have moved to, at minimum, the AR5. It seems like ARB will always be out of lockstep with national and international reporting when that really shouldn't be the case. California should continue to lead, not lag.

Please consider using the most current GWPs going forward rather than continuing to lag behind the rest of the world in this important area. (JSAV1)

**Response:** Please see the response to Comment B-1 in section IV of this document, which addresses a similar comment made during the 45-day comment period for this rulemaking.

### **B-2. Comment: *Regulatory Process Concerns***

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.

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.

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. (SCPPA2)

**Response:** This rulemaking complies with the full requirements of the Administrative Procedures Act. In addition to providing proposed amendments through the formal rulemaking process, staff began engaging with stakeholder through public workshops and individual meetings in late 2015 and early 2016 on areas where regulatory clarification was needed and on concepts for potential regulatory amendments. Throughout 2016 and into 2017, staff also released guidance and closely worked with stakeholders regarding the updates that are included in proposed amendments. The proposed amendments largely do not introduce new requirements, but serve to clarify existing requirements. In addition, staff held a series of informal public workshops on various topics on December 14, 2015, February 24, 2016, June 24, 2016, and October 21, 2016. The workshops focused on the Federal Clean Power Plan, the RPS adjustment, potential MRR updates for various sectors, including changes for the electricity and natural gas sectors, and the proposed verification deadline change. Staff crafted the proposed amendments submitted in the 45-day Regulation based on stakeholder feedback as a result of the workshops and extensive stakeholder

outreach. Further stakeholder input was solicited and incorporated into the rulemaking process through two 15-day comment periods which occurred in December 2016 and April 2017. In addition, staff has made itself available extensively in one-on-one meetings and teleconferences with affected stakeholders to discuss the requirements reflected in the proposed amendments. In some cases, staff also provided draft concept language to stakeholders prior to final publications, and made every effort to address all concerns prior to the release of regulatory documents. In addition, the public process for this item was further enhanced by providing not just one, but two Board meetings, with full public testimony at each meeting. The first Board meeting was held on September 22, 2016, and the second was on June 29, 2017, substantially extending the overall time frames to incorporate all relevant stakeholder input.

**B-3. Comment: *Sections 95105(b) – ARB Record Requests***

PG&E appreciates the increase from 10 to fourteen business days to respond to records requests. While we maintain the suggestion that the regulation specifically indicate business days, the provision that additional time may be granted if an agreement is reached with ARB may provide the adequate flexibility in the case of larger records requests. (PGE3)

**Response:** Staff appreciates support for the change. Please note that the currently proposed revisions are for 14 calendar days, not business days, as mentioned in the comment.

**B-4. Comment: *Sections 95105(c)(3) – Block Diagrams***

PG&E appreciates ARB's modification of this section to clarify that the necessary diagrams refer specifically to combustion emissions. As PG&E noted previously, requiring diagrams for minor equipment such as valves and pneumatic devices would be difficult and of limited value. (PGE3)

**Response:** Staff appreciates support for the change.

**B-5 Comment: *Section 95112(e) Geothermal Generation Clarification***

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.<sup>3</sup>

<sup>3</sup>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>. (CALPINE2)

**Response:** Staff appreciates support for the change, and the clarifications provided by the commenter during the Regulation update process.

**B-6. Comment: Sections 95131(c)(4)(B), 95131(c)(5), (f) and (g) – *Timing Requirements for Requests from ARB***

PG&E appreciates the change in reporting requirement from five to 14 days. (PGE3)

**Response:** Staff appreciates support for the change.

**C. Fuel Supplier and Biofuel Reporting Requirements**

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**C-1. Comment: *Definition of "Importer of Fuel"***

AmeriGas Strongly Supports the Proposed Amendments to the Importer of Fuel Definition

As outlined in our initial comments,<sup>7</sup> AmeriGas strongly supports the ARB promoting the goals of AB 32 in maintaining a robust and accurate greenhouse gas reporting program through the amendments to the MRR when necessary. ARB's effort to modify the point of regulation for importers of LPG will help further of those goals by preventing leakage.<sup>8</sup> AmeriGas is concerned that certain fuel importers could avoid the cost of compliance with the MRR by transferring ownership to fuel outside of California prior to importation and thereby disaggregating emissions positions among their customers or other distributors they have arranged to serve their customers. AmeriGas strongly supports amending the "importer of fuel" definition to address these concerns.

Suggestions for Further Clarification of Proposed Definition of Importer of Fuel

AmeriGas suggests the following clarifying edits (clean and redline) to the proposed definition of "importer of fuel" to help ensure disaggregation and leakage is avoided:

Clean: “Importer of fuel” means an entity that imports fuel into California and who is the importer of record under federal customs law. For fuel imported into California that is not subject to federal customs law, the “importer of fuel” is the owner of the fuel upon its entering into California if the eventual transfer of the ownership of the fuel to an end-user located inside California occurs at a location inside of California. However, if the transfer of ownership of the fuel to an end-user located in California occurs at a location outside of California, then the “importer of fuel” is the producer, marketer, or distributor that is the seller of the fuel to the end-user. Further, however, if the transfer of ownership of the fuel destined for an end-user located in California occurs at a location outside of California between a seller(s) and buyer(s) where any party is a producer, marketer or distributor and a seller has a contractual obligation to serve the end-user in California, then the “importer of fuel” is such seller. Pursuant to section 95122, only importers of liquefied petroleum gas, compressed natural gas, and liquefied natural gas are subject to reporting as an importer of fuel.

Redline: “Importer of fuel” means an entity that imports fuel into California and who is the importer of record under federal customs law. For fuel imported into California that is not subject to federal customs law, the “importer of fuel” is the owner of the fuel upon its entering into California if the eventual transfer of the ownership of the product between the seller and the fuel to an end-user located inside California buyer occurs upon delivery to a destination at a location inside of California. However, ~~whereif~~ the transfer of ownership of the ~~product between the seller and the~~ fuel to an end-user located in California buyer occurs at a location outside of California, then the “importer of fuel” is the producer, marketer, or distributor that is the seller of the fuel ~~that is forwarding the fuel in accordance with a contract of sale from an origination to the end-user.~~ Further, however, if the transfer of ownership of the fuel destined for an end-user located in California occurs at a location outside of California to a buyer located inside between a seller(s) and buyer(s) where any party is a producer, marketer or distributor and a seller has a contractual obligation to serve the end-user in California, then the “importer of fuel” is such seller. Pursuant to section 95122, only importers of liquefied petroleum gas, compressed natural gas, and liquefied natural gas are subject to reporting as an importer of fuel. (AMGAS2)

<sup>7</sup> Comments of AmeriGas Propane, L.P. to Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, September 12, 2016 at 1-2.

<sup>8</sup> Notice at 5.

(AMGAS2)

**Response:** ARB staff is proposing additional changes to the definition of “Importer of Fuel” based on the information provided by Amerigas. Also see the response to Comment C-1 in Section IV of this document that addresses similar comments received during the 45-day comment period

## **D. Product Data Reporting**

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No comments related to product data reporting were submitted during the first 15-day comment period.



## **E. Verification Requirements**

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### **E-1. Multiple Comments: *Verification Deadline Change***

**Comment:** Pasadena Water and Power (PWP) does not support the bringing forward of the verification statement deadline to August 15th. 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 deadline is necessary, we are recommending a compromise deadline of August 15th instead of August 1st. (PWP1)

**Comment:** Our comments today respond to the California Air Resources Board's (ARB's) proposed amendments to the regulation for the Mandatory Reporting of Greenhouse Gas Emissions released on December 21, 2016.

CCPC continues to be 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, in the most recent ARB/MRR staff report released on December 21, 2016 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.

Alternatively if ARB feels strongly about moving forward with the August 1<sup>st</sup> deadline, we would request:

- ARB consider 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 looks forward to indications from the staff MRR report that states, “*Staff plans to hold a workshop in early 2017 to further discuss the verification deadline....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.*”  
(CCPC3)

**Comment:** First Environment offers the following comments regarding proposed revisions to Mandatory Reporting Regulation. Consistent with our previous comments on this issue, First Environment does not support revision of the verification deadline from September 1 to August 1 without further revisions to the regulation to facilitate meeting this earlier deadline. Changing the deadline without making appropriate changes to the MRR to facilitate meeting the deadline will potentially result in a less impartial and/or rigorous verification process, less accurate GHG reports submitted to ARB, and a higher risk of missing the verification deadline for reporters which could result in enforcement action. If ARB changes the verification deadline from September 1 to August 1, First Environment proposes the following additional revisions to the regulation to facilitate successful verifications by the earlier date:

1. Relative to 95105, establish requirements for uploading specified supporting documentation to Cal eGGRT at the time the GHG report is submitted. We propose, at a minimum, that this documentation should include but not be limited to:
  - a. Statement on operational control and related entities
  - b. Electricity purchases/acquisition records
  - c. Natural gas purchases/acquisition records
  - d. Evidence of unit nameplate capacities
  - e. Air district permits
  - f. Internal meter calibration records
  - g. Gross and net generation data
  - h. Thermal energy generation data
  - i. Product data evidence
  - j. Records associated with any issue ARB defines as a high risk issue (e.g. contracts for biomass derived fuel)
  - k. Specified source contracts for EPEs
  - l. Specified source generation meter data for EPEs

The verification body should be provided access to these uploaded documents through Cal eGGRT when the reporter selects the verification body in Cal eGGRT to provide verification services.

2. Relative to 95105(c) and 95105(d), establish requirements for uploading these documents to Cal eGGRT, which will encourage reporters to prepare for and begin verification activities earlier. We propose establishing a February 30 deadline for uploading these documents to Cal eGGRT.
3. Relative to 95131(a), establish a regulatory deadline for reporters for submission of the NOVS, which will encourage reporters to prepare for and begin verification activities earlier. We propose a May 30 deadline for submission of NOVS.
4. Relative to 95131(b)(3), establish a regulatory deadline for reporters for completion of verification site visits, which will encourage reporters to prepare for and begin verification activities earlier. We propose a June 30 deadline for completion of verification site visits.
5. Relative to 95131(c)(4), recognizing the proposed shortened verification period, reduce the notification and report correction period to five days.
6. Relative to 95133(e), establish a regulatory deadline for reporters for submission of the COI, which will encourage reporters to prepare for and begin verification activities earlier. We propose a May 1 deadline for submission of COI.

Without these revisions to the MRR, First Environment requests that the verification deadline remain September 1. (FE3)

**Comment:** LADWP is opposed to the proposed amendment that would move the deadline to complete verification of the annual greenhouse gas (GHG) emission reports forward an entire month from September 1 to August 1. LADWP believes the amount of time allotted for verification of an annual GHG emission report should be no less than three (3) months. The verification period needs to be long enough to allow the verifiers to do a good job reviewing the reports, and for the reporter and ARB staff to respond to questions that arise during the verification process.

An August 1 verification deadline for all reports is unreasonable because it would compress the timeframe for verifying complex reports such as the Electric Power Entity report from three (3) months to only two (2) months. In LADWP's previous comments (submitted September 19, 2016), we provided specific examples of the level of detail involved in verifying Electric Power Entity reports and responding to questions. It is not feasible to verify data to this level of detail in less than three (3) months. LADWP recommended a bifurcated approach with two different verification deadlines:

- 1) August 1 for facility level reports that have a reporting deadline of April 10, and
- 2) September 1 for entity level reports that have a reporting deadline of June 1. If needed, facility level reports could apply for an extension of the verification deadline to September 1.

LADWP recommends that ARB reject the proposed one-size-fits-all August 1 verification deadline for all GHG emission reports. The verification deadline should be set based on the amount of time needed to verify the annual GHG emission reports to ensure good quality data, not on the desire to have finalized data sooner. (LADWP3)

**Comment:** 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.<sup>11</sup> CMUA supports maintaining the currently effective September 1 date.

<sup>11</sup> 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>. (CMUA2)

**Comment:** 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.<sup>8</sup> 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.

<sup>7</sup> As provided on page 4 of the notice of availability and summary of changes for the Mandatory Reporting of Greenhouse Gas Emissions. (SCPPA2)

**Comment:** SMUD Supports the Proposed Workshop to Discuss the Verification Deadline Change. SMUD remains concerned that reducing the time allowed for verification from September 1st to August 1st could adversely impact the quality of the

verification process. SMUD is gratified that Staff plans to hold a workshop early this year to hear our concerns and hopefully adjust the verification deadline to accommodate the needs of both Staff and stakeholders. (SMUD3)

**Comment:** Sections 95103(f) and 95103(h)(1) – Verification Requirement and Deadlines. As noted previously, ARB’s proposal to move up the annual verification deadline to August 1, which is maintained in the current MRR revisions, is of critical concern to PG&E. Of the 15 MRR reports that PG&E generates, 13 are verified annually in a complex process that include site visits to facilities located throughout the state. The proposal to move up the verification deadline for such a rigorous process increases PG&E’s risk of untimely reporting, consequential enforcement actions, and loss of Cap-and-Trade allowance allocation. PG&E appreciates that these concerns have been heard by staff to the extent that another workshop to address this issue is anticipated in early 2017. PG&E will certainly participate, with the goal of establishing a verification deadline that allows ARB staff to perform its tasks while also leaving enough time for reporting entities to submit accurate, verified data. (PGE3)

**Comment:** Moving the Mandatory Reporting Regulation (MRR) report deadline to August 1st will significantly burden both reporting entities and verifiers. While we understand that the CARB is interested in moving the date in order to provide more time for internal quality assurance checks, calculation, analysis, and the data notifications and postings needed to complete mandated activities under the cap-and-trade program, this shift will significantly negatively impact the regulated entities which have set up practices around the September 1st deadline.

Regulated entities in the state have incorporated the September 1st into their business practices to ensure that they are complying with the regulations as set forth by the CARB. Therefore, we recommend that you maintain the verification deadline of September 1st. (CALCHAMBER2)

**Response:** Please see the response to comment E-1 in Section IV of this document that addresses similar comments received during the 45-day comment period.

## **E-2. Comment: *Section 95130(a)(2) – 6-year Verifier Rotation Requirements***

PG&E strongly reiterates the suggestion to extend from six to twelve consecutive years the period of time that a third-party verifier can work with the same entity. This change would address a real and practical issue with little risk, as ARB’s robust program to ensure the quality of verifications would safeguard the continued integrity and success of the Cap-and-Trade Program. (PGE3)

**Response:** Please see the response to comment E-5 in Section IV of this document that addresses similar comments received during the 45-day comment period.

### **E-3. Comment: *Availability of ARB-accredited Verifiers***

The MRR revisions do not address the reality that the number of independent, third-party verifiers available has significantly diminished since the MRR was initially adopted. The pool of qualified verifiers is even more limited when accounting for verifiers with sufficient expertise to understand the multiple and complex business operations of a large enterprise like PG&E. The limited size of the verifier pool has introduced risk of non-compliance for PG&E because of the time it takes for a new verifier to both come up to speed on PG&E's complex operations and also complete the necessary verification services in a timely manner. (PGE3)

**Response:** Please see the response to comment E-10 in Section IV of this document that addresses similar comments received during the 45-day comment period.

### **E-4. Comment: *Additional Data Collection for Verification Deadline Change***

First Environment offers the following comments regarding proposed revisions to Mandatory Reporting Regulation. Consistent with our previous comments on this issue, First Environment does not support revision of the verification deadline from September 1 to August 1 without further revisions to the regulation to facilitate meeting this earlier deadline. Changing the deadline without making appropriate changes to the MRR to facilitate meeting the deadline will potentially result in a less impartial and/or rigorous verification process, less accurate GHG reports submitted to ARB, and a higher risk of missing the verification deadline for reporters which could result in enforcement action. If ARB changes the verification deadline from September 1 to August 1, First Environment proposes the following additional revisions to the regulation to facilitate successful verifications by the earlier date:

1. Relative to 95105, establish requirements for uploading specified supporting documentation to Cal eGGRT at the time the GHG report is submitted. We propose, at a minimum, that this documentation should include but not be limited to:
  - a. Statement on operational control and related entities
  - b. Electricity purchases/acquisition records
  - c. Natural gas purchases/acquisition records
  - d. Evidence of unit nameplate capacities
  - e. Air district permits
  - f. Internal meter calibration records
  - g. Gross and net generation data
  - h. Thermal energy generation data
  - i. Product data evidence
  - j. Records associated with any issue ARB defines as a high risk issue (e.g. contracts for biomass derived fuel)
  - k. Specified source contracts for EPEs
  - l. Specified source generation meter data for EPEs

The verification body should be provided access to these uploaded documents through Cal eGGRT when the reporter selects the verification body in Cal eGGRT to provide verification services.

2. Relative to 95105(c) and 95105(d), establish requirements for uploading these documents to Cal eGGRT, which will encourage reporters to prepare for and begin verification activities earlier. We propose establishing a February 30 deadline for uploading these documents to Cal eGGRT.
3. Relative to 95131(a), establish a regulatory deadline for reporters for submission of the NOVS, which will encourage reporters to prepare for and begin verification activities earlier. We propose a May 30 deadline for submission of NOVS.
4. Relative to 95131(b)(3), establish a regulatory deadline for reporters for completion of verification site visits, which will encourage reporters to prepare for and begin verification activities earlier. We propose a June 30 deadline for completion of verification site visits.
5. Relative to 95131(c)(4), recognizing the proposed shortened verification period, reduce the notification and report correction period to five days.
6. Relative to 95133(e), establish a regulatory deadline for reporters for submission of the COI, which will encourage reporters to prepare for and begin verification activities earlier. We propose a May 1 deadline for submission of COI.

Without these revisions to the MRR, First Environment requests that the verification deadline remain September 1. (FE3)

**Response:** Please see the response to Comment E-3 in Section IV of this document on the same previously submitted comment.

## **F. Electric Power Entities**

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### **F-1. Comment: *RPS Adjustment***

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~~.

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 MRR's contract-based framework 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.
- (JU1)

**Response:** The comment by Joint Utilities pertains to the RPS Adjustment provisions in the Cap-and-Trade Regulation and is addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**Comment: *Retain REC Serial Number Reporting and Verification***

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.  
(JU1)

**Response:** Please see response to comment F-2 in Section IV, which address the 45-day comments for this rule making.

**Comment:** 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. (PWX2)

**Response:** Staff appreciates support for the change.

## **F-2. Multiple Comments: *REC Serial Numbers and Direct Delivery***

A Simple Date Change is Needed For Reporting RECs. The MRR requires reporting information with respect to RECs, including REC serial numbers, by February 1<sup>st</sup>. However, this information is not fully available by February 1<sup>st</sup>, and in practice is normally provided with the later June 1<sup>st</sup> reporting (though the MRR requires the information on February 1<sup>st</sup>). This could be solved by simply removing the REC requirement from the prior registration section and placing it in more appropriate sections of the regulations, as follows:

*95111(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.

*(1) Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

~~(M) Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:~~

- ~~1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as Legal Disclaimer: Unofficial electronic version of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. The official legal edition is available at the OAL website: <http://www.oal.ca.gov/CCR.htm> California Air Resources Board 111 February 2015 whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.~~
- ~~2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.~~
- ~~3. 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.~~

(4) Additional Information for Specified Sources. For each claim to a specified source of electricity, the electricity importer must indicate whether one or more of the following descriptions applies, and provide information as appropriate for the description:

(F) Deliveries from sources generating associated (including) Renewable Energy Credits (RECs): report the total number, vintage years and months, and serial numbers of all RECs, and whether or not the RECs have been placed in a retirement subaccount.

(5) Additional Information for RPS Adjustment Sources:

(A) RECs associated with electricity procured from 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.

(B) RECs associated with electricity procured from 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.

(C)(5) Substitute electricity. Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section. (SMUD3)

**Comment:** The ARB Should Enforce the REC Serial Number Reporting Requirement. The proposed classification of REC serial number reporting as a nonconformance 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. (TID3)

**Response:** Please see response to comment F-2 in Section IV, which addresses similar comments made during the 45-day comment period for this rulemaking.

### **F-3. Multiple Comments: *Lesser of Analysis Exemptions in §95111(b)(2)(E)(1)***

**Comment:** 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.<sup>7</sup> 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. (CAISO2)

<sup>7</sup> See proposed changes to mandatory reporting regulation at CCR Section 95111 (b)(2)(E).

**Comment:** 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.*

1. ~~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 399.16(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; (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 1<sup>st</sup> verification statement deadline. (LADWP3)

**Comment:** Lesser of Analysis" [MRR section 95111(b)(2)(E)]

LADWP remains concerned about the proposal to remove exemptions from the requirement to report specified imports of zero emission electricity based on the "Sum of Lesser of MWh" equation.

- LADWP believes it is not feasible to apply the "Sum of Lesser of MWh" equation to electricity from the Energy Imbalance Market (EIM) since EIM electricity is produced by multiple generating units (i.e. system power).
- By removing the exemptions for grandfathered RPS resources and dynamically tagged deliveries, the "Sum of Lesser of MWh" equation will be applied to more sources of imported electricity . LADWP sees the following

issues with this:

- i. Increased risk of calculation error. A number of RPS eligible generating facilities that supply California are located in a different time zone. In order to apply the "Sum of Lesser of MWh" equation, either the meter or three-Tag data needs to be shifted so that they both reflect the same time zone. Adjusting for Daylight Savings Time changes can be tricky. These adjustments are time consuming for both the reporter and the verifier.
- ii. Decreased accuracy of the reported data. The "Sum of Lesser of MWh" equation under-reports the true amount of zero emission electricity produced and delivered by not accounting for over-generation , fractional MWh or true-ups between the actual amount generated and delivered. The "Sum of Lesser of MWh" equation may result in over-reporting unspecified imports by assuming substitute electricity where none exists.

Below are examples to illustrate situations where the "Sum of Lesser of MWh" equation will not reflect the true value.

Example	Result of "Sum of Lesser of MWh" equation
A zero emission generating facility produces more MWh during the hour than is shown on three-Tag (aka "over-generation") .	Under-reports the MWh of zero emission energy purchased by selecting the lesser of the hourly e-Tag or meter values. The surplus zero emission electricity produced is ignored.
Meter data includes fractional MWh.	Under-reports the MWh of zero emission energy purchased by selecting the lesser of the hourly e-Tag or meter values . E-Tags show only whole MWh so any fractional MWh would be lost. If fractional generation is not accounted for , the difference between the specified import and MWh actually purchased can be significant over the course of the year.
True-up adjustments if more electricity was produced in a previous hour than was delivered .	Under-reports the MWh of zero emission energy purchased by selecting the lesser of the hourly e-Tag or meter values. Applying fixed% share to hourly meter data will not reflect instances where electricity is delivered to make up for previous under-delivery.

Example	Result of "Sum of Lesser of MWh" equation
Substitute electricity is not provided for generation within the same Balancing Authority Area . For generating facilities physically located outside of California but within a California Balancing Authority Area, the meter value is the correct value. Any difference between thee-Tag value and the meter value is not made up with substitute electricity.	Over-reports the amount of unspecified electricity (i.e. "phantom" emissions) . The "Sum of Lesser of MWh" equation assumes that any difference between the scheduled MWh and the metered MWh is made up with substitute electricity which is reported as unspecified. However, there is no unspecified make-up electricity within a California Balancing Authority Area since all California generation and imports are accounted for.

LADWP recommends the following:

- Limit application of the "Sum of Lesser of MWh" equation to only fixed schedules and situations where substitute electricity may be provided. Do not apply it to zero emission generating facilities that are tied to a California Balancing Authority since there is no substitute electricity in that case.
- Add the option to use the settlement or invoice amount in cases where applying the "Sum of Lesser of MWh" equation would not produce accurate results. (LADWP3)

**Comment:** 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 SCPPA 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,”<sup>7</sup> and agree that there are several factors 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.

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<sup>7</sup> As provided on page 4 of the [notice](#) of availability and summary of changes for the Mandatory Reporting of Greenhouse Gas Emissions. (SCPPA2)

**Comment:** A Change That Needlessly Increases the Complexity of Reporting. The proposed change to 95111(b)(2)(E)(1) should not be adopted by the Board. Staff-proposed changes would eliminate certain exclusions to the “lesser of” analysis. This Staff-proposed change should be rejected for dynamically tagged power deliveries and the EIM. Having these resources perform a “lesser of” analysis adds reporting complexity unnecessarily at a time when ARB is tightening reporting and verification deadlines. In the case of dynamically tagged power deliveries, it creates incompatibility with the RPS reporting requirements by potentially relying on less accurate E-tag information. With respect to the EIM, it creates unnecessary complication since ARB is not using the tagged resources to determine emissions.

Dynamically tagged resources are outside the CAISO’s balancing authority, but the resource is dispatched by the CAISO to meet CAISO load; it is identical to a renewable resource within California. The “lesser of” analysis is an hour-by-hour comparison of what was tagged compared to what was metered, but the meter data is the most accurate. As such, if meter data can be used, it is ineffective to have to compare it to the less accurate tagged amount. Tagging is a North American Electric Reliability Corporation (NERC) requirement when transferring power between balancing

authorities that does not require the same degree of accuracy as the meter data, as acknowledged by ARB Staff.<sup>1</sup>

<sup>1</sup> ARB Staff, Initial Statement of Reasons for MRR, page 44.

For EIM, it is unclear why the proposed increase in accuracy is needed since “deemed delivered” resources are not assumed to be the resources dispatched. Further, this approach would complicate the operation of the EIM market by making the GHG cost uncertain while leaving the EIM Total California dispatch emissions unchanged.

**SDG&E Recommendation:** The Board should continue the exemption to the “lesser of” analysis for dynamically tagged resources and EIM resources in 95111(b)(2)(E)(1). (SDG&E proposed change is double underscored)

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 399.16(d) or California Code of Regulations, Title 20 Section 3202(a)(2)(A); (12) dynamically tagged power deliveries; (23) untagged power deliveries, including EIM imports; ...

SDG&E looks forward to continued dialogue with ARB, and we thank you for the opportunity to comment on ARB’s proposed amendments to Mandatory Reporting Regulation. Please contact me if you have any questions or concerns about these comments. (SDGE2)

**Comment:** ARB Should Restore the Grandfathered Contract Exclusion to the “Lesser Of” Analysis. SMUD continues to support restoration of the exclusions in the requirement in section 95111(b)(2)(E)(1) to prepare a “lesser of” analysis for imported power. In the Proposed Amendments, grandfathered RPS contracts and dynamically scheduled renewable imports have been removed from the list of exclusions from the “lesser of” analysis in section 95111(b)(2)(E)(1). Originally, these contracts were excluded because the “lesser of” analysis for qualifying “bucket 1” products in the RPS did not apply to these contracts. Requiring the analysis creates inconsistency between the two programs. It also is problematic because the meter data is not under SMUD’s control and may not be owed SMUD under these contracts. ARB should restore this exclusion for the limited number of grandfathered contracts. (SMUD3)

**Comment:** The ARB Should Not Amend Section 95111(b)(2)(E) to Impose a Meter Data Comparison Obligation on Grandfathered Resources. The proposed revisions to the MRR would remove grandfathered resources from the list of sources that are not subject to a lesser-of meter data comparison. 2013 MRR Rulemaking documents do not explicitly address the rationale for the original exclusion of the grandfathered resources, but it is our understanding from discussions with ARB staff at the time that the exclusion was intended to create consistency with the RPS program.



TID currently meets the majority of its RPS obligations through the Tuolumne Wind Project (“TWP”), which is an owned, grandfathered resource. TWP is both directly delivered and firmed and shaped. We are concerned that a lesser of analysis would create an inconsistency with the RPS verification requirements for this resource. CEC Regulations only require a meter data/e-tag comparison for PCC-1 resources (i.e., resources that were procured after 2010). Grandfathered resources are not subject to a meter data/e-tag comparison.<sup>1</sup> We are concerned that by requiring a meter data comparison, there will be inconsistencies in the amount of renewable generation that counts towards our RPS obligation and the amount of renewable generation that is counted as unspecified in the MRR. We are also concerned that it is not clear in the explicit language of the MRR that the RPS adjustment can be claimed when there is a reclassification of a specified import to an unspecified import. We therefore request that the ARB retain the exclusion of grandfathered resources from the meter data comparison requirement.

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<sup>1</sup> See description of grandfathered resources at 20 Cal. Code Reg. Sec 3202(a); See also, CEC Draft RPS Verification Methodology Report, pp. 17-20, available at: [http://docketpublic.energy.ca.gov/PublicDocuments/11-RPS-01/TN215142\\_20170103T150023\\_RPS\\_Verification\\_Method\\_Report.pdf](http://docketpublic.energy.ca.gov/PublicDocuments/11-RPS-01/TN215142_20170103T150023_RPS_Verification_Method_Report.pdf); See also, RPS Eligibility Guidebook Section VI, pp. 64-67, which does not set forth an e-tag requirement for grandfathered resources, available at: <http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf>.

(TID3)

**Comment:** CARB should request CAISO to adjust energy deemed delivered to California to reflect metered data. CARB staff have proposed elimination of the lesser of analysis requirement for electricity imported via the EIM. We understand that this is because the EIM export allocation is not adjusted to reflect actual metered data, but instead reflects the resource’s forecast availability going into the hour. Rather than require EIM PRSC’s to perform a ‘lesser-of’ analyses for energy deemed delivered to California, WPTF reiterates its request that CARB explore with CAISO whether it would be possible for the EIM allocations to reflect metered data. (WPTF2)

**Response:** We thank CAISO for its support. For the other comments, please see response to comment F-4 in Section IV, which addresses similar comments submitted during the 45-day comment period for this rulemaking.

#### **F-4. Multiple Comments: *First POR, Source of Generation 95111(a)(2)***

**Comment:** Section 95111(a)(2) – General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters; Delivered Electricity. PG&E appreciates ARB’s modification to not require reporting of generation source. As noted by ARB, requiring imported power to be disaggregated by generation source would have been unnecessarily complicated and of limited usefulness. (PGE3)

**Comment:** 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 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)

**Comment:** 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. (SCPPA2)

**Response:** We thank PG&E and Powerex for their support, and we look forward to future input from SCPPA.

#### **F-5. Comment: *Sales into CAISO under §95111(a)(12)***

**Comment:** Further Clarification is Needed on Reporting Sales into the CAISO. SMUD supports additional clarification of the requirements for reporting sales into the CAISO. The Proposed Amendments include a new provision that entities must report sales into the CAISO that do not serve "native load". SMUD simply notes that subpart (B) still states that "This requirement does not apply to EDUs that have had all of their directly allocated allowances allocated for the data year placed in their limited use holding account pursuant to section 95892(b)(2) of the Cap-and Trade Regulation." This statement is ambiguous, as it is unclear whether it applies only to the subpart (A) that is in the current regulations, or to all of the subparts in the section.

There is still a blanket prohibition of using allowances and allowance value for sales into the CAISO in the Cap and Trade Regulations, and the exemption in subpart (B) appears to be in conflict with that requirement because allowance value from sales of free allowances placed in the limited use holding account could still be used to

purchase allowances to cover sales into the CAISO. Thus, SMUD suggests that the MRR should be modified to remove the exemption in paragraph § 95111(a)(12)(B), thus requiring reporting of all sales into the CAISO, regardless of whether an EDU directs all of their free allowances into their limited use holding account. (SMUD3)

**Response:** Staff addressed these concerns in the response to comment F-7 in Section IV of this document, which addressed 45-day comments.

#### ***F-6. Multiple Comments: Accounting For Imported Electricity Emissions from EIM and Addressing Emissions Leakage***

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.

In comments submitted in this rulemaking last year, the ISO explained the operation of the western Energy Imbalance Market (EIM) and how the ISO's market optimization attributes EIM transfers to serve California load to EIM participating resources. The ISO also explained how ARB's regulations apply resource-specific emission rates for EIM participating resources dispatched through the ISO's market optimization. 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.<sup>2</sup> The ISO is actively exploring this approach with stakeholders and plans to complete its conceptual design during the first quarter of 2017.<sup>3</sup> 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.

<sup>2</sup> 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.

<sup>3</sup> More information on the ISO's stakeholder initiative is available on the ISO's website: <http://www.caiso.com/informed/Pages/StakeholderProcesses/RegionalIntegrationEIMGreenhouseGasCompliance.aspx>

\* \* \*

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.<sup>4</sup> 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.

<sup>4</sup> See proposed changes to cap-and-trade regulation in ARB's 15 Day Notices at 17 California Code of Regulations Sections 95852.

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 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 under-account emissions associated with EIM transfers to serve California load.<sup>5</sup> 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.

<sup>5</sup> 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>

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.

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.<sup>6</sup> 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 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. As part of its next 15 Day Notices in this rulemaking, ARB should acknowledge this effort and develop a mechanism to apply the results of the ISO's enhanced market optimization in its cap-and-trade and mandatory reporting regulations.

\* \* \*

VI. Conclusion. 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. The ISO supports ARB's proposed bridging solution to account, on an interim basis, for emissions from EIM transfers serving California load. However, ARB must make additional changes to the material posted as part of its 15 Day Notices. ARB should acknowledge that the bridging solution is interim until the ISO implements enhancements to its market optimization that more accurately accounts for emissions from EIM transfers to serve California load. ARB also should eliminate its proposed changes that exclude EIM transactions from the resource shuffling safe harbor. This language creates uncertainty for entities subject to ARB's regulation and it is inconsistent with other language in ARB's regulation relating to resource shuffling. ARB should also 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, and ARB can obtain information from the ISO to verify data reported by emitting entities through other methods.

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<sup>6</sup> 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-RegionalIntegration-EIMGreenhouseGasCompliance.pdf>

(CAISO2)

**Comment:** 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. (CMUA2)

**Comment:** Since its inception in 2014, the EIM has produced substantial economic and environmental benefits for customers both inside and outside of California. 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. The geographic diversity of the multi-state EIM also reduces the curtailment of renewable resources by having access to more resources capable of being displaced by carbon-free generation in real-time. The California Independent System Operator ("ISO") has estimated EIM benefits to customers totaling \$114.35 million from November 2014 through September 2016.<sup>1</sup> In terms of environmental benefits, the ISO calculates in the first three quarters of 2016 that EIM dispatch reduced GHG emissions in the footprint by 143,695 metric tons.<sup>2</sup> These benefits are expected to grow in magnitude with the recent joining of Arizona Public Service and Puget Sound Energy in October 2016 and as the EIM continues to expand with, Portland General Electric (2017), Idaho Power (2018), and Seattle City Light (2019) and beyond.

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<sup>1</sup> ISO EIM Benefits Report Q2 2016, [http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ3\\_2016.pdf](http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ3_2016.pdf)

<sup>2</sup> *Id.*

Given the realized and expected future benefits, the EIM Entities have a considerable stake in ensuring that the EIM continues to operate in such a manner that enables these important benefits to continue. The following comments are provided in this context.

B. Comments: The EIM Entities Accept ARB's Proposed "Bridge" Solution. 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.

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. (EIM-ENT1)

**Comment:** PacifiCorp accepts ARB's interim proposal. 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.

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. (PacifiCorp2)

**Comment:** Section 95111(h) – Reporting requirements for the California Independent System Operator (CAISO) Energy Imbalance Market (EIM). As noted in PG&E's comments on the Cap-and-Trade amendment 15-day text, PG&E generally supports ARB's interim approach to account for and recognize secondary emissions in the EIM.



PG&E views the removal of revisions to this section as consistent with implementing the solution as described in the Cap-and-Trade amendments. (PG&E2)

**Comment:** As discussed in detail in Powerex’s previous comments,<sup>1</sup> 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*.

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<sup>1</sup> 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-ViZVPFujWW9WigFk.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>.

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.<sup>2</sup> 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.

<sup>2</sup> 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>

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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.

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 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. (PWX2)

**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. 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.

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, ARB's 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.

<sup>8</sup> 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>

(SCPPA2)

**Comment:** WPTF supports CARB's proposed interim solution to address GHG Accounting concerns in the EIM. Specifically, we support the proposal for CARB to calculate the quantity of "EIM Outstanding Emissions", relative to total emissions resulting from the dispatch and assignment of energy imports by the EIM algorithm, using the default emission rate. However, we have several concerns with how this approach is reflected in the MRR.

Section 95111 (h)(1)(B) should be made clearer. *Our first concern is with respect to organization and clarity. Staff's proposed approach in section 95111 (h)(1)(B) includes reporting requirements for EIM Participating Resource Scheduling Coordinators (PRSCs), the CAISO itself and steps that CARB staff will take to calculate the quantity of EIM outstanding emissions. However, these requirements and steps are not clearly delineated. Further, while some of the information required to be reported by CAISO is necessary for the calculation of outstanding EIM emissions, other information, such as state wide EIM imports and exports appears geared toward improving transparency or to enable verification of total EIM imports reported by PRSCs.*

To make this section more understandable, WPTF recommends that CARB clearly separate the reporting requirements for reporting by PRSCs and the CAISO, and delineate the steps for calculation of outstanding emissions sequentially. For instance, CARB's calculation of outstanding emissions should follow the reporting by PRSCs of EIM imports and emissions, and reporting by the CAISO of EIM emissions using the default emission rate. We also request how information reported by CAISO on state-wide EIM imports and exports will be used.

Reporting requirements should be restricted to PRSCs that are deemed to have delivered EIM energy to serve California. *WPTF's understanding is that only EIM PRSCs that are deemed by the EIM algorithm to have delivered energy to serve*

*California load are required to report under the MRR. However, the language of 95111 (h)(1)(C) applies to all EIM PRSCs. WPTF therefore recommends that CARB modify this language to limit its applicability to PRSCs that are deemed to have delivered EIM energy to serve California load.*

References to 5 minute intervals should be more precise. *In several places in 95111(H), the regulation uses the phrase 'based on each 5-minute interval'. We believe this is intended to mean that the annual reports should be an aggregation of data across all 5 minutes in the year, and request that CARB amend the regulation to clarify this.* (WPTF2)

**Comment:** Third, SDG&E urges ARB to use the CAISO's full "counterfactual" approach to assess the "impact to the atmosphere." The counterfactual calculates the net GHG increases or reductions in the western U.S. as a result of the operation EIM market in all hours, not just the hours California is importing power. This calculation is a much truer estimation of the "impact to the atmosphere" of the EIM market than ARB Staff's approach that cherry-picks impacts to the atmosphere only in hours California is a net importer of power. In Attachment B to the MRR, the ARB Staff incorrectly concludes that emission reductions from power plants outside the State caused by the operation of the EIM market cannot be counted. But the fact that ARB allows offsets from anywhere in the United States and also allows reductions in the province of Quebec, Canada and potentially Ontario, Canada to count toward reductions in compliance obligations in California shows that the reductions in emissions outside of California as a result of the operation of the EIM market, as calculated in the CAISO's counterfactual, can in fact be counted if ARB chooses to do so. (SDGE2)

**Response:** Most of the comments related to accounting of GHG emissions associated with imported electricity under EIM are addressed in Comment F-6 in Section IV of this document. The response to that comment also addresses ARB's determination of the appropriateness of using the default emission factor to determine underreported emissions under EIM and ARB's accounting rules as they pertain to accounting for imported and exporter power.

The commenters bring up a couple additional issues in the comments submitted under the first 15-day amendments package which staff will address here. First, to address the comments regarding a timeline for moving from the bridge solution to an updated EIM accounting within the CAISO model, ARB will participate in the CAISO stakeholder process to develop the two-pass solution and follow the progress on tariff change approvals through FERC. Once CAISO has an approved updated EIM design through FERC, ARB will initiate a rulemaking to remove the bridge solution.

Second, 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 MRR 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 B to the 15-day amendment package, please see the response to Comment F-9 in this section of the document below.

In regards to WTPF's comments, the reporting requirements are only limited to Participating Resource Scheduling Coordinators with electricity that is deemed delivered to serve California load. If an entity has not been deemed to serve California load though the EIM model, it does not have to report to ARB. Additionally, ARB has made clarifications to the text as WPTF describes and it now reads "based on the results of each 5-minute interval."

#### **F-7. Comment: *Methods for Calculating EIM Emissions***

There are several more accurate methods [than the ARB outstanding emissions proposal] to calculating GHG emissions for EIM electricity as described below.

First, ARB could require EIM sellers to report emissions as asset-controlling suppliers (ACSS) and allow renewable power in other jurisdictions to deliver as null power, electricity stripped of its renewable attributes. The development of the ACS designation was specifically designed to account for entities with renewable resources selling them to California and back-filling with fossil generation. It is not clear why EIM sellers with renewable resources should be treated differently than sellers in the day-ahead market with renewable resources. Given that ARB Staff is explicitly accounting for the EIM power as unspecified power, the ACS designation seems appropriate. Likewise, entities with renewable power in other jurisdictions may assign the renewable attribute to meet in-state RPS requirements, but like to sell the null power to California. ARB could allow renewable resources in the EIM market to include a GHG compliance cost and treat their power as unspecified since ARB is proposing to treat it as unspecified anyway. This change would not only allow more electricity to be delivered to California, but would make the "deemed delivered" GHG emissions closer to the proposed ARB assignment of unspecified to the power, minimizing EIM Outstanding Emissions.

A second, more accurate approach to calculating the EIM outstanding emissions would be to use the emissions of the CAISO's "two pass solution" to determine the specified resources dispatched to serve California based on the CAISO's optimization model. The CAISO two pass solution first optimizes the EIM market outside California and then includes California. This two pass solution determines which resources are dispatched to serve California. EIM outstanding emissions would use the emissions of the resources dispatched to California from the two-pass solution and then subtract known GHG emissions associated with EIM deemed delivered imports. Since the CAISO two pass solution approach correctly identifies resources dispatched to serve California , it

captures what ARB intends to capture rather than using the unspecified default emissions factor. While the CAISO cannot complete the two passes within the 5 minute increment, it can produce the second pass solution presently. ARB has not explained why it has rejected the more accurate CAISO two pass solution to calculate EIM total emissions instead of using the default emissions factor applied to EIM “deemed delivered” resources.

\* \* \*

SDG&E Recommendation: SDG&E requests the Board reject the Staff-proposed changes to the MRR regarding EIM in Section 95111(h) regarding “EIM outstanding emissions” and replace it with the following: (SDG&E proposed change is double underscored).

(h) Reporting requirements for Imported Electricity in the Energy Imbalance Market (EIM) the California Independent System Operator (CAISO). Annually, CAISO will calculate, report, and cause to be verified, the information listed here:

(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, CAISO will calculate the following:

(A) “Remaining EIM Outstanding emissions” equals “Total California EIM dispatch eEmissions” less “Deemed Delivered EIM Emissions” —emissions associated with electricity imported by EIM Participating Resource Scheduling Coordinators deemed delivered to California by the EIM optimization model.  
Where “Total California EIM dispatch eEmissions” equals the amount of emissions calculated by CAISO pursuant to section 95111(h)(1)(B) EIM transfers (Mwh) identified by CAISO to serve California load multiplied by the unspecified emission factor;

(B) Calculating Total California EIM dispatch Emissions. Annually, based on each 5-minute interval, CAISO must calculate, report and cause to be verified, the CO2 equivalent mass emissions associated with imported electricity in EIM using the counterfactual based on the two pass solution for each 5-minute interval. following equation:

$$\underline{\underline{CO_2e = MWh \times E_{Funs} \times TL}}$$

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;

E<sub>Funs</sub> = 0.428 MT of CO2e/MWh

TL = 1.02 (transmission loss factor);

(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:

- (A) Annual sum of the “remaining emissions” calculated in section 95111(h)(1); 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) Names of entities meeting California imbalances from EIM transfers and annual quantity of purchased MWh for each entity based on 5 minute interval data; 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 dispatch eEmissions, 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.

3. The data provided in this section 95111(h)(2) must be verified per section 95103(f). (SDGE2)

**Response:** ARB declines to make the changes requested by the commenter. In the second 15-day amendment package, staff removed CAISO as a reporting entity under MRR and instead will receive the necessary information from CAISO through an annual subpoena process. Therefore, the commenter’s proposed revisions that assume CAISO will be a reporting entity are now irrelevant.

In addition, ARB cannot determine—as commenter proposes—EIM emissions based on a counterfactual using the two-pass solution because the CAISO’s two-pass market optimization has not been finalized and, therefore, the ultimate emissions impacts are unknown at this time.

The commenter’s suggested alternate EIM compliance obligation proposal is also not feasible. This is most apparent in the commenter’s proposed revision to section 95111(h)(1)(B). It is not possible to retroactively calculate the compliance obligation that would occur under the two-pass solution because the compliance obligation that would result from the implementation of that solution will be assigned with a revised algorithm that results in different dispatch. In some intervals, a retroactive calculation to determine the

resources that are selected to serve California load under the two-pass revision (as suggested in the commenter's proposal) would not be capable of identifying sufficient bids to serve California load. The bridge solution proposed by ARB is intended to address accounting issues with EIM in the interim, while the two-pass solution is being developed, considered by CAISO's board and FERC. For more information please see the response to comment F-6 in Section IV of this document.

In regards to the comment that ARB should require EIM entities to report as asset controlling suppliers (ACSs), ARB has determined not to pursue this option for its interim solution because it would require substantially more data to be reported by EIM entities including data for every resource in the EIM entity's footprint. The information would also need to be verified in order for ARB to calculate an ACS emission factor for the entity's entire footprint. Because CAISO is working on a long term solution to correctly identify which specific resources serve California load, ARB felt this level of additional reporting requirements for what is likely a 2-3 year bridge solution was excessive. It is outside of ARB's purview to make changes to the EIM model and how it deems electricity delivered to California. CAISO is working with ARB and stakeholders to make changes to its model to ensure that it correctly accounts for EIM emissions.

#### **F-8. Multiple Comments: *ARB's Analysis of EIM***

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.

Second, 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. The proposed unspecified resource solution would have to be reevaluated continually to track the system average emission calculation.

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.

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. (CMUA2)

**Comment:** ARB's EIM Analysis is Misleading. 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. (EIM-ENT1)

**Comment:** ARB's EIM Analysis should clearly state that it is not an environmental assessment of the EIM. 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 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. (PACCORP1)

**Comment:** Attachment B to the MRR explains that ARB Staff does not believe the EIM, as currently constituted, is providing all of the data necessary to support full accounting of GHG emissions emitted to the atmosphere. Specifically, the EIM identifies the least-cost resource as being "deemed delivered" to serve California load. But according to ARB Staff, though MRR accurately tracks the electricity imports identified by CAISO's current EIM system, the tracking is incorrect because the "deemed delivered" resources may not be the ones incrementally dispatched to serve California load. The new reporting approach proposed by ARB Staff for EIM imported electricity requires EIM participating resource scheduling coordinators to continue reporting as they currently do under MRR. However, ARB Staff will calculate the amount of emissions ("EIM outstanding emissions") emitted to the atmosphere in excess of the GHG emissions of the resources identified by the CAISO as delivering power to California. The EIM outstanding emissions will be calculated 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 EIM "deemed delivered" imports.

This approach treats all EIM-reported power transferred to California as unspecified power while requiring importers to treat the power as specified imports under the MRR. This approach is confusing since it treats EIM-transferred power in opposite ways at the same time. (SDGE)

**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 B, 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.<sup>17</sup>

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. By capturing GHG emissions in the revised GHG accounting framework, ARB is comfortable with reinstating the short term shuffling exemption for EIM imports. These changes provide EIM market participants greater certainty on the interaction between MRR and the Cap-and-Trade Program’s GHG accounting framework and the EIM.

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 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 ARB’s EIM analysis is either small or may not increase as new EIM entities 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.

#### **F-9. Multiple Comments: *CAISO as Reporting Entity***

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.<sup>11</sup> ARB has not justified the need for this change. Other, less burdensome, methods

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<sup>17</sup> 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>

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.<sup>12</sup> 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.<sup>13</sup>

ARB's regulations must be reasonably calculated to meet its statutory directive.<sup>14</sup> There must be substantial evidence supporting ARB's determination that the regulation is reasonably necessary to effect AB 32.<sup>15</sup> Earlier in this rulemaking, ARB asserted that it needed additional data from the ISO to ensure an accounting of greenhouse gas emissions.<sup>16</sup> However, ARB already receives all of the data associated with EIM transfers to serve California load from EIM participating resource scheduling coordinators.<sup>17</sup> 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.

<sup>11</sup> See proposed changes to 17 CCR Section 95111(h).

<sup>12</sup> California Health and Safety Code Section 38530(b)(1).

<sup>13</sup> California Government Code Section 11342 requires ARB's proposed regulations to be consistent with its authority under AB 32.

<sup>14</sup> California Government Code Sections 11342 and 11349.

<sup>15</sup> *Id.* at Section 11350.

<sup>16</sup> ARB Staff Report: Initial Statement of Reasons at 9.  
<https://www.arb.ca.gov/regact/2016/ghg2016/ghgisor.pdf>

<sup>17</sup> 17 CCR Section 95111.

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 physical path with the point of receipt located outside of California and the point of delivery located inside California.<sup>18</sup> 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.

<sup>18</sup> 17 CCR Section 95802(a)(122).

In fact, ARB has already issued a standing subpoena to the ISO for EIM transaction data.<sup>19</sup> 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.<sup>20</sup> 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 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.<sup>21</sup>

<sup>19</sup> <http://www.caiso.com/Documents/2015-04-01CaliforniaAirResourcesBoardSubpoena.PDF>

<sup>20</sup> See proposed changes to mandatory reporting regulation at 17CCR Section 95111 (h).

<sup>21</sup> 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.

(CAISO2)

**Comment:** CAISO should not be subject to third party verification. Proposed section 95111 (h)(3) of the regulation suggests that the reports submitted by the CAISO in accordance with paragraphs 95111(h)(1) and (2) are subject to third-party verification. WPTF opposes this provision for two reasons. First, the CAISO is not a reporting entity under the MRR. Second, CAISOs reports to CARB will be based on the results of the EIM optimization algorithm, which will also determine the dispatch of EIM resources and energy that is deemed delivered to serve California load. To require third party

verification of CAISO reports suggests that the market results of the EIM algorithm may be questioned by verifiers and CARB staff. This is inappropriate. WPTF recommends that CARB delete the requirement that CAISO reports be subject to third-party verification. Instead, CARB staff should consult with CAISO to better understand the quality control and quality assurance procedures that CAISO has in place to ensure that veracity of the EIM algorithm's output.

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EIM Exports out of California cannot be reported by PRSC. *Paragraph 95111 (h)(2) require CAISO to report total annual EIM exports from California for each PRSC and for the CAISO. Our understanding is that the EIM algorithm does not attribute EIM transfers out of California to specific resources or PRSC. If this is correct, it would not be possible for CAISO to report this information to CARB. The reference to PRSCs in this paragraph should be deleted.* (WPTF2)

**Response:** ARB withdrew its proposal to make CAISO a reporting entity and require third-party verification in the second 15-day modifications; therefore, these comments have been addressed. This decision was premised in significant part on CAISO's commitments to continued data-sharing (including via subpoena) with ARB, and an ongoing close working relationship. ARB appreciates CAISO's efforts work with ARB staff to make reporting entity status unnecessary at this time.

#### **F-10. Multiple Comments: *EIM Safe Harbor***

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.<sup>8</sup>

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."<sup>9</sup> 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 safe harbor from the prohibition against resource shuffling for ISO real-time market

transactions.<sup>10</sup> 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.

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<sup>8</sup> See proposed changes to cap-and-trade regulation at 17 CRR Section 95852(2)(a)(10).

<sup>9</sup> 17 CRR Section 95802(a)(336).

<sup>10</sup> California Government Code Section 11349 requires that proposed regulations do not conflict with or are not contradictory to existing law.

(CAISO2)

**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. (CMUA2)

**Comment:** ARB Should Not Exclude EIM from the Resource Shuffling Safe Harbor. 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. (EIM-ENT1)

**Comment:** ARB should not exclude EIM from the resource shuffling safe harbor. 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 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. (PACCORP1)

**Comment:** Resource Shuffling in the EIM. 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.”<sup>3</sup> 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.

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<sup>3</sup> 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.

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 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.<sup>4</sup>

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. (PWX2)

**Response:** This issue is out of scope for this MRR rulemaking as it pertains to provisions in the Cap-and-Trade Regulation. This issue will be addressed in the 2017 FSOR for the Cap-and-Trade Regulation.

#### **F-11. Comment: *Public Input Process***

Process Concerns. As expressed in prior public comments and letters, SCPA 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.

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.

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. (SCPPA2)

**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. Moreover, ARB staff met frequently throughout this process with representatives from many stakeholders, including commenter. As such, ARB has fully complied with the APA in this rulemaking.

#### **F-12. Comment: *Multiple Questions Raised by ORA***

ORA appreciates this opportunity to comment on the proposed 15-day modifications on amendments to the regulation for the mandatory reporting of greenhouse gas (GHG) emissions. ORA provides the following comments intended to support the alignment of ARB's proposed amendments to the regulations with the state's current and future policies for reducing GHG emissions. ORA focuses on developing strategies that minimize the cost impact on California's ratepayers, while maximizing the benefits from their investments in current and future programs to achieve the state's GHG reduction goals. 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.

## 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 CO<sub>2</sub>e 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)."<sup>2</sup>

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 CAISO.<sup>3</sup> Staff stated that "this data can then be used to appropriately determine compliance obligations in the Cap-and-Trade Regulation."<sup>4</sup> 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 regulations<sup>5</sup> 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."<sup>6</sup>

<sup>2</sup> 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>

<sup>3</sup> 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>

<sup>4</sup> 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>

<sup>5</sup> 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>.

<sup>6</sup> 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>

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:<sup>7</sup>

(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 CO<sub>2</sub> equivalent mass emissions associated with imported electricity in EIM using the following equation:

$$CO_{2e} = MWh \times EF_{unsp} \times TL^8$$

(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.

<sup>7</sup> 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>.

<sup>8</sup> Where: CO<sub>2</sub>e = CO<sub>2</sub> equivalent mass emissions from Total California EIM electricity (MT of CO<sub>2</sub>e); MWh = Megawatt-hours of EIM imports identified by CAISO to serve California load.  $EF_{unsp} = 0.428$  MT of CO<sub>2</sub>e/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>.

(2) Annually, CAISO will report, and cause to be verified, the following information:<sup>9</sup>

- (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.

<sup>9</sup> 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>

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?

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.<sup>10</sup> 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.<sup>11</sup> In this situation, after paying a renewable premium for Renewable Energy Credits (RECs) in compliance with the RPS program, any importing 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.



Lastly, ORA requests that ARB Staff hold a public workshop or meeting to discuss its proposed bridge solution to 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.

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<sup>10</sup> 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.”

<sup>11</sup> Refer to CEC Guidebook, Renewable Portfolio Standard Eligibility, 3<sup>rd</sup> ed., January 2008.  
<http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF>.

(ORA2)

**Response:** Please see response to comments F-6 in Section IV. of this document and F-6 in Section V. of this document. In addition, ARB is providing responses to the 12 questions that ORA poses in this comment. (1) The bridge solution will be in place until FERC approves the new tariff and CAISO is able to implement the two-pass solution, which is expected in the next few years. If ISO finalizes two-pass market optimization, ARB will consider appropriate regulatory changes to align its regulations with such improvements. (2) No, the proposed solution will not impact the compliance obligation of covered entities since the EIM outstanding emissions (emissions underreported by the EIM model's deeming methodology) will be quantified by ARB and unsold allowances will be retired. (3) The CAISO two-pass solution is expected to result in a more accurate accounting of GHG emissions from EIM imports to California. Compliance obligations for EIM emissions assessed by ARB are based on the emission factor for each specified resource deemed as supporting an EIM import and the amount of MWhs imported from that resource. Compliance obligations are assigned to PRSCs whose balancing authorities include the deemed resources. The methods for determining emission factors from these generating resources remains unchanged from existing MRR provisions. CAISO anticipates different resources may be deemed as a result of the two-pass solution. For compliance entities a change in the deemed resources could result in lower or higher compliance obligations for the PRSCs depending on the generating resources deemed by the EIM model to serve California load. (4) Deemed delivered EIM emissions are those emissions associated with electricity imported by EIM Participating Resource Scheduling Coordinators deemed delivered to California by the EIM optimization model. (5) Real-Time Dispatch (RTD) occurs for every 5-minute interval. (6) ARB intends to use the proposed amendments in section 95111(h) to account for EIM outstanding emissions associated with EIM imports to California. ARB will then retire unsold allowances that equal the amount of outstanding EIM emissions to account for emissions leakage and ensure environmental integrity. (7) The intent of the proposed bridge solution is to determine the annual EIM outstanding emissions for California in total, which is based on the sum of emissions and megawatt hours reported by each EIM entity. The sum of information reported by the individual entities will also be provided by CAISO under an annual subpoena. (8) The proposed amendments



in section 95111(h)(2)(B) were removed in the second 15-day changes. (9) The proposed amendments in section 95111(h)(2)(B) were removed in the second 15-day changes. (10) The proposed amendments in section 95111(h)(2)(B) were removed in the second 15-day changes. (11) The intent of the proposed bridge solution is to determine the annual EIM outstanding emissions for California in total. ARB will not be calculating EIM outstanding emissions for each EIM entity. (12) The proposed EIM outstanding emissions amendments would not treat emissions resulting from eligible imports under PCC2 as unaccounted for emissions, because PCC2 imports are expected to be separately reported as distinct imports under MRR, and PCC2 power is not expected to contribute to EIM imports into California.

**F-13. Comment: *Determine Effects on Allowance Supply and Pricing***

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. (SCPPA2)

**Response:** This comment is out of scope for this MRR rulemaking as it addresses provisions in the Cap-and-Trade Regulation. The issues regarding unsold allowances are addressed in the 2017 FSOR for the Cap-and-Trade Regulation.

**F-14. Comment: *Accounting for Energy Transfers from Adjacent States***

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 changes in section 95111 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 MRR rules and practices to properly account for the impact of VEA's balancing energy on California carbon. (VEA2)

**Response:** Please see response to comment F-13 in Section IV. of this document, which addresses these concerns.

## **G. Miscellaneous Comments**

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### **G-1. Comment: *Section 95973(b)***

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.<sup>4</sup> 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.<sup>5</sup> (CALPINE2)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

## **G-2. Comment: *Support of Cap and Trade***

### **SUPPORT FOR CONTINUATION OF THE CURRENT CAP-AND-TRADE PROGRAM**

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. (SCPPA2)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

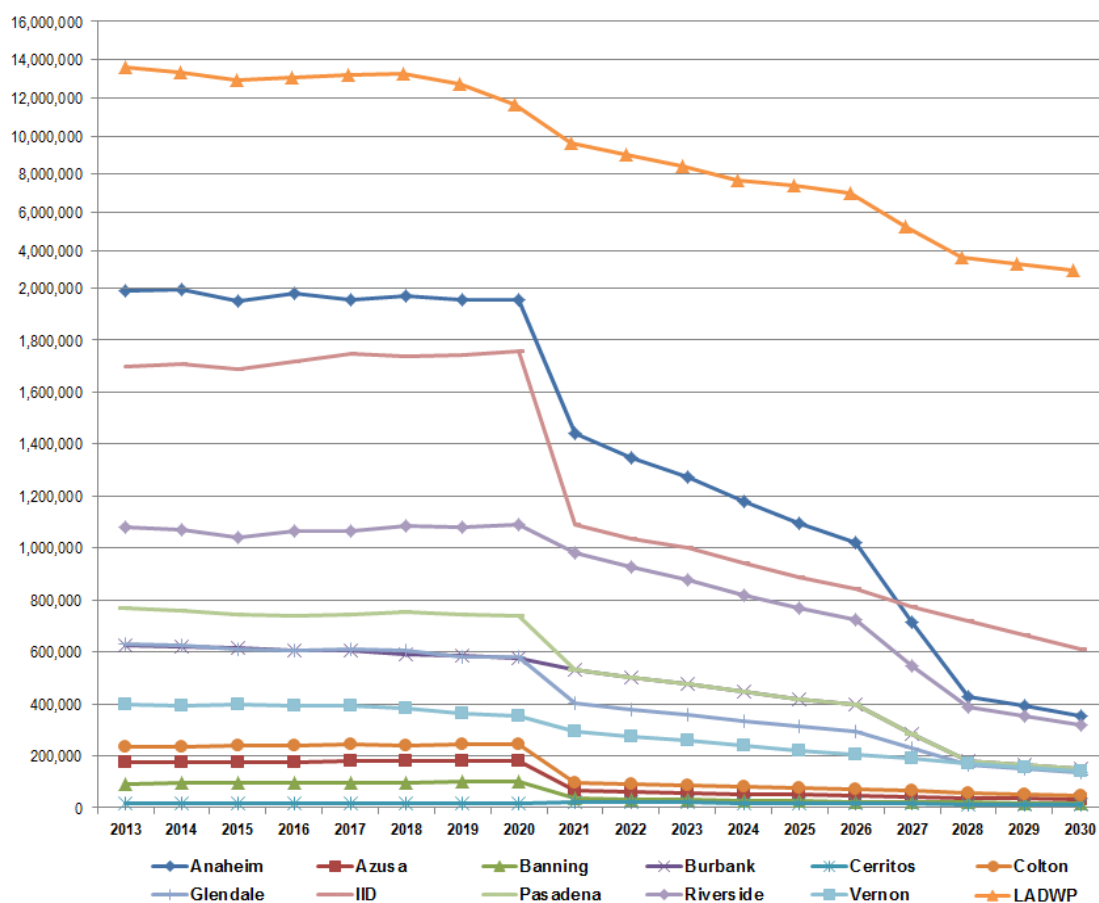
## **G-3. Comment: *EDU Allowance Allocation Methodology***

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.<sup>1</sup> 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.

Figure 1: SCPPA Member Allowances [2013-2030]



<sup>1</sup> 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 —20 21 -20 30 EDU Allowance Allocation Spreadsheetll posted on December 21, 2016.

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 POUs and IOUs 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 POUs and IOUs, and should refrain from pushing POUs 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 POUs 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 POUs to consign allowances to auction. ARB has historically exercised sound reason in its decision to exclude POUs from the requirement to consign allowance allocations to auction, as is required of IOUs; IOUs and POUs are neither structured nor governed the same way. This historic rationale is still valid.

A requirement for POUs 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 POUs more than others. Many POUs 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)<sup>2</sup>:

<sup>2</sup>See pages 342 and 564 of the October 2011 Final Statement of Reasons for the Cap and Trade Regulations

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 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. 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. [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 FSOR<sup>3</sup>, 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.

<sup>3</sup>See pages 578-579 and 580-581 of the October 2011 Final State of Reasons for the Cap-and-Trade Regulations.

**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.<sup>4</sup> 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<sup>ll</sup> use of allowance value; though, any such clarification should not identify specific uses.

<sup>4</sup> See pages 65-66 of the October 2011 Final Statement of Reasons for the Cap-and-Trade Regulations.

**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.

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<sup>5</sup>. 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 staff (in particular, those at the CEC) to identify possible solutions in an expedited manner.

<sup>5</sup>As noted on page 4 of Attachment C: 2021-2030 Allowance Allocation to Electrical Distribution Utilities, released with the Cap-and-Trade regulatory package on December 21, 2016.

Industrial Allocation Shift. SCPPA 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. SCPPA 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.<sup>6</sup>

<sup>6</sup>Ibid.

The inequity cited by staff is not valid for the vast majority of POU. The generic language neglects to discuss the impacts on EDUs that serve significant industrial loads. SCPA 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 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 policyll 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 POU that has not been evaluated by ARB staff. Neither POU 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.

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 —nullll power. SCPPA believes that a workable solution exists and has collaborated with the Joint Utility Group (—JUGll) to develop comments submitted on this matter. We look forward to continuing discussions with ARB Staff and other members of the JUG.

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 faithll 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.

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. (SCPPA2)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-4. Comment: *POUs Should Not be Required to Consign Their Allowance Allocations to Auction***

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."<sup>3</sup> 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."<sup>4</sup> 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")<sup>5</sup>:

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 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.<sup>6</sup>

ARB also acknowledged that some POUs would be disproportionately impacted if they were required to participate in the quarterly auction.<sup>7</sup>

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 infrastructure or financial resources to mitigate against financial exposure in the same way that IOUs can.

Because POUs 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 POUs 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 POUs more than others.

If the Cap-and-Trade auctions are undersubscribed or oversubscribed, POUs will face substantial financial risks that may impede their ability to meet compliance obligations due to the resulting financial uncertainties. Unlike the IOUs, POUs do not have shareholder funding to fall back on if there are challenges with auction participation. Any additional cost burdens incurred by POUs to manage compliance with the Cap and Trade requirements could negatively impact the ratepayers served by POUs, while achieving no measurable, incremental GHG emissions reduction benefits.

<sup>3</sup> Attachment C at 2.

<sup>4</sup> Cal. Gov. Code § 11346.8(c).

<sup>5</sup> See e.g., October 2011 Final Statement of Reasons for the Cap and Trade Regulations, 342, 564.

<sup>6</sup> Id. at 342.

<sup>7</sup> Id. at 578-579, 580-581

(CMUA2)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-5. Comment: *Section 95892 - The Regulations Should Not be Modified to Include Further Specificity on Uses of Allowance Value.***

As noted above, ARB Staff stated that they are considering “requiring that the auction proceeds be used for specific purposes.”<sup>8</sup> 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.”<sup>9</sup> 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.

<sup>8</sup> Attachment C at 2.

<sup>9</sup> October 2011 Final Statement of Reasons for the Cap-and-Trade Regulations, 65-66. (CMUA2)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-6. Comment: *Opposing Direct Allocation to Industrial Entities***

CMUA opposes ARB’s proposal to shift allocation value away from POU’s 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.<sup>10</sup>

<sup>10</sup> Attachment C at 5

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 POU’s with sizable industrial load, the severe reduction in allowance allocations will inhibit the ARB’s intended use of allowance allocations. Further, both electric rate structures and the ratemaking process for POU’s

are very complex. POU's 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. POU's 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 POU's that has not been adequately evaluated by ARB staff. (CMUA2)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

#### **G-7. Multiple Comments: § 95892 (a) EDU Allocation Proposal and Methodology**

**Comment:** 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 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

#### 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 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.

Renewable Portfolio Standard (RPS) Factor Applied 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.

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 AS 32 legislation.

CARS staffs, Attachment C of the Allowance Allocation to EDUs states that "Staff is also considering requiring POUs and co-ops to consign allocated allowances to auction and requiring that auction proceeds be used for specific purposes".

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, POUs may be unable to secure a sufficient amount of allowances to meet its obligation. It is difficult for POUs 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 AS 32 requirements are carried out. Imposing a "specific use" clause would be regulatory over-reach 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. (PWP1)

**Comment:** 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. (JU1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-8. Comment: 95852(b)(4) Wording Change**

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.

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.  
(JU1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-9. Comment: 95852(b)(3) Retain Requirement to Report and Verify REC Serial Numbers**

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. (JU1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-10. Multiple Comments: Safe Harbor Proposal**

**Comment:** 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.<sup>8</sup>

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."<sup>9</sup> 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 safe harbor from the prohibition against resource shuffling for ISO real-time market transactions.<sup>10</sup> 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.

<sup>8</sup> See proposed changes to cap-and-trade regulation at 17 CRR Section 95852(2)(a)(10).

<sup>9</sup> 17 CRR Section 95802(a)(336).

<sup>10</sup> California Government Code Section 11349 requires that proposed regulations do not conflict with or are not contradictory to existing law.

(CAISO2)

**Comment:** ARB should not exclude EIM from the resource shuffling safe harbor. 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 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. (PACCORP1)

**Comment:** ARB Should Not Exclude EIM from the Resource Shuffling Safe Harbor  
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. (EIM-ENT1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.

**G-11. 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 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. (PACCORP1)

**Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2017 Cap-and-Trade Regulation Final Statement of Reasons.



## **VI. SUMMARY OF COMMENTS MADE DURING THE SECOND 15-DAY COMMENT PERIOD AND AGENCY RESPONSE**

Chapter VI of this FSOR contains all comments submitted during the second 15-day comment period, with ARB's responses. The second 15-day comment period for additional proposed amendments commenced on April 13, 2017, and ended on April 28, 2017.

ARB received 15 letters on the proposed second 15-day amendments during the second 15-day comment period. Table VI-1 below lists commenters that submitted oral and written comments on the proposed amendments, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day and 15-day comment periods are available here: <https://www.arb.ca.gov/regact/2016/ghg2016/ghg2016.htm>

This rulemaking is for amendments to the ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. However, comments were also submitted to this rulemaking which relate to the separately noticed Cap-and-Trade program rulemaking, which is outside the scope of the proposals identified in the Staff Report, Notices of Modified Regulatory Text, and this FSOR. Statute only requires responses to comments directly submitted as part of a specific rulemaking, and this FSOR provides responsive comments only to those comments related to this specific rulemaking.

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/ghg2016/ghg2016.htm>

### **A. LIST OF COMMENTERS**

**Table VI-1**

<b>Abbreviation</b>	<b>Commenter</b>
WSPA4	Catherine Reheis-Boyd, Western States Petroleum Association, Written Testimony: 4/27/2017
SCPPA3	Sarah Taheri, Southern California Public Power Authority, Written Testimony: 4/27/2017
WC1	Melissa Poole, The Wonderful Company LLC, Written Testimony: 4/28/2017
CAISO3	Andrew Ulmer, California ISO Written Testimony: 4/28/2017

Abbreviation	Commenter
AMGAS3	Brian Pickard, Amerigas, Written Testimony: 4/28/2017
LOL1	Douglas Findley, Land O Lakes, Written Testimony: 4/28/2017
AP2	Keith Adams, Air Products, Written Testimony: 4/28/2017
CALCHAMBER3	Amy Mmagu, California Chamber of Commerce, Written Testimony: 04/28/2017
CLFP2	John Larrea, California League of Food Processors, Written Testimony: 4/28/2017
CCEEB3	Gerald Secundy, California Council for Environmental and Economic Balance, Written Testimony: 4/28/2017
LADWP4	Cindy Parson, Los Angeles Department of Water and Power, Written Testimony: 4/28/2017
PGE4	Nathan Bengtsson, Pacific Gas and Electric, Written Testimony: 4/28/2017
SMUD4	William Westerfield, SMUD, Written Testimony: 4/28/2017
TRINITY1	Charles Lee, Trinity Consultants, Inc., Written Testimony: 4/28/2017
MSR2	Martin Hopper, M-S-R Public Power Agency, Written Testimony: 4/28/2017

## B. MRR General Comments

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### B-1. Comment: *Section 95105(c)(3) Facility Block Diagrams*

WSPA appreciates the clarification of “combustion emissions” through the replacement of that term with “combustion units”. However as noted in previous comment letters, this section still requires that the location of every meter, pressure gauge, or temperature gauge that is used in emissions and CWB calculations be identified on a diagram. WSPA requests the following deletion (in bold):

~~“Identification of measurement device location, and the location of any additional devices or sampling ports. Reference to one or more diagrams (simplified block flow or piping and instrumentation diagrams) that provide a clear visual representation of the relative **the locations and** relative positions of all measurement devices and **sampling locations**, as applicable, required for calculating covered emissions and covered product data (e.g. temperature, total pressure, HHV, fuel consumption).~~

The diagram(s) must include ~~and label~~ fuel sources, combustion emissions units, and production processes, as applicable.  
(WSPA4)

**Response:** See response to Comment B-11 in Section IV of this document. The intent of the requirement is not to require identification of every meter, pressure gauge, or temperature gauge. The reporters should provide generalized schematics and it is not necessary to distinctly identify or display every device. To clarify this, the word “all” was removed during the Regulation update process, and “as applicable” was also added, to generalize the requirement. In addition, the proposed revision refers to a “simplified block diagram” as defined in MRR, which clearly indicates that detailed architectural or engineering drawings are not required. Staff intends to provide guidance on the level of detail expected in the diagrams.

## **B-2. Comment: *Facility Block Diagrams***

PG&E supports ARB’s clarification to this section which preserves the value of the diagrams while eliminating the administratively burdensome need to include an excessive level of detail. (PGE4)

**Response:** Staff appreciates the support for the Regulation update.

## **C. Fuel Supplier and Biofuel Reporting Requirements**

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### **C-1. Comment: *Revised “Importer of Fuel” Definition***

As outlined in its initial comments<sup>3</sup> and reiterated in its supplementary comments,<sup>4</sup> AmeriGas continues to strongly support the ARB in maintaining a robust and accurate greenhouse gas reporting program through the amendments to the MRR when necessary. AmeriGas’s prior comments proposed further edits to the “Importer of fuel” definition designed to address the risks of potential disaggregation of emissions positions within the industry. AmeriGas appreciates the ARB’s consideration of those comments and supports the revised definition of “Importer of fuel” as a careful and appropriate way to address these concerns.

We believe that the revised “Importer of fuel” definition is comprehensive and clear and that it will work to further reduce system leakage. We encourage the ARB to use revised supplementary guidance materials as a way to further elucidate the implications of this new definition. In particular, such guidance could make clear that entities may not use multiple contract (“daisy”) chains, collaborate with unaffiliated entities, or employ other complicated distribution schemes to avoid becoming a point of regulation under the MRR.

<sup>2</sup> 17 CCR § 95100, et seq. The MRR was developed pursuant to the Global Warming Solutions Act of 2006 (“AB 32”)

<sup>3</sup> Comments of AmeriGas Propane, L.P. to Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, September 12, 2016. (AMGAS3)

**Response:** Thank you for the support. Also, please see responses to Comment C-1 in Section IV and Comment C-2 in Section V of this document for additional information.

### **C-3 Comment: *Section 95102 Gas-to-Oil Ratio Definition***

Several key WSPA issues regarding the First 15-day MRR Regulation Amendments Modification package were not addressed in any manner in the Second 15-day package. Consequently, the following issues remain unresolved: Total GOR is proposed to include calculations for “well testing venting and flaring” and “associated gas venting and flaring”. WSPA requested that ARB provide clarity on this issue (i.e., identification of the issue that is being addressed with this change). (WSPA4)

**Response:** Staff believes the proposed language in MRR is clear, and has provided further information in the MRR 2016 Initial Statement of Reasons (pages 83 to 85) for this rulemaking. Specifically, when using the methods in these sections for quantifying emissions from well testing (venting and flaring) and associated gas venting and flaring, the “GOR” value should represent the total GOR as defined in the proposed revision to section 95102. Thus, the GOR value used for these methods should include the total associated gas separated from oil and produced water, including any gas separated prior to the collection of a flash liberation test.

## **D. Product Data Reporting**

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### **D-1. Comment: *Section 95103(k)(6) Calibration Frequency***

Air Products strongly supports the inclusion of hydrogen plants in the extension of the pressure differential flow meter inspection frequency to once every six years, to preclude the unnecessary shutdown of continuously operating facilities. ARB recognized the importance of such flexibility in the first 15-day Proposed Modifications to §95103(k)(6)(A)(1), providing the option of extending flow meter inspections to a six-year frequency when such devices are used in a refinery. Air Products recommended, and appreciates the inclusion of, this flexibility to hydrogen plants, as well. Hydrogen plants are integrally linked with refineries, operate continuously, and infrequently have maintenance outages. In fact, our hydrogen plant outages are closely coordinated with our refinery customers to coincide with their outages to minimize operating interruptions (and the negative environmental impacts of an un-needed shut-down/start-up cycle). (AP2)

**Response:** As described in Comment B-5 of Section IV of this document, staff agrees with the comment and updated the regulation accordingly.

**D-2. Comment: *Section 95114(j) Hydrogen Product Sales Reporting***

- Air Products supported the revisions to the hydrogen product sales reporting requirements included in the first Proposed 15-Day Modifications, narrowing the required sales reporting to just those end uses – petroleum refining and vehicle fueling which will inform ARB’s Low Carbon Fuel Standard. These changes will reduce the reporting burden and afford better protection to confidential business information.
- Air Products further supports the minor revision included in the Proposed Second 15-Day Modifications which allows the option of reporting products sales at the entity-level, when appropriate. This is more practical when hydrogen sales to vehicle fueling stations are made to an entity deploying that product to multiple fueling stations.
- Ideally, we believe ARB’s need for data regarding sales to vehicle fueling stations would be equally served by allowing hydrogen producers to report an aggregate value for all such sales, rather than require the greater granularity of sales data at the facility or entity level. Air Products again encourages ARB to consider the adequacy of an aggregated sales value to simplify the required reporting and provide further protection to confidential business information.  
(AP2)

**Response:** Please see the response to Comment D-7 in Section IV of this document, which responds to a similar comment.

**D-3. Comment: *Section 95114(e) Clarification of the Methods Required for Feedstock Characterization for Hydrogen***

- Air Products seeks (recommends) agency clarification of the revised language regarding feedstock characterization for hydrogen plants that was offered in the first Proposed 15-Day Modifications.
  - First, there is confusion about whether changes proposed in the first 15-Day Modification were actually intended, since the summary of proposed changes in the “First Notice of Public Availability of Modified Text and Availability of Additional Document”, issued December 23, 2016 states:

*“I. Modifications to Section 95114. Hydrogen Production. Staff is not proposing changes to this section”*

- ...while, in fact, there are changes shown in the Proposed 15- day Modifications. So, were changes proposed? Were the changes accepted?
- Second, no portion of section 95114(e) in the Second Proposed 15-Day Modification is shown to indicate subsequent changes... because the first proposed changes were accepted, no changes to the entire section (e) were intended, or the decision to make changes to section (e) was reversed?

- If ARB did intend to change the language of §95114(e), as shown in the first Proposed 15-Day Modifications, we seek the clarification regarding the intent and effect of the proposed changes. Specifically:
    - The text that was stricken [§95114(e)(1)] describing the operator's obligation to report feedstock characterization included the wording:
 

*“Carbon, atomic hydrogen, and molecular hydrogen content for each feedstock using engineering estimates based on measured data as specified below.”*

...which further proceeds to describe for gaseous feedstocks the requirement to make such a characterization based on at least monthly analyses.

[§95114(e)(1)(A)]

Air Products has historically satisfied that requirement by integrating the data from on-line mass spectrometers and/or gas chromatograph analyzers, which may perform multiple analyses per hour, more than meeting the “one or more” analyses per month requirement.
    - Despite considerable similarity, the new language in the first Proposed 15-Day Modifications does not include the words “engineering estimates” raising uncertainty to any implied requirement for some more specific analysis methods, and potentially not accepting our historical reliance on the on-line analysis methods we currently employ.
    - Further, the new language proposed under section 95114(e)(2)(B) specifies daily sampling for nonstandard (feedstock) materials, such as refinery fuel gas. Again, we seek the clarification that the on-line methods currently employed more than satisfy the “daily” sampling/analysis requirement.
- (AP2)

**Response:** The proposed revisions to Section 95114(e) were included in the Proposed Regulation Order originally posted for public comment on July 19, 2016. The summary of proposed changes posted in December, 2016 for the first 15-day comment period included (as noted in the comment above) the phrase, “Staff is not proposing changes to this section.” That means that no *additional* changes are proposed to the section for the 15-day comment period, based on the 45-day comments that were received. The revised Section 95114(e) in the MRR that was included in the first 15-day comment package matched the same section in the original Proposed Regulation Order. The revisions, as originally proposed, were intended. Section 95114(e) was modified only to clarify the monitoring requirements for fuels and feedstocks and not to change the intent or frequency of the monitoring requirements. Removing the term “engineering estimates” did not change the monitoring and reporting requirements. On-line analyzers that measure the required parameters daily, or more frequently than daily, do comply with the requirements, so long as the data are averaged and reported as described in MRR.

#### **D-4. Comment: *Section 95103(I) Reporting and Verifying Product Data***

WSPA supports the language change in this section which allows entities to have the option to exclude covered product data. (WSPA4)

**Response:** Staff appreciates support for the change.

#### **E. Verification Requirements**

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##### **E-1 Multiple Comments: *Verification Deadline Change***

**Comment:** ARB staff's proposed modification in the second 15-day package shift the verification reporting deadline from September 1 up to August 10. The first 15-day package suggested an August 1 date to better enable ARB staff to process the information received in time to inform future allowance allocations. In its last letter, SCPPA requested that ARB staff either maintain the currently in-place September 1 deadline or consider modifying to August 15 at the earliest.<sup>1</sup> We understand that ARB staff is concerned with the bottleneck that last minute submissions creates, but also note that moving the deadline up is very problematic for our Members. SCPPA appreciates staff's intent to find a middle ground with stakeholders' requests. However, despite the proposed shift to August 10, the reporting deadline is still problematic for SCPPA Members. The additional five days that SCPPA proposed (i.e. August 15) could make the difference in whether or not a reporting entity is able to comply with the regulation. We urge ARB staff to reconsider adopting a date no earlier than August 15 for this important deadline. (SCPPA3)

**Comment:** Moving the Mandatory Reporting Regulation (MRR) report deadline will significantly burden both reporting entities and verifiers. While we understand that the CARB is interested in moving the date in order to provide more time for internal quality assurance checks, calculation, analysis, and the data notifications and postings needed to complete mandated activities under the cap-and-trade program, this shift will significantly negatively impact the regulated entities which have set up practices around the September 1st deadline.

Regulated entities in the state have incorporated the September 1st into their business practices to ensure that they are complying with the regulations as set forth by the CARB. (CALCHAMBER3)

**Comment:** CCEEB appreciates the shift of the verification deadline from August 1 to August 10; however, we would like to reiterate the request from a large cross-section of stakeholders and compliance entities to accept the proposed compromise date of August 15. The thorough and time-intensive verification process makes every additional day valuable as compliance entities work to provide accurate and verified data. An August 10 deadline moves up the verification deadline by almost three weeks. We understand ARB staff needs sufficient time to perform its required tasks; however,

compliance entities also require a great deal of time due to the risks associated with submitting inaccurate or flawed data. CCEEB again urges ARB to acknowledge the above-stated arguments and accept August 15 as an equitable compromise. (CCEEB3)

**Comment:** In the second 15-day modifications to the proposed MRR amendments, ARB proposed a revised deadline of August 10 to complete verification of the annual greenhouse gas (GHG) emissions data reports. While August 10 is better than ARB's earlier proposed deadline of August 1, shortening the verification period by three weeks may create a hardship to complete verification of the more complicated reports. Not meeting the verification deadline would have significant adverse consequences.

As stated in previous comments, LADWP believes the amount of time allotted to verify an annual GHG emission report should be no less than three months. The verification period should be long enough for the verifiers to do a thorough job reviewing the reports, and for reporters to respond to questions that arise during the verification process and make corrections as needed. Verification of the reports ensures good quality data, so the verification process should not be rushed.

An August 10 verification deadline would allow five months to verify facility and supplier emissions data reports that have a reporting deadline of April 10. An August 10 verification deadline would allow less than two and a half months to verify electric power entity reports that have a later reporting deadline of June 1 (for data availability reasons). The electric power entity reports are data intensive reports complicated by additional requirements such as the "lesser of analysis" and the RPS Adjustment guidance. September 1 would be a much more appropriate verification deadline for electric power entity reports.

LADWP submits the following recommendations for ARB's consideration:

- 1) Rather than a one-size-fits-all verification deadline, there should be two different verification deadlines, one for facility and supplier reports (August 15) and a later verification deadline for electric power entity reports (September 1). This would allow a minimum of three months to verify the electric power entity reports, while providing verified facility and supplier data to ARB staff a little sooner so they can calculate allowance allocations and compliance obligations. ARB's summary of reported 2015 GHG emissions includes 686 facility and supplier reports and 118 electric power entity reports; the vast majority of those reports would be subject to the earlier verification deadline. LADWP urges ARB to strike a balance between the amount of work reporters and verifiers need to do to complete the verification process, and the amount of work ARB staff needs to do after the reports are verified, which varies depending on the type of report.
- 2) Allow reporting entities to request an extension of the verification deadline if needed, with appropriate justification, to provide flexibility in the event there are unresolved issues that will affect the verification statement. For example, more time may be needed to fix correctable errors to avoid an adverse verification opinion, or to



resolve rule interpretation questions and/or nonconformance issues. Allowing more time if needed to complete the verification process would be better than issuing an adverse verification statement to meet an earlier verification deadline. (Note: an adverse verification statement would actually create more work for ARB staff, so should be avoided if possible.)

3) Streamline the reporting and verification requirements to reduce the verification labor burden. If verification of the reports is to be completed three weeks earlier (by August 10 instead of September 1), LADWP recommends that ARB form stakeholder groups to review each sector's reporting and verification requirements and reevaluate/streamline requirements to reduce the verification burden. (LADWP4)

**Comment:** PG&E appreciates the proposed shift of the verification deadline from August 1 to August 10. As many stakeholders have commented, the rigor of the verification process makes every additional day valuable as entities seek to provide accurate, verified data. This change, while positive, still moves up the verification deadline by almost three weeks. Recognizing that ARB staff also need enough time to perform their required tasks, PG&E repeats the recommendation to split the difference and advance the verification deadline to August 15. (PGE4)

**Comment:** SMUD appreciates the movement of the proposed deadline for verification from the previously proposed August 1<sup>st</sup> date to August 10<sup>th</sup> (significantly closer to the existing September 1<sup>st</sup> deadline). SMUD is not sure that the revised date will allow verification to proceed without difficulty in meeting the August 10<sup>th</sup> date, but commits to working with our verification contractors to attempt to meet that deadline. SMUD plans to test the feasibility of meeting the August 10<sup>th</sup> deadline with our ongoing verification efforts, even prior to the effective date of the new deadline. SMUD will provide ARB with relevant information from our experience attempting to meet the August 10<sup>th</sup> deadline prior to the effective date. (SMUD4)

**Comment:** Air Products appreciates the modest extension (August 1st to August 10th) to the verification deadline. While an additional nine calendar days is moving in the right direction, Air Products still advocates for retention of the September 1st deadline for verification. We are often challenged in meeting the existing September 1st deadline, even with a verifier who has performed verification for our facility in previous years and is familiar with our operations and reporting approaches. Air Products recommends retaining the September 1st verification deadline and looking for ways to streamline the subsequent ARB review, based on some priority process (e.g. similar to criteria used for tax audits) to afford the additional time needed to align the verification process with the allowance allocation process. (AP2)

**Comment:** In recognition of WSPA and other stakeholder concerns with the moving up of the verification deadline, the revised regulatory language revision now identifies the verification deadline as August 10th. While we still believe that the moving up of the verification deadline is unnecessary and adds to the burden on both reporters and

verifiers, WSPA appreciates the compromise provided in the Second 15-day package. (WSPA4)

**Comment:** Although Land O'Lakes agrees with most of proposed modifications related to Dairy Product industry, we have a serious concern regarding the proposed changes to move the deadline to complete verification of the annual greenhouse (GHG) emission data reports earlier by approximately 22 calendar days from September 1 to August 10 each year.

Land O'Lakes is opposed to the proposed modification to the verification deadline because it will result in less amount of time available for reporting and verification entities to work together to complete the verification process. We sense that ARB is likely not taking into consideration other day-to-day compliance and other regulatory work activities that the reporting industry staff and verifiers perform while handling the verification project each year. The proposed earlier deadline will cause additional pressure and burden to both parties and may lead to a compromise in the data and verification work quality. As such, Land O'Lakes respectfully request that ARB leave the September 1 verification date, as stated in the current versions of the regulation. (LOL1)

**Comment:** Trinity generally welcomes and supports most of the proposed changes on the Proposed Second 15-day Modification document. However, we have a serious concern for ARB staff's proposed change of the deadline for completing verification from September 1 to August 10. Although an August 10 deadline may be feasible to complete verifications for reporting entities with straightforward or less complicated emission reports, we are worried that the earlier deadline will not provide enough time for verifier(s) to perform a thorough review, and thus it may lead to either a compromise in the quality of detailed verification work or premature adverse statements for those reporting entities with more complicated emission portfolios and reports.

The earlier verification deadline will adversely impact the Electric Power Entity (EPE) reports in particular as their verification period would be significantly shortened from three (3) months to two (2) months and 10 calendar days. Considering that the verification process typically includes site-visits, detailed data checks, resolving identified issues with the reporting entities, and developing verification report deliverables, the verifiers would need at least 3 months to complete all necessary verification activities without compromising work quality. Therefore, Trinity respectfully requests that ARB preserves the September 1 verification date, as stated in the current version of the regulation. If this is not feasible, we strongly recommend ARB to consider implementing a sector-specific deadline approach as opposed to one universal deadline. In other words, ARB could implement two different verification deadlines (similar to the reporting deadlines): i) August 10 for reporting entities with reporting deadline of April 10 and ii) September 1 for EPEs with reporting deadline of June 1. Trinity appreciates ARB staff for taking the comments of industry into consideration during this rule-making process. (TRINITY1)

**Comment:** M-S-R urges the Board to reject the proposed amendments to the verification timeline, and retain the current deadline of September 1. In the proposed amendments to the MRR first released in August 2016, CARB sought to move the verification deadline in Section 95103 from September 1 to August 1 of each year. Opposition to the proposal was almost universal, with stakeholder representing a broad range of compliance entities, as well as verifiers, expressing concerns with the ability to accurately complete the verification process earlier than September 1. The Second 15-Day Changes, in response to stakeholder feedback and opposition to the August 1 deadline, alters the proposal by moving the deadline to August 10. While M-S-R appreciates CARB staff's recognition of the need for more time to complete the verification, shortening this already aggressive timeline by 20 days still has the potential to compromise the accuracy of the reports and verifications submitted, ultimately resulting in greater overall inefficiencies in the process. M-S-R understands that staff seeks this change due to the need to align with timelines set forth in the cap-and-trade program regulation. However, as M-S-R noted in comments to this Board submitted on September 19, 2016, which were echoed in both oral and written comments submitted by a broad range of stakeholders, the accelerated schedule compromises the integrity of the verification process. There is nothing in the August 2, 2016 Staff Report that supports a determination that compliance entities will not be adversely impacted by the accelerated verification deadline or that is feasible to meet this new deadline, and the Board is asked to reject this proposal.

The verification process cannot begin until the emissions reports are final, and while entities can endeavor to complete their reports and submit them early, the collection and compilation of the data necessary to complete the EPE reports is a complex process. Even with diligence on the part of the reporting entity, the necessary data is not solely within the control of the reporting entity, and delays in receiving data from third parties, or the time required to review and correct such data must be part of the overall timeline. Any delays in obtaining and verifying data from third parties delays the EPE's process for reviewing the relevant data and ensuring that the final submission is accurate; M-S-R is rightfully concerned that any further constraints on this timeline would increase the risk of inadvertent errors and inaccuracies in the final submissions.

Furthermore, even with on-time or early completion of the EPE reports, the verification process itself is necessarily time consuming. Interactions with the verifier to clarify potential questions, and the iterative processes to review and assess the reports are time-consuming exercises. Staff had acknowledged the significant concerns raised by stakeholders and previously noted that further workshops or meetings would be held to address this issue. However, there were no further deliberations to address the very real concerns with the accelerated timeline, including the added burden that it would place on compliance entities and verifiers, or whether this shortened timeline is even practical or feasible.

M-S-R is very concerned that accelerating the verification timeline will lead to greater errors, or issuance of "qualified verifications" as verifiers attempt to hasten completion without sufficient time. Not only would such an eventuality result in a less efficient

verification process, but it could compromise the timely allocation of allowances to electrical distribution utilities such as M-S-R's members. While staff's acknowledgment that the August 1 deadline was too aggressive and resulting proposal to move the new deadline to August 10 is much appreciated, the result is unfortunately the same. M-S-R respectfully urges the Board to reject the proposed amendments to Section 95103(f) and (h) and retain the September 1 deadline for verification of emissions reports. (MSR2)

**Comment:** While we are generally pleased with the proposed amendments, we respectfully request that ARB consider maintaining the previously established verification and reporting deadlines under section 95103(f) (Greenhouse Gas Reporting Requirements). Changing the verification deadline from September 1 to August 10 of each year will cause unnecessary challenges for verifiers and covered entities alike. Pushing up the date will only cause there to be less time for the parties to work together to ensure data is accurate and complete, while providing no significant benefit to the Cap-and-Trade program. For this reason, we recommend that ARB leave the September 1 verification date, as proposed in previous versions of the regulation. (WC1)

**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. (CLFP2)

**Response:** See response to similar comments made on this topic under Comment E-1 in Section IV of this document.

#### **E-2. Comment: *Section 95131(b)(14)(B) - Requirements for Verification Services***

Several key WSPA issues regarding the First 15-day MRR Regulation Amendments Modification package were not addressed in any manner in the Second 15-day package. Consequently, the following issues remain unresolved: For clarification of intent of this section, WSPA requested that the first sentence in 95131(b)(14)(B) be revised to state "Verifiers must confirm via a representative sampling and review of covered product data..." (WSPA4)

**Response:** ARB staff believes the currently proposed language is appropriate for a robust review of covered product data by verifiers, while still allowing the flexibility of risk-based sampling. The intention of the proposed language is to ensure that verifiers are reviewing the covered product data reporting for conformance with MRR, such as ensuring that all reported covered product data meets the regulatory definitions and that the reporting entity is measuring and reporting those products using appropriate methodologies. ARB still expects that, in many cases, verifiers will seek to gain reasonable assurance that no material misstatement is present by reviewing a risk-based sample of reported covered product data in additional detail (for instance, by reviewing records of meter appropriateness and calibration, sampling raw data, and tracing a portion raw data back to its source).

**E-3. Comment: *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. (CLFP2)

**Response:** In the 45-day regulatory amendments in section 95133(f)(1), ARB has proposed reducing the timeline for COI review by ARB from 30 working days to 20 (calendar) days. ARB will continue to endeavor to review and process COI forms as quickly as practical and will seek to streamline this process further. However, ARB believes the proposed 20 days turnaround is necessary for complicated potential COI situations.

**E-4. Comment: *Section 95131(b)(12)(D) and (E) – CWB Material Misstatement Assessment***

Several key WSPA issues regarding the First 15-day MRR Regulation Amendments Modification package were not addressed in any manner in the Second 15-day package. Consequently, the following issues remain unresolved: The MRR Amendments introduce the term “reporting unit” which is not consistent with the terms used in the product based benchmarks. For clarity, WSPA proposed that the term “benchmark units” be used. This is consistent with Table 9-1 in the regulation. (WSPA4)

**Response:** Changes made in the First 15-day regulatory amendments eliminate the use of the term “reporting unit” in favor of the term “units of measurement.” ARB believes this term is broadly understood and will lead to standardization in how verifiers calculate material misstatement.

**E-5. Comment: *§95131(b)(12)(D) - Material Misstatement Assessment for Thermal and Non- Thermal Fields***

Several key WSPA issues regarding the First 15-day MRR Regulation Amendments Modification package were not addressed in any manner in the Second 15-day package. Consequently, the following issues remain unresolved: WSPA continues to oppose the proposed change which disadvantages some operators and our entire industry sector over other sectors. ARB should apply the same requirement to oil and gas production as all other sectors (i.e., material misstatement based on units of measure, in this case barrels). (WSPA4)

**Response:** See the response to similar comments under Comment E-5 in Section IV of this document.

## **F. Electric Power Entities**

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### **F-1. Multiple Comments: *Lesser of Analysis Exemptions in §95111(b)(2)(E)(1)***

LADWP supports ARB's proposal to re-insert the exemptions from the "lesser of analysis" for grandfathered RPS resources and dynamically tagged deliveries.

LADWP would also like to emphasize the following important points from our previous comments:

- For future reference, application of the "Sum of Lesser of MWh" equation should be limited to only fixed schedules and situations where substitute electricity may be provided. It should not be applied to zero emission generating facilities tied to a California Balancing Authority since there is no substitute electricity in that case.
- If application of the "Sum of Lesser of MWh" equation produces inaccurate results, the rule should allow the reporter to use settlement or invoice data that is more accurate. (LADWP4)

**Comment:** Support for Reinstatement of Exemptions for Grandfathered Contracts and Dynamically Tagged Power Deliveries from the Lesser-of Analysis. SCPPA strongly supports ARB's proposal that, as compared to the first 15-day amendments, would re-insert the exemptions for grandfathered contracts and dynamically tagged power deliveries from the "lesser of" analysis.<sup>2</sup> Maintaining these provisions will avoid what would have been a significant increase in the administrative burden placed on reporting entities to comply with the regulations. Reinstatement of the exemptions will allow our Members to keep their customers' costs down as a result. ARB staff had previously noted that it was seeking additional information from stakeholders to understand the implications of this policy shift. SCPPA offered input on what we foresaw to be the key issues with removing these two exemptions, and is now pleased to see that staff has made favorable changes to address our concerns. (SCPPA3)

<sup>2</sup> "Proposed Second 15-Day Modifications to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions", Appendix A, page A-10.

**Comment:** SMUD also appreciates the restoration of the exclusions in the requirement in section 95111(b)(2)(E)(1) to prepare a "lesser of" analysis for imported power. The previously proposed amendments from December 2016 had removed this exclusion for grandfathered RPS contracts and dynamically scheduled renewable imports, and SMUD and other stakeholders requested the exclusion be restored. These contracts are appropriately excluded from ARB's "lesser of" analysis because the companion "lesser of" analysis for qualifying "bucket 1" products in the State's Renewable Portfolio Standard program did not apply to these contracts. (SMUD3)

Response: ARB disagrees with the "Sum of Lesser of MWh" equation limitations requested by LADWP. The lesser of analysis should be applied to imports from applicable zero emission generating facilities tied to a California Balancing Authority, because there is the possibility of substitute power, given that the carbon intensity of the entire balancing authority is greater than zero, given the diversity of sources that contribute to the resource mix. In the event the application of the "Sum of Lesser of MWh" equation produces inaccurate results, the entity should consult with ARB and its verifier. ARB appreciates the support from stakeholders.

## **F-2. Multiple Comments: *Accounting for EIM Emissions***

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 greenhouse gas emissions associated with secondary dispatches that may occur in connection with EIM transfers.<sup>3</sup> 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.<sup>4</sup>

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.<sup>5</sup> 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.

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<sup>3</sup> 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.

<sup>4</sup> 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.

<sup>5</sup> More information on the ISO's stakeholder initiative is available at the following website: <http://www.caiso.com/informed/Pages/StakeholderProcesses/RegionalIntegrationEIMGreenhouseGasCompliance.aspx>

(CAISO3)

**Comment:** Section 95111(h) – Reporting Requirements for the California Independent System Operator (CAISO) Energy Imbalance Market (EIM). PG&E supports these changes to bring the MRR in-line with provisions of the Cap-and-

Trade Regulation which establish ARB's interim methodology for addressing the GHG obligation for secondary emissions from the EIM. We expect that the interim methodology will address ARB's concerns in the short term, and that the ARB and CAISO will achieve their objective of accurately and fairly accounting for these emissions in the near future. (PGE4)

**Response:** ARB appreciates the support of CAISO on this issue. ARB agrees that the bridge solution is intended to provide an accurate basis for emissions reporting for interim use. With regard to CAISO'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 appropriate for ARB staff and stakeholders to carefully review that optimization design before MRR is amended to include it. If CAISO finalizes the two-pass market optimization, ARB will consider appropriate regulatory changes to align its regulations with such improvements at that time. Further, it is not possible for ARB staff to build a regulatory mechanism to rely on a new method of emissions quantification before such that new method is developed. ARB staff looks forward to working with CAISO and the public as this process continues.

### **Comment F-3. *CAISO as Reporting Entity***

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.<sup>6</sup> 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. (CAISO3)

**Response:** ARB appreciates the support of CAISO on this issue.

#### **Comment F-4. *EIM Safe Harbor***

**Comment:** 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 greenhouse gas emissions associated with secondary dispatches that may occur in connection with EIM transfers.<sup>3</sup> 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.<sup>4</sup>

<sup>3</sup> 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.

<sup>4</sup> 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.

(CAISO3)

**Response:** This issue is out of scope for this MRR rulemaking as it pertains to provisions in the Cap-and-Trade Regulation. This issue will be addressed in the 2017 FSOR for the Cap-and-Trade Regulation.

#### **G. Miscellaneous Comments**

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No comments were submitted during the second fifteen-day comment period related to the Cap-and-Trade regulation.

## **VII. SUMMARY OF COMMENTS MADE DURING THE SECOND ARB BOARD HEARING AND AGENCY RESPONSE**

Chapter VII of this FSOR contains all comments submitted ARB Board meeting on June 28, 2017, with ARB's responses.

During the Board meeting, 3 people provided verbal testimony. Table VII-1 below lists the commenters, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day and 15-day comment periods are available here: <http://www.arb.ca.gov/regact/2017/ghg2017/ghg2017.htm>. Transcripts for any verbal testimony presented at the second board meeting is available here: <https://www.arb.ca.gov/board/meetings.htm>.

### **A. LIST OF COMMENTERS**

**Table VII-1**

<b>Abbreviation</b>	<b>Commenter</b>
CAISO4	Andrew Ulmer, California Independent System Operator Verbal Testimony: 6/29/2017
LADWP5	Cindy Parsons, Los Angeles Department of Water & Power Verbal Testimony: 6/29/2017
MSR3	Susie Berlin, MSR Public Power Agency Verbal Testimony: 6/29/2017

### **B. Comments Provided at June 29, 2017, Board Hearing**

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#### **B-1. Comment: *Support for ARB Interim EIM Approach***

And as you know, we operate the bulk of California's high voltage transmission system as well as a portion of Nevada's high voltage transmission system. We're also the market operator for the western Energy and Balance Market. And that market effectively allows participating balancing authorities in the western interconnection to transfer electricity among one another. And it's one of the issues in the proposed amendment with respect to how to account for electricity imports into the ISO that arise as a result of these transfers.

And then the first point is with respect to the proposed amendments related to the Energy and Balance Market. We have worked quite closely with ARB staff and stakeholders in ARB's process, and we support the interim approach for accounting for emissions associated with these electricity imports.

The second point I want to make is that we are working on operational enhancements that we believe will allow for more accurate accounting of emissions associated with these transfers. And when we receive authority from our own governing board to pursue these changes, these operational enhancements, we're going to come back and ask that ARB revise its regulation again to eliminate the bridge solution that was referred to. And we expect to have a close working relationship with ARB staff and also stakeholders in the ARB process as well as our own processes as that effort goes forward. (CAISO4)

**Response:** Staff appreciates the support for the Regulation update. Also, please see the response to comment F-10 in Section IV of this document, which addresses similar comments made during the 45-day comment period for this rulemaking.

### **B-2. Comment: *Revision to Lesser-Of Analysis***

And we do appreciate the reinstatement of the exemptions from the lessor of analysis, because that will certainly minimize the amount of extra work that we have to do. So thank you very much for reinstating those. (LADWP5)

**Response:** Staff appreciates the support for the Regulation update. For more information related to this change, please also see the response to comment F-4 in Section IV of this document, which addresses similar comments made during the 45-day comment period for this rulemaking.

### **B-3. Multiple Comments: *Verification Deadline Update***

**Comment:** One of the concerns we did have was with the verification deadline change. We had proposed a couple of suggestions, which I understand that staff is moving forward with a single verification deadline for all reports. We had proposed having two different reporting deadlines, depending on -- or two different verification deadlines, depending on the reporting deadline. So the reports that were due April 10th would have the August 10th verification deadline, and the ones that are due on June 1st would have a September 1st deadline. So we understand that this is an experiment as far as seeing if everyone can get it done early. So -- but we'd like you to remain open to the idea of the possibility of having two different verification deadlines based on the reporting deadline. And the reports that would be subject to that June 1st reporting deadline are only 15 percent of the overall reports. So just want keep the door open to that.

And then, in addition, we were thinking that there should be some sort of mechanism for reporters to request an extension if necessary, just in case they run into trouble and have unresolved problems that could result in an adverse verification statement; where if they had a little extra time, they might be able to resolve that. And we haven't heard any discussion about having such a possibility of an extension. I know it hasn't been in practice up until now. But just again a suggestion. (LADWP5)

**Comment:** MSR is comprised of three municipal and publicly owned utilities that are subject to the reporting requirements that are due on June 21st. And we just wanted to make a few points on that. We really appreciate staff's proposed change from their original proposal to move that deadline up 30 days. And I appreciate that there -- that the changes need to be made to support the Cap-and-Trade Program. We think the Cap-and-Trade Program is an essential tool and hope to be speaking in favor of that very soon.

But as it stands right now, the members of MSR are very concerned with the accelerated deadline. We have then been working this past year with the assumption that there would be an earlier deadline, and the soonest that we are able to confirm that -- or the soonest that a verification is projected to take place is August 14th and that's with the members seeking diligently to try to meet the earlier deadline. That's what they're verified -- the earliest they can get it done. And that's assuming that there are no glitches or additional data needs.

And the reason for this is not because of a delay in the reporting entities getting their information together. We appreciate staff believes that we'd pursue this sooner, turn your papers in sooner, start the process sooner, that you can get done sooner. But that's not always the case. For example, for reporting for the MSR members, they have to report all the REC serial numbers for generation during the calendar year. Generation of RECs that occur in December of 2016, they're not assigned direct serial numbers until March. So those numbers are assigned in March. And then the RECs, if they weren't owned by the generator -- or by the reporting entity need to be transferred to the reporting entity. Then they have those numbers, then they can finish their reports. But we're already talking about into April, potentially May, depending on the time frame when the RECs are transferred to the reporting entity and so on down the line.

So it's an iterative process. It is not something that's in the sole control of the reporting entity. And we're very concerned that there's just not going to be sufficient time to ensure accurate reporting and accurate and sufficient verification of those reports; and we think that the integrity of the numbers is very important. And we don't want to have to come back seeking corrections because the process was accelerated or rushed along the way.

So we strongly encourage retention of the original verification deadline of August. Thank you. Excuse me. Of September 1st, not August. (MSR3)

**Response:** Please see the response to comment E-1 in Section IV of this document, which addresses similar comments made during the 45-day comment period for this rulemaking. In addition, MRR recognizes the issues with timely collection of REC information for EPEs by including a later reporting deadline of June 1<sup>st</sup>, as compared to the facility reporting deadline of April 10<sup>th</sup>, and allowing

entities to fully reconcile the retirement of RECs associated with RPS adjustments within 45 days of the reporting deadline.

#### **B-4. Comment: *Clean Power Plan Requirements Dates***

And with regards to the new reporting requirements for electricity generating units, it wasn't clear to us in the rule when those requirements would take effect. I understand from the staff presentation that they would take effect in 2022 for the 2021 data, but we didn't see that in the rule. So we would appreciate it if that could be clarified.  
(LADWP5)

**Response:** As specified in proposed section 95160(b) of MRR, the Clean Power Plan provisions would become effective starting with 2021 data submitted in 2022, if U.S. EPA has approved, as memorialized by publication in the Federal Register and Code of Federal Regulations, that provision as part of California's plan for compliance with the Clean Power Plan.

### **VIII. 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, a portion of the rule, the "Test Procedure for Determining Annual Flash Emission Rate of Gaseous Compounds from Crude Oil, Condensate, and Produced Water" was recently peer reviewed as a component of a separate rulemaking, concerning "Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities" and approved by the Board in Resolution 17-10 (Mar. 23, 2017). The Test Procedure has not been further modified, and so there is no need for a second and duplicative review of the identical text. Staff has therefore included this proposed procedure for adoption here as part of MRR as well.

With regard to the remainder of the rulemaking, 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 for in section 57004 was or needed to be performed.