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

November 2014

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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 Date: September 18, 2014
Agenda Item No.: 14-7-6

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), to integrate the AB 32 Cost of Implementation Fee Regulation (title 17, California Code of Regulations, section 95201 et seq.) (COI Fee Regulation) data reporting requirements into MRR to streamline reporting, and to collect information needed for the ARB's statewide greenhouse gas emission inventory and other ARB climate change programs. 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, 95100, 95101, 95102, 95103, 95104, 95105, 95106, 95107, 95108, 95109, 95110, 95111, 95112, 95113, 95114, 95115, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95124, 95129, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, 95158, and Appendix A and B, 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 29, 2014 and notice of public hearing scheduled for September 18, 2014.[1] 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, and other supporting documentation were made available for public review and

[1] California Air Resources Board. Notice of Public Hearing to Consider Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. Posted July 29, 2014. Available online at: http://www.arb.ca.gov/regact/2014/ghg2014/ghg14notice.pdf

comment starting on July 29, 2014, running for 45 days through to September 15, 2014. The regulatory amendments as proposed would:

- Support California's Cap-and-Trade Regulation by requiring further information in order to ensure consistency with allocation and the calculation of compliance obligations;
- Integrate the COI Fee Regulation data reporting requirements into MRR to provide for streamlined and more consistent data reporting; and
- 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.

At its September 18, 2014 public hearing, the Board approved Resolution 14-32[2] directing the Executive Officer to consider the topics in Attachment B and make additional 15-day changes as appropriate to MRR as part of a subsequent 15-day notice to the rulemaking package.

During the 45-day and the subsequent 15-day public comment period, the public submitted comments on the proposed amendments.[3] The 45-day comment period commenced on July 29, 2014, and ended on September 15, 2014, with additional oral and written comments submitted at the September 18, 2014 Board hearing. The 15-day comment period occurred from October 2, 2014 to October 17, 2014.

At a public hearing held on September 18, 2014, the Board approved Resolution 14-32, 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 18, 2014.

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, and Title 2 of the Government Code.

[2] California Air Resources Board. Board Resolution 14-32. Posted October 2, 2014. Available online at: http://www.arb.ca.gov/regact/2014/ghg2014/ghg2014.htm

[3] All public comments received on the proposed amendments can be found online at: http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=ghg2014

Some public local government agencies are subject to the current reporting regulation, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers, affecting 31 local government entities. Some entities will have minor cost increases, and some will have modest cost savings. Overall, the net fiscal effect on all of the local government agencies combined is a cost savings of $900 per year.

Staff evaluated small businesses based on reporting requirements from 2012 and 2013. 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. 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 IV 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 Period

Pursuant to the Board direction provided in Resolution 14-32, ARB released a Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (15-Day Notice) on October 2, 2014, which placed documents into the regulatory record and presented the additional modifications to the regulatory text after extensive consultation with stakeholders.[4]

B. Non-Substantive Corrections to the Regulation

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

[4] California Air Resources Board. Notice of Public Availability of Modified Text and Availability of Additional Documents. Posted October 2, 2014. Available online at: http://www.arb.ca.gov/regact/2014/ghg2014/ghg1415daynotice.pdf

1. Change term "operator" to "reporting entity": In section 95111(g), the term "operator" was changed to "reporting entity." The existing text of section 95111(g) makes clear that the registration requirement applies to "reporting entities," not solely to "operators," and this has also been ARB's long-standing regulatory practice. In context, the amendments can thus only be understood to apply to "reporting entities," like all other relevant requirements in the section, meaning that the term "operator" in the amendments is clearly a non-substantial error in a passage which on its face applies only to "reporting entities." Staff has therefore corrected this non-substantial error.

The above described modification constitutes 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:

1. California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff, May 1, 2014 (CAISO) http://www.caiso.com/Documents/ConformedTariff_May1_2014.pdf

This document was incorporated by reference because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in the California Code of Regulations. The document is 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 document was made available by ARB upon request during the rulemaking action and will continue to be available in the future. The document is also available for free on the website specified above.

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 18, 2014 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 29, 2014, and ended on September 15, 2014, with additional comments submitted at the September 18, 2014 Board hearing on the proposed amendments.

ARB received 16 letters on the proposed amendments during the 45-day comment period, including the October 2013 Board hearing. In addition, 9 commenters gave oral testimony at the September 2014 Board hearing. Commenters included representatives from the electricity and natural gas sectors, oil and natural gas extraction and refining sectors, and other reporters. To facilitate use of this document, comments are categorized into sections, and are grouped for 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 18, 2014 Board Hearing, identifies the date and form of their comments, and shows the abbreviation assigned to each.

A. LIST OF COMMENTERS

Table IV-1

Abbreviation	Commenter
BERLIN1	Susie Berlin, Northern California Power Agency & M-S-R Public Power Board Testimony: 9/18/2014
CALPINE1	Barbara McBride, Calpine Corporation Written Testimony: 9/15/2014
CCEEB1	Bob Lucas, California Council for Environmental and Economic Balance Board Testimony: 9/18/2014
CFRNG1	David Cox, Coalition for Renewable Natural Gas Written Testimony: 9/15/2014
CFRNG2	David Cox, Coalition for Renewable Natural Gas Board Testimony: 9/18/2014
IEPA1	Amber Blixt, Independent Energy Producers Association Written Testimony: 8/8/2014
KC1	Nicolas Van Aelstyn, Kimberly-Clark Corp Board Testimony: 9/18/2014
KERN1	Melinda Hicks, Kern Oil & Refining Co. Written Testimony: 9/15/2014
LADWP1	Cindy Parsons, Los Angeles Department of Water and Power Written Testimony: 9/15/2014
LADWP2	Cindy Parsons, Los Angeles Department of Water and Power Board Testimony: 9/18/2014
MSR1	Martin Hopper, M-S-R Public Power Written Testimony: 9/15/2014
MWATER1	Jeffrey Knightlinger, The Metropolitan Water District of Southern California Written Testimony: 9/15/2014 (Submitted to C&T)
NCPA1	Susie Berlin, Northern California Power Agency Written Testimony: 9/15/2014
PCORP1	Mary Wiencke, Pacificorp Written Testimony: 9/15/2014
PGE1	Matthew Plummer, Pacific Gas and Electric Company Written Testimony: 9/12/2014
RASBERRY1	Tamara Rasberry, San Diego Gas & Electric Board Testimony: 9/18/2014

Abbreviation	Commenter
SCE1	Frank Harris, Southern California Edison Board Testimony: 9/18/2014
SCPPA1	Tanya DeRivi, Southern CA Public Power Authority Written Testimony: 9/8/2014
SEMPRA1	Tamara Rasberry, Sempra Energy Utilities Written Testimony: 9/15/2014
SMUD1	William Westerfield, Sacramento Municipal Utility District Written Testimony: 9/15/2014
SMUD2	Tim Tutt, Sacramento Municipal Utility District Board Testimony: 9/18/2014
WM1	Charles White, Waste Management Written Testimony: 9/15/2014
WNEC1	Kelle Vigeland, Wheelabrator Norwalk Energy Co, Inc. Written Testimony: 9/11/2014
WPTF1	Clare Breidenich, Western Power Trading Forum Written Testimony: 9/3/2014
WSPA1	Catherine Reheis Boyd, Western States Petroleum Association Written Testimony: 9/15/2014
WSPA2	Michael Wang, Western States Petroleum Association Board Testimony: 9/18/2014

B. Electric Power Entity Requirements

Transmission Loss Factor

B-1. Multiple Comments: ***Application of the transmission loss factor to imports that are directly connected to a California Balancing Authority***

In the 45 day amendments, staff has proposed a revision to section 95111(b)(2) that would require a transmission loss factor of 2 percent to be applied to all electricity imports, including specified imports measured at the busbar.

WPTF supports this proposed amendment with one exception. Certain out-of-state resources, although considered imports under the cap and trade regulation, are in fact connected directly to the California Independent System Operator or other California balancing authority area. These resources effectively operate as in-state resources and should be treated as such. Therefore, WPTF requests that CARB further modify the regulation to explicitly exempt resources that are physically connected to a California balancing authority area from use of the 1.02 transmission loss factor:

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

Where:

CO2e = Annual CO2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EFsp = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EFsp = 0 MT of CO2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses between the busbar and measurement at first point of receipt in California.

TL = 1.0 for deliveries from resources with a first point of interconnection with a California balancing authority. (WPTF1)

Comment: Transmission Line Loss Factors §95111(b)(2)

ARB's 45-Day Proposed Language

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

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EF_{sp} = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EF_{sp} = 0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

TL = Transmission loss correction factor.

TL = 1.02 ~~when deliveries are not reported as measured at the busbar,~~ to account for transmission losses between the busbar and measurement at first point of receipt in California.

~~TL = 1.0 when deliveries are reported as measured at the busbar.~~

SCPPA Proposed Revision:

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

CO2e = MWh x TL x EFsp

Where:

CO2e = Annual CO2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EFsp = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EFsp = 0 MT of CO2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

TL = Transmission loss correction factor.
TL = 1.02 ~~when deliveries are not reported as measured at the busbar,~~ to account for transmission losses **supported by generation outside of** between the busbar and measurement at first point of receipt in **a** California **balancing authority**.

TL = 1.0 when transmission losses are supported by a California balancing authority or paid back using electricity sourced from within California. ~~deliveries are reported as measured at the busbar.~~

1. A one-size-fits-all default transmission loss factor would result in double counting of GHG emissions for transmission losses and unnecessary Cap-and-Trade program compliance costs. SCPPA's recommended revisions would provide for accurate reporting of transmission losses associated with imported electricity from specified facilities or units.

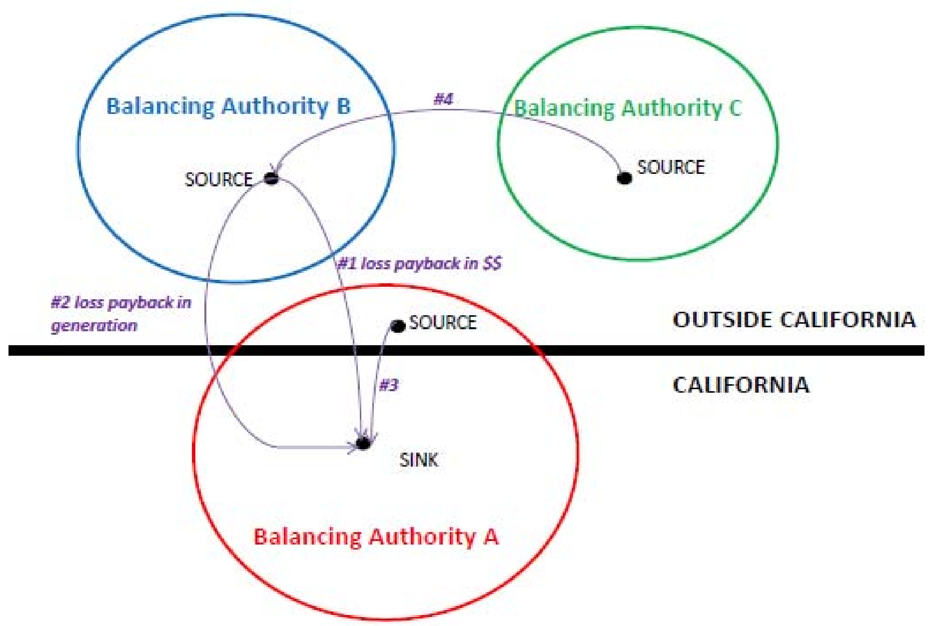
2. Compensating for transmission losses occurs naturally as part of the California balancing authority energy management system action and no transmission loss number has to be calculated. The balancing action

automatically uses the balancing authority’s internal generation to compensate for the transmission losses. Therefore, CO2e emissions associated with a balancing authority’s function to support transmission losses are embedded in its internal generation data and is already accounted for.

3. For transmission losses incurred by other entities, the entity that supported the losses needs to be compensated for the generation used to support its transmission usage. Return of transmission losses is also known as loss payback. When the loss payback is in the form of generation sourced from within California, the emissions for the energy used to pay back the transmission losses are already accounted for under the reporting requirements. Thus, in this situation, the transmission loss factor should be 1.0.

4. Applying a transmission loss factor of 1.02 in cases where transmission losses are compensated for with California generation would overstate emissions for transmission losses, and inaccurate reporting of emissions that do not exist. Therefore, the transmission loss factor of 1.0 should be retained and applied in cases where transmission losses are supported by a California balancing authority, or where transmission losses are paid back using electricity sourced from within California.

Please refer to the attached diagram illustrating different scenarios where it would be appropriate to apply either a 1.02 or a 1.0 transmission loss factor.



Situation #1
Source is in Balancing Authority (BA) "B" and sink is in BA "A". Transmission losses (TL) are paid monetarily. TL = 1.02

Situation #2
Source is in BA "B" and sink is in BA "A". TL paid back in generation.
TL = 1.0

Situation #3
Source is in BA "A" and sink is in BA "A". The balancing action automatically uses the BA's internal generation to compensate for TLs. TL = 1.0

Situation #4
Source is in BA "B" and sink is in BA "A". TLs paid from BA "C" to BA "B". TL = 1.02 (SCPPA1)

Comment: §95111(b)(2) -The 1.0 transmission loss factor for imported electricity from specified sources should be retained, to avoid over-stating GHG emissions for transmission losses that are supported by a California balancing authority or paid back with electricity sourced from California .

2. The 1.0 Transmission Loss Factor should be Retained to Avoid Over-Estimating GHG Emissions for Transmission Losses [§95111(b)(2)]

ARB Proposed Amendment

ARB is proposing to delete the 1.0 transmission loss factor for electricity imported from specified sources, and apply the 1.02 transmission loss factor to all imported electricity.

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

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

Where:

CO_2e	=	Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).
MWh	=	Megawatt-hours of specified electricity deliveries from each facility or unit claimed.
EF_{sp}	=	Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.
EF_{sp}	=	0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.
TL	=	Transmission loss correction factor.

TL = 1.02 ~~when deliveries are not reported as measured at the busbar,~~ to account for transmission losses between the busbar and measurement at first point of receipt in California.

~~TL = 1.0 when deliveries are reported as measured at the busbar.~~

As a result, all electricity imports would be inflated by two percent, regardless of whether the transmission losses are supported using electricity from within or outside of California.

Analysis and Concerns

Transmission losses are typically supported by the balancing authority through which the energy is flowing, and are compensated for using electricity produced by other generating resources. When a California Balancing Authority supports transmission losses for imported electricity, the balancing authority's internal generation is used to compensate for the transmission losses, and the GHG emissions associated with supporting the transmission losses are embedded in the balancing authority's internal generation data and accounted for as part of the in-state generating facility emissions reports. Therefore, it is appropriate to apply a transmission loss factor of 1.0 to imported electricity where transmission losses are supported by a California balancing authority.

If transmission losses are supported by a balancing authority outside of California, the owner of the electricity has to pay back the transmission losses, either financially or with electricity, to the transmission service provider. If the transmission losses are paid back with electricity sourced from within California, GHG emissions for that energy have already been accounted for under the California reporting requirements. Therefore, it is appropriate to apply a transmission loss factor of 1.0 to imported electricity when transmission losses are paid back using electricity sourced from within California.

The proposed amendment would over-estimate (double count) GHG emissions for transmission losses, and result in inaccurate reporting of GHG emissions and unnecessary Cap & Trade compliance costs for emissions that do not exist. For example, electricity imported from Intermountain Generating Station in Utah is supported by LADWP's balancing authority area and generating resources. Therefore, a transmission loss factor of 1.0 is appropriate for electricity imported: from Intermountain, because the downstream line losses are compensated for using electricity produced by California generating resources or other imported electricity, both, of which are subject to reporting under the Mandatory Reporting Regulation. Applying a transmission loss factor of 1.02 rather than 1.0 would increase reported emissions by approximately 200,000 metric tons per year.

LADWP recommends retaining the 1.0 transmission loss factor and applying it to imported electricity where transmission losses are supported by a California Balancing Authority or paid back with electricity sourced from within California. This is necessary to avoid over- stating GHG emissions for the support of transmission losses. Applying a 1.02 transmission loss factor across the board would artificially inflate California's GHG emissions and unfairly penalize California entities when a California balancing authority is supporting the transmission all the way from the generating facility into California.

Recommended Revisions to the Rule Language

> 95111(b)(2) Calculating GHG Emissions from Specified Facilities or Units. For electricity from specified facilities or units, the electric power entity must calculate emissions using the following equation:
>
> $CO2e = MWh \times TL \times EFsp$
>
> Where:
> CO2e = Annual CO2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO2e).
> MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.
> EFsp = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.
> EFsp = 0 MT of CO2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.
> TL = Transmission loss correction factor.
> TL = 1.02 ~~when deliveries are not reported as measured at the busbar,~~ to account for transmission losses **supported by generation outside of** between the busbar and measurement at first point of receipt in **a** California **balancing authority**.
> **TL = 1.0 when transmission losses are supported by a California balancing authority or paid back using electricity sourced from within California.** ~~deliveries are reported as measured at the busbar.~~ (LADWP1)

Comment: We filed written comments on the electric power entity reporting requirements. And I'd like to draw your attention to two items, in particular. The first is the proposal to eliminate the 1.0 transmission loss factor for specified imports. This amendment would overestimate GHG emissions for transmission losses when those losses are supported by a California balancing authority or paid back using electricity sourced from within California. As a balancing authority, LADWP uses our internal generating resources to make up for transmission losses within our control area and to pay back losses that we owe outside of our control area.

The GHG emissions for this makeup energy are already accounted for under the existing reporting requirements. We estimate this proposed amendment would inflate our reported GHG emissions for imported electricity by approximately 200,000 metric tons per year. That's a big number. We ask that ARB retain the 1.0 transmission loss factor to avoid inaccurate reporting of GHG emissions that don't exist and the associated increase in cap and trade compliance costs. (LADWP2)

Comment: *SMUD believes that there are nuances to the addition of transmission loss factor adjustments to imported power emissions that are not yet reflected in the proposed language.* For example, there is no need to include a transmission loss factor that would increase the imported emissions in circumstances where the contractual transaction accounts for the losses locally or via return generation. Doing so in these circumstances in effect “double counts” the emissions associated with losses on the transaction, and inaccurately increases the obligation and cost of the reporting entity.

I. SMUD Recommends Alternative Language for Inclusion Of Transmission Loss Factors When Reporting on Imported Resources

SMUD believes that the proposed revision to transmission loss factors to be used for scheduled imports from specified facilities or units requires further thought. The proposed change will result in an unfortunate overstatement of GHG emissions from electricity imports. A transmission loss factor of 1.02 is reasonable for those imports where losses from the source to a California balancing authority are “covered” by the source or by a non-California balancing authority. However, a transmission loss factor of 1.0 is appropriate for transactions where the source to California balancing authority losses are covered locally (by or within a California balancing authority), or contractually by the return scheduling of local generation (also known as “loss payback”). The emissions for the energy used to pay back the transmission losses are already accounted for under the reporting requirements, and should not be added again. Using a transmission loss factor of 1.02 in these latter circumstances in effect “double counts” the emissions associated with losses on the transaction, inappropriately increasing the GHG obligation and associated costs to the reporting entity

SMUD suggests the following edit:

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

CO2e = MWh x TL x EFsp

Where:

CO2e = Annual CO2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EFsp = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EFsp = 0 MT of CO2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

TL = Transmission loss correction factor.

TL = 1.02 ~~when deliveries are not reported as measured at the busbar,~~ to account for transmission losses **supported by generation outside of** between the busbar and measurement at first point of receipt in **a** California **balancing authority.**

TL = 1.0 when transmission losses are supported by a California balancing authority or paid back using electricity sourced from within California.

~~**TL = 1.0 when** deliveries are reported as measured at the busbar.~~
(SMUD1)

Response: Staff generally agrees with the comments that the 1.0 factor should be retained, and available for use if appropriate, and made corresponding changes in 15-day amendments to the regulation to specify that the reporting entity will provide documentation that demonstrates to the satisfaction of a verifier and ARB that transmission losses: (1) have been accounted for; (2) are supported by a California balancing authority; or (3) are compensated by using electricity sourced from within California.

B-2. Comment: Proposed Change to the Transmission Loss Factor

Section 95111(b)(2) of the MRR is being proposed to require electricity importers to use a transmission loss factor of 1.02 for all specified source imports, regardless of where emissions and generation are measured. The ARB Staff's Initial Statement of Reasons (ISOR) states,

> "The change related to the transmission loss factor is necessary to ensure the accurate reporting of transmission losses associated with imported electricity from specified facilities or units. Section 95111(a)(4) currently requires the reporting of specified source MWh to be measured at either (1) the generation source busbar, or (2) at the First Point of Delivery (POD) inside California. When measuring at the generation busbar, the transmission loss factor of 1.0 is used. When measuring at the First Point of Delivery inside California, the transmission loss

factor of 1.02 is used. The common industry practice is to electronically tag power for transmission using the NERC etagging system, but e-tags do not account for transmission loss. Using a consistent transmission loss factor will ensure that transmission losses associated with imported electricity from specified facilities or units will be accurately reported. The change related to emission factors is required to ensure the use of unified and consistent data to determine emission factors across the sector."

Contrary to the stated intent to ensure accurate reporting, the change in the MRR would promote inaccurate reporting of emissions. If generation is measured at the busbar, it is before transmission losses. For MWh reported at the busbar, the proposed change would increase the MWh by 2 percent beyond that actually produced at the facility and create phantom emissions for which the facility would have to buy allowances. This change in reporting would violate the Interstate Commerce Clause (ICC) by making the measurement of emissions 2 percent higher for generation outside California even though the point of measurement would be the same as the measurement for generation in California.

This MRR change would be significant for SDG&E's Desert Star Combined Cycle facility, which is located in Nevada, but dynamically connected to the CAISO grid. This facility does not even have e-tags since it is connected to the CAISO grid, so the ISOR argument about e-tag reporting is not applicable to Desert Star.

In order to avoid violations of the ICC, the ARB should reject the proposed changes to the MRR and instead provide clear guidance on what is required to show the MWh are calculated at the busbar. Alternatively, the MRR could be changed to indicate all MWhs reported based on e-tags will be considered as measured at the California border and so the 2 percent transmission adder would be applied.

To ensure accurate emissions reporting, SDG&E proposes the following change to the MRR:

> (2) *Calculating GHG Emissions from Specified Facilities or Units.* For electricity from specified facilities or units, the electric power entity must calculate emissions using the following equation:
>
> Where:
>
> CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).
> MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.
> EF_{sp} = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EF_{sp} = 0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.
TL = Transmission loss correction factor.
TL = 1.02 when deliveries are not reported as measured at the busbar, to account for transmission losses between the busbar and measurement at first point of receipt in California. **<u>All MWhs reported on e-tags will be considered measured at the first point of receipt in California.</u>**
TL = 1.0 when deliveries are reported as measured at the busbar.
(SEMPRA1)

Response: Staff declines to make the proposed text edit in the comment as it supports using the 1.0 transmission loss factor without adding any requirements to verify the use of the 1.0 as an appropriate factor that accounts for transmission loss. Instead, staff retained and clarified the use of the 1.0 loss factor in the proposed amendments, subject to verification, which addresses stakeholder concerns.

B-3. Multiple Comments: Transmission Loss Factors
The proposed amendments would change section 95111(b)(2) to require electric power entities (EPEs) to use a transmission loss factor of 1.02 for all specified imports. This would require the same transmission loss factor regardless of whether the specified source is measured at the busbar or at the first point of delivery. The ISOR states that because the e-tags do not account for transmission losses, a consistent transmission loss factor is necessary to ensure that transmission losses associated with imported electricity from specified facilities or units will be accurately reported. (ISOR, p. 19) NCPA understands that staff is concerned that the 1.00 factor is being applied to all transactions with no way to verify or otherwise ensure that the appropriate line losses have been accounted for. While NCPA understands CARB's concerns regarding the need to ensure that the line losses are accounted for, arbitrary application of a 2% factor to all transactions will result in the same inaccuracies the proposed amendment attempts to address, and will also cause increased costs for compliance entities and inaccurate accounting of actual GHG in the state's inventory. Accordingly, NCPA urges CARB to address the manner in which utilization of the 1.00 factor can be confirmed and verified, rather than arbitrarily imposing the higher loss factor to all transactions.

Staff's concerns regarding confirmation of the line losses applied can be addressed by reviewing the agreements that underlie transactions associated with the imports. In some instances, it will be appropriate to use 1.02. In other instances, the line loss should be calculated at 1.00. NCPA notes that there will also be instance where line losses are settled financially, and where the transactions will require use of the 1.02 loss factor, but applied to the generation resources coming from the transmission providers system and not the Specified Source Generator on the NERC e-tag.

NCPA offers the following three examples of the manner in which losses associated with specified transactions are conducted, and the manner in which the line losses can be accurately accounted-for- each of which can be confirmed by a third party verifier in viewing the transaction agreements:

> In-Kind Returns: In these transactions, the return of losses is based on a calculated amount usually defined by a loss factor in the Transmission Providers' OATT multiplied by the MWh quantity on a NERC e-tag during a particular time period, and the calculated amount of energy associated with the Real Power Losses is returned to the transmission providers system by either a generation resource within that system or a scheduled import to that system. The reporting entity should be able to show to the Third Party Verifier the transmission contract reflecting this option to validate the In Kind Return schedules of energy if they wish to claim a source lower than the emission factor of the Specified Source.
>
> Simultaneous Loss Paybacks: In these transactions, where Real Power Losses are calculated either by the Transmission Providers' OATT or a specific contract related to the specified resource and its delivery point, and the generation scheduled at the point of delivery (on the NERC e-tag) is less than the amount generated by the resource with the excess allowed to flow into the Transmission Providers system to compensate for the Real Power Losses, the reporting entity should be able to show the Third Party Verifier a busbar amount that is greater than the NERC e-tagged amount, or a contractual arrangement where the accounting for losses is tracked. In this case, the Real Power Losses associated with imports to California should be calculated by multiplying the import quantity by 1.02.
>
> Financial Settlement: In a financial settlement transaction, a calculated amount for Real Power Losses is determined in accordance with the Transmission Provider's OATT and the applicable loss factor, and the MWh quantity is then typically settled against a published price of energy at a major trading hub (such as Palo Verde or Mid-C), and a dollar amount is determined and paid to the Transmission Provider, the reporting entity will need to determine whether the Transmission Provider is an ACS or not; in these transactions, in the event that the Transmission Supplier is an ACS, the ACS's EF should be used to account for the additional 2% of Real Power Losses, and if the Transmission Provider is not an ACS, then the default EF should be used to account for the additional 2% of Real Power Losses. (NCPA1)

Comment: M-S-R urges the Board to direct that the proposed amendments be revised to: (1) allow the continued use of the transmission loss factor of 1.0 subject to confirmation of the treatment of losses;

Section 95111(b)(2) – Calculating GHG Emissions – Transmission Losses

Staff has proposed utilizing a single transmission loss factor of 1.02, rather than the current definition that allows for the use of either 1.0 or 1.02, depending upon the point at which the transaction is measured. M-S-R opposes elimination of the 1.0 factor, and notes that requiring all transactions to report 1.02 would inflate not only compliance costs, but the overall GHG inventory. M-S-R understands that CARB wants to be assured that transmission losses are accurately accounted for, but object to the arbitrary imposition of a 2% adder as the way in which to do so.

The line losses, typically referred to as Real Power Losses in the transmission providers Open Access Transmission Tariffs (OATTs), are not always treated the same way. Indeed, losses from a specified resource located outside of California and imported to California are handled in a number of ways or methods. Many of these losses are financially settled, with the underlying contracts specifying the source of the electricity that was used to account for the losses. As such, the application of a 2% adder would overstate the emissions associated with the transaction. For example, the quantity of electricity imports from the San Juan Generating Station (with an emissions factor of 1.08 MTCO2e/MWh) to the CAISO grid is the same MWh amount as what is measured at the busbar. Therefore, applying a 1.02 multiplier overstates not only the total emissions, but where those emissions come from, as applying a 1.02 multiplier to the EF of San Juan assumes the transmission losses are made up with San Juan generation, when they actually come from the transmission provider's system. This information can be verified by looking at the underlying agreements, and as such should assuage staff's concerns regarding a means by which to confirm that the losses have been accounted for.

To ensure the accuracy of the reported data, and neither over nor understate the emissions at issue, specified resources should be able to select how losses associated with their imports are settled, and provide contracts or other settlement documents to the Third Party Verifier to confirm the manner in which the losses were addressed. These losses are generally addressed in one of the following manners:

> For "in kind returns," where the return of losses based on a calculated amount usually defined by a loss factor in the Transmission Providers OATT multiplied by the MWh quantity on a NERC e-tag during a particular time period, and the calculated amount of energy associated with the Real Power Losses is returned to the transmission providers system by either a generation resource within that system or a scheduled import to that system, the reporting entity should be able to provide the Third Party Verifier the transmission contract demonstrating the election of this option and validate the In Kind Return schedules of energy if the claim is for a source lower than the EF of the Specified Source.
>
> For "Simultaneous Loss Paybacks" transactions, where Real Power Losses are calculated either by the Transmission Providers OATT or a specific contract related to the specified resource, and its delivery point and the generation scheduled at the point of delivery (on the NERC e-tag) is less than the amount

generated by the resource with the excess allowed to flow into the Transmission Providers system to compensate for the Real Power Losses, the reporting entity should be able to show the Third Party Verifier a busbar amount that is greater than the NERC e-tagged amount, or a contractual arrangement where the accounting for losses is tracked. In this case the Real Power Losses associated with imports to California should be calculated by multiplying the Import quantity by the 1.02.

> Finally, in instances where the losses are addressed by “Financial Settlement,” where a calculated amount for Real Power Losses is determined in accordance with the Transmission Provider’s OATT, and the applicable loss factor and MWh quantity is then typically settled against a published price of energy at a major trading hub such as Palo Verde or Mid-C, and a dollar amount is determined and paid to the Transmission Provider, and the reporting entity would determine whether the Transmission Provider is an ACS or not, and in the event that the Transmission Supplier is an ACS the ACS’s EF should be used to account for the additional 2% of Real Power Losses, and if the Transmission Provider is not an ACS then the default EF should be used to account for the additional 2% of Real Power Losses.

As can be seen by these examples, there is ample evidence to substantiate and confirm the loss election applied to the transaction, which is preferable to imposition of a single 2% adder to all transactions based on a single metric. Accordingly, M-S-R urges revisions to the proposed amendment to ensure that the regulation does not overstate these losses, and thereby place a greater burden on compliance entities and distort the total GHG inventory numbers. The MRR should not apply a 1.02 emissions factor for out of state specified sources with emissions factors greater than the default emissions factors when losses for transmission usage outside of the

CAISO grid are settled financially. The Board should direct staff to work with stakeholders to develop appropriate language that addresses these concerns for approval in 15-day changes. (MSR1)

Comment: The other issue -- and I won't talk about it in detail because Cindy Parsons did a very good job of addressing this is the treatment of the line loss factors. We believe that application of a 1.02 factor to all transactions provides no more accuracy than using the overuse of the 1.0 factor that staff is attempting to eliminate. We appreciate the recognition that this will also be subject to some 15-day changes based on further discussions with stakeholders on the best way to address this. (BERLIN1)

Comment: Thank you, Chairman Nichols. Tamara Rasberry representing the SEMPRA Energies, SoCal Gas and San Diego Gas and Electric. I want to thank the Board and the staff for their work on the MRR for the last -- I think going on year three or four now. But SDG&E, we still have concerns on the MRR. And they are detailed in our filed and written comments. I just want to summarize what our concern was for the Board. Section 95111(b)(2), which has been commented on earlier by LADWP. This change to the MRR requires electricity importers to use a transmission loss factor of

1.02 for all specified source imports, regardless of where the emissions are measured. But it does make a difference if the generation is measured at or near the plant or if the generation is measured at the border. The proposed change ignores this difference and will put generators -- his measurements are close to the plant at a disadvantage. While the argument could be made for all plants to measure at the border because some plants have been incorporated into the ISO, there is no opportunity to measure at the border. SDG&E further believes that this unfair treatment could be a violation of interstate commerce clause since these plants would have to pay an additional two percent in compliance instruments. I was also glad to hear that this will be addressed in the 15-day comments from staff. Thank you for your time. (RASBERRY1)

> **Response:** In response to stakeholder comments and further evaluation, staff retained and clarified the use of the 1.0 loss factor. The use of the 1.0 loss factor must be demonstrated to be applicable and is subject to verification.

Calculating Specified Source Emission Factors

B-4. Multiple Comments: ***Data Sources for Calculation of Emission Factors for Specified Sources***

WPTF is concerned about an additional proposed change to section 95111(b)(2)(a) that would require CARB to use greenhouse gas (GHG) emissions data reported to the Energy Information Administration (EIA) rather than GHG data reported to the US Environmental Protection Agency as the basis for calculating emission factors for specified sources. The rationale for this change is not clear. WPTF considers GHG data reported to EPA to be more accurate than that reported to EIA and for this reason recommends that CARB continue to rely on EPA as the first source of GHG data for calculation of emission factors. For facilities that do not report to EPA, EIA GHG data may be used.

Staff has not indicated whether this proposed change is related to the recent regulatory advisory concerning updated emission factors. If CARB's concern relates to the timing of the availability/publication of EPA's GHG data, WPTF recommends that CARB simply used lagged data and calculate emission factors for each specified source in advance of the import year. The true emission rate of most facilities will not significantly differ year to year, thus use of a lag will not undermine the quality of the data. Additionally, this will provide more certainty to electricity importers regarding the associated carbon liability before undertaking the transactions. Since CARB already prospectively calculates the emission factors for asset controlling supplier, this change will better align treatment of all imports under the regulation. (WPTF1)

Comment: <u>**4. Change in method for calculating Emission Factors for specified out-of-state generating facilities §95111(b)(2)**</u>

In §95111(b)(2), ARB has proposed to change the methodology used to calculate emissions factors for specified out-of-state electricity generating facilities (EGFs), from factors based on GHG emission data reported to EPA under the federal Greenhouse Gas Emission Reporting Program pursuant to 40 CFR Part 98, to factors based on fuel data from the U.S. Energy Information Administration.

SCPPA Recommendation: SCPPA requests that ARB withdraw the proposed amendments.

1. Ensuring consistency between in-state and out-of-state emission sources, and from one year to the next, is important not only for purposes of measuring the changes in emissions over time, but also for the potential impacts on the Cap-and-Trade Program. In-state EGFs are required to report the same GHG emission data to ARB as they report to EPA under 40 CFR Part 98. Maintaining consistency in the emission calculation methodology for in-state and out-of-state EGFs ensures equal treatment of all EGFs. It is important that a tonne of in-state emissions is equal to a tonne of out-of-state emissions. Because emissions factors calculated using fuel data reported to EIA will be different than those calculated using GHG emission data reported to EPA, it would potentially create a competitive advantage or disadvantage for out-of-state EGFs in the Cap-and-Trade Program.

2. The current methodology for calculating emissions factors for out-of-state EGFs using GHG emissions data reported to EPA under 40 CFR Part 98 is necessary to satisfy the rigorous and consistent accounting of emissions requirement in AB 32. Unlike the fuel data reported to the EIA, GHG emissions based on CEMS data reported to EPA must pass rigorous quality assurance and quality checking standards.

3. Additionally, use of GHG emissions data reported to EPA may be required in light of the recent proposed EPA rule under Clean Air Act Section 111(d). Therefore, retaining the existing methodology will maintain consistency between the California and U.S. EPA programs. (SCPPA1)

Comment: SMUD suggests that ARB remove the proposed change to use EIA data to calculate emission factors for imported electricity from specified generating facilities. The MRR currently is based on reporting the same data to US EPA under 40 CFR Part 98 and to ARB under the MRR for Cap-and-Trade. If the ARB switches to emissions calculated based on EIA data there would be a discrepancy in the way out-of-state facilities and in- state facilities under the Cap-and-Trade are assessed, which could create an advantage for one group of resources over the other.

IV. SMUD Recommends Dropping Proposed Amendments Regarding Use of EIA Data To Calculate Certain Emission Factors

SMUD is concerned about the proposed change in § 95111(b)(2) to change the methodology used to calculate emissions factors for specified out-of-state electricity generating facilities (EGFs) to factors based on fuel use data from the U. S. Energy

Information Administration (EIA), rather than the current factors based on GHG emission data reported to EPA under the federal Greenhouse Gas Emission Reporting Program pursuant to 40 CFR Part 98. SMUD recommends removing this proposed modification.

In-state generating facilities are required to report the same GHG emission data to ARB as they report to EPA under 40 CFR Part 98. Cap-and-Trade obligations are based on this data. It is important to maintain consistency in the emission calculations between in-state and out-of-state power plants. Emission factors calculated using fuel data reported to EIA will be almost certainly be slightly different than those calculated based on the Part 98 data. This could create a competitive advantage or disadvantage one group of resources over the other in the Cap-and-Trade Program.

In addition, the current methodology for calculating emissions factors for out-of-state EGFs using GHG emissions is based on CEMS data reported to EPA with rigorous quality assurance and quality checking standards. This is necessary to provide rigorous and consistent accounting of emissions for the Cap-and-Trade structure, and it is unclear whether this rigor exists in the fuel data reported to the EIA. (SMUD1)

Comment: Use of EIA Data

In sections 95111(b)(2)(B) through (b)(2)(D), CARB is proposing amendments that would require the use of net generation data published by the Energy Information Administration (EIA) for determining specified source emission factors. According to the ISOR, this change is necessary to ensure the use of “unified and consistent data to determine emission factors across the sector.” (ISOR, p. 19) NCPA urges CARB to retain the use of the EPA data, and not adopt an additional agency’s calculations into the existing program. As a practical matter, NCPA’s members have some concerns with the timeliness and accuracy of the data produced by EIA. However, even without questions regarding the data’s veracity, it seems problematic to involve another reporting entity in the MRR calculations when CARB has already taken such pains to ensure that there is harmony between the California MRR and the EPA reporting requirements. Combined with the fact that California’s program will likely be even more inexorably linked with the federal EPA’s proposed rule after implementation of the Clean Power Plan Proposed Rule under sections 111(d) and (b), changes to the reporting metrics seems ill advised at this time. (NCPA1)

Comment: §95111(b)(2) - The existing methodology that uses EPA GHG emission data to calculate emission factors for out-of-state electricity generating facilities should be retained, to ensure that "a tonne is a tonne" for both in-state and imported electricity, and avoid creating a competitive advantage or disadvantage for out-of-state electricity generating facilities.

Method for calculating Specified Source Emission Factors for out-of-state electricity generating facilities [§95111(b)(2)]

<u>ARB Proposed Amendment</u>

ARB is proposing to change the source of GHG emission data used to calculate emission factors for electricity imported from specified sources as follows.

The Executive Officer shall calculate facility-specific or unit-specific emission factors and publish them on the ARB Mandatory Reporting website using the following equation:

$EF_{sp} = E_{sp} / EG$

Where:

E_{sp} = CO_2e emissions for a specified facility or unit for the report year (MT of CO_2e).

EG = Net generation from a specified facility or unit for the report year <u>shall be based on data reported to the Energy Information Administration (EIA)</u> reported to ARB under this section (MWh).

(A) For specified facilities or units whose operators are subject to this article or whose owners or operators voluntarily report under this article, E_{sp} shall be equal to the sum of CO_2e emissions reported pursuant to section 95112.

(B) For specified facilities or units whose operators are not subject to reporting under this article~~ or whose owners or operators do not voluntarily report under this article, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation~~, E_{sp} shall be based on GHG emissions reported to <u>the Energy Information Administration (EIA)</u>~~U.S. EPA pursuant to 40 CFR Part 98~~. Emissions from combustion of biomass-derived fuels will be based on EIA data~~, when not reported to U.S. EPA~~.

(C) For specified facilities or units whose operators are not subject to reporting under this article~~ or whose owners or operators do not voluntarily report under this article, nor are subject to the U.S. EPA GHG Mandatory Reporting Regulation~~, E_{sp} is calculated using heat of combustion data reported to ~~the Energy Information Administration (~~EIA~~)~~ as shown below.

$$E_{sp} = 0.001 \times \Sigma(Q \times EF)$$

Where:

0.001 = conversion factor kg to MT

Q = Heat of combustion for each specified fuel type from the specified facility or unit for the report year (MMBtu). For cogeneration, Q is the quantity of fuel allocated to electricity generation consistent with EIA reporting. For geothermal electricity, Q is the steam data reported to EIA (MMBtu).

EF = O_2e emission factor for the specified fuel type as required by this article (kg CO_2e /MMBtu). For geothermal electricity, EF is the estimated CO_2 emission factor published by EIA.

(D) Facilities or units will be assigned an emission factor by the Executive Officer based on the type of fuel combusted or the technology used when an ~~U.S. EPA GHG Report or~~ EIA fuel consumption report is not available, including new facilities and facilities located outside the U.S.

Analysis and Concerns

Under the existing rule language, GHG emissions for in-state and imported electricity are calculated using the same method specified in the U.S. Environmental Protection Agency (EPA) mandatory reporting rule, based on Continuous Emission Monitoring System (CEMS) data. The proposed amendment would change the emission calculation method for out-of- state electricity generating facilities to a fuel based method (using fuel data reported to the Energy Information Administration (EIA) and emission factors), while retaining EPA's emission calculation method for in-state generating facilities.

While ARB was developing its mandatory reporting rule in 2007, ARB staff evaluated the different emission calculation methods (CEMS and fuel based), and selected EPA's emission calculation method based on CEMS data as the method required for all in-state and out-of-state electricity generating units that are subject to federal regulation. This decision ensured that GHG emissions reported to ARB are consistent with GHG emissions reported to EPA, and that "a tonne is a tonne" for each reporting facility. That is why MRR 95111(b)(2) specifies use of GHG emissions reported to EPA pursuant to 40 CFR Part 98 to calculate emission factors for out-of-state generating facilities. Furthermore, CEMS data reported to EPA must pass rigorous quality assurance and quality control (QA/QC) checks; fuel data reported to EIA is not subject to QA/QC requirements.

The proposed amendment would create inconsistency between in-state and imported electricity, because GEMS and fuel-based emission calculation methods do not produce the same result. Under the proposed amendments, a tonne of GHG emissions reported for imported electricity would not be equivalent to a tonne of GHG emissions reported by in-state generating facilities. This inconsistency would create a competitive advantage or disadvantage for out-of-state electricity generating facilities under the Cap & Trade program, and unexpected increases in compliance costs for imported electricity.

Recommendations

LADWP recommends that ARB withdraw the proposed amendments and retain the existing method for calculating emission factors for specified out-of-state electricity generating facilities. This will ensure that the same emission calculation method (GHG emission data reported to EPA under 40 CFR Part 98, which is based on GEMS data) is used to report GHG emissions for both in-state and out-of-state electricity generating facilities.

Retaining the existing method will ensure rigorous and consistent accounting of GHG emissions for both in-state and imported electricity, and a level playing field under the cap & trade program for in-state and out-of-state electricity generating facilities. In addition, this will ensure consistency with previously reported GHG emission data and an apples-to-apples comparison for measuring changes in reported GHG emissions over the duration of the AB 32 program. (LADWP1)

> **Response:** Staff agrees with the commenters and has withdrawn the proposed amendments in the 15-day regulation. The final amendments require the use of US EPA Part 98 greenhouse gas reported data for developing the emission factors for out-of-state electricity generation facilities. This addresses stakeholder comments.

B-5. Multiple Comments: Good afternoon, Madam Chair and members of the Board. My name is Cindy Parsons with the Los Angeles Department of Water and Power. I'd like to start off by saying thank you to the staff for a favorable resolution on the issue with the emission factors for the specified imports and for reverting back to the EPA GHG emission data to ensure that a ton is a ton for both in-state and imported electricity. (LADWP2)

Comment: And likewise with regard to use of the EI – not use of the EIA data, as the case may be. So we would just like to express our appreciation to staff for working with us and our anticipation of continuing to work on these issues and resolving them in short order. Thank you. (BERLIN1)

Comment: Edison did not submit written comments, but as Dr. Tutt mentioned, I want to also thank staff for the work on this rule. In particular, we have been working were them quite a bit on the data sourcing issue, EPA versus EIA data, using EPA versus EIA data for the reporting. And in our case, this was a significant improvement and I believe correctly represented the generation from one of our plants in particular. So again, thanks for the effort by staff. And I think this just goes back to something I said earlier. And as we continue to have more experience implementing this rule, we're going to continue to find ways to improve it. It's been good to see we've been able to make these changes, these positive changes. Thank you very much. (SCE1)

> **Response:** Thank you for your support.

Meter Data Requirement

B-6. Comment: *Allocated generation from the Mid-C Hourly Coordination Agreement in lieu of meter data*

WPTF supports the clarification of the 'lessor of analysis' in section 95111(g)(1)(N). However, we request that CARB also include an explicit provision for mid-Columbia hydroelectric (Mid-C) resources to ensure that the regulation is consistent with the previous CARB guidance provided in March 2013[5] that allocated generation under the Mid-C Hourly Coordination Agreement will be accepted in lieu of meter data for these resources.

> (N) For verification purposes, retain meter generation data from all specified sources to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation:
>
> Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)
>
> Where:
>
> ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).
> MGsp = metered facility or unit net generation (MWh).
> TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

For the five hydroelectric resources located at the Mid-Columbia, allocated generation data under the Mid-C Hourly Coordination Agreement is required instead of meter generation data.

Additionally, we understand that the exemption for untagged power delivers would also apply to power that is deemed imported to California via the Energy Imbalance Market. We ask that CARB clarify whether this interpretation is corrected. (WPTF1)

> **Response:** Staff agrees that it provided guidance in March 2013 that states allocated generation under the Mid-Columbia Hourly Coordination Agreement (MCHCA) will be accepted in lieu of meter data for these resources. Staff confirms that this guidance is accurate and is supported by the regulatory text. Staff is committed to including the guidance referenced in this comment in any

[5] http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/epe_1pg.pdf

revised or updated guidance it releases related to meter data generation in early 2015. Staff also confirms that that the exemption for untagged power deliveries applies to EIM imports.

B-7. Comment: 1. Meter Data for Specified Imported Electricity §95111(g)(1)(N)

ARB's 45-Day Proposed Language: "For verification purposes, retain meter generation data from all specified sources to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation: ….."

SCPPA Proposed Revision:

"For verification purposes, retain meter generation data from all specified sources**, except for electricity supplied from an Asset Controlling Supplier's system,** 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~~ **unless the reporting entity is unable to obtain meter generation data for reasons beyond the reporting entity's control**. **In addition,** ~~This is applicable to~~ **for directly delivered** imports from specified sources for which ARB has calculated an emission factor of zero, and ~~for imports from~~ California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that ~~"count in full"~~ **qualify** under Public Utilities Code Section 399.16(d) **or California Code of Regulations Section 3202(a)(2)(A)**; (2) dynamically tagged power deliveries; (3) untagged power deliveries; ~~and~~ (4) nuclear power **and (5) large hydro power**, ~~. Accordingly,~~ a lesser of analysis is required pursuant to the following equation: …."

1. This proposed language addresses the concern that a reporting entity may not have the contractual right to hourly meter data under legacy power purchase agreements.

2. This proposed language clarifies the "lesser of" analysis is applicable only to directly delivered imports from non- exempted zero emission specified sources and RPS eligible resources that are not grandfathered.

3. This proposed language excludes large hydro power from the "lesser of" analysis as large hydro is not an intermittent resource and therefore there is no substitute energy involved. (SCPPA1)

Response: Staff declines to provide a blanket exemption for entities that are not able to retain meter generation data. Meter data generation is required to conduct the "lesser of" analysis, which is necessary to ensure that emissions associated with imported electricity are accurate and appropriately accounted for in the Cap-and-Trade Program. Instead, staff has provided specific exemptions for those situations in which hourly meter data is not available, such as in the case of asset controlling suppliers and certain hydroelectric facilities, which also addresses the commenter's other concerns.

B-8. Multiple Comments: §95111(g)(1)(N) - It is not possible to obtain generation meter data for all specified imports to verify that the power was generated by the facility or unit at the time it was directly delivered. This requirement should be limited to imported renewable energy that is subject to the lesser of analysis under the RPS regulations.

Meter Data for Verification of Specified Imports [§95111(g)(1)(N)]

ARB Proposed Amendment

ARB is proposing to modify an existing requirement to retain generation meter data for verification purposes, and require the meter data be used to calculate the lesser of the hourly meter or e-tag data for each hour.

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

***

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

***

(N) For verification purposes, retain meter generation data from all specified sources to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation:

Sum of Lesser of MWh = $\Sigma HMsp \min(MGsp, TGsp)$

Where:

$\Sigma HMsp$ = Sum of the Hourly Minimum of MGsp and TGsp (MWh).
MGsp = metered facility or unit net generation (MWh).
TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

Analysis and Concerns

ARB is endeavoring to incorporate the "lesser of' calculation from the California Renewable Portfolio Standard (RPS) regulations into the MRR. However, the proposed amendment is inconsistent with the 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.

ARB's proposed amendment would apply the "lesser of' calculation to electricity imported from an eligible renewable energy resource *as well as* other zero emission generating facilities, in order to subdivide hourly E-tags (delivered energy) into "specified" and "unspecified" by selecting the lesser of the hourly meter or E-tag data as specified and the remainder as unspecified. Applying the "lesser of' calculation to non-intermittent zero emission sources such as large hydro is not justified. Large hydro facilities produce only 100% specified energy, there is no "unspecified" substitute energy involved, so there is no reason to apply the "lesser of' calculation method.

It is unclear whether the first sentence "For verification purposes, retain meter generation data *from all specified sources* 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" applies to all specified sources of imported electricity, or only to zero emission and renewable energy sources. If retention of meter data is intended to apply to all specified sources, compliance may not be feasible. A reporting entity may not have the contractual right to hourly meter data under legacy power purchase agreements. In addition, meter data is not available for Asset Controlling Supplier power, a type of specified source. The consequence would be a non-conformance and a Qualified Positive verification statement, even if the rest of the report satisfies all the rule requirements.

Recommendations

The rule language needs to be clarified, to eliminate confusion over whether the requirement to "retain meter generation data from all specified sources 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 ' applies to all specified sources.

Also, 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.

Recommended Revisions to the Proposed Rule Language

To narrow applicability of this provision to only those sources where the "lesser of' analysis is required under the RPS regulation, LADWP recommends simplifying the rule language as follows:

> 95111(g)(1)(N) For verification purposes, retain meter generation data ~~from all specified sources to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full"~~ and perform a lesser of analysis for imported renewable electricity, that is directly delivered from a California Renewable Portfolio Standard (RPS) eligible resource into a California balancing authority, that is categorized as a Portfolio Content Category 1 under Public Utilities Code Section 399.16(d) or California Code of Regulations Section 3202(a)(2)(A); ~~(2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power.~~ Accordingly, ~~a lesser of analysis is required~~ pursuant to the following equation:
>
> Sum of Lesser of MWh = ΣHM_{sp} min(MG_{sp}, TG_{sp})
>
> Where:
>
> ΣHM_{sp} = Sum of the Hourly Minimum of MG_{sp} and TG_{sp} (MWh).
> MG_{sp} = metered facility or unit net generation (MWh).
> TG_{sp} = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh). (LADWP1)

Comment: The second is the use of meter data to verify specified imports. Almost a year ago, I spoke to you about the significant increase in administrative burden of having to compare hourly meter and ETech data to verify all specified imports per staff's interpretation of this provision. We do appreciate the proposal to narrow applicability of this provision. However, further clarification is needed to eliminate confusion over whether the requirement to retain meter data applies to all specified imports or just to those imports subject to the lesser of calculation. If the requirement applies to all specified imports and if meter data is not available, we're concerned that this could result in a non-conformance and a qualified positive verification statement. We recommend limiting this provision to only imported renewable energy that is subject to the lesser of analysis under the RPS regulations to be consistent with the CEC and the CPUC. (LADWP2)

> **Response:** The commenters ask whether the requirement to retain meter data applies to all specified imports or just to those imports subject to the "lesser of" calculation. In response to comments, the meter data requirement has been

moved from section 95111(g)(1)(N) to new subsection 95111(b)(2)(E), and the applicability of the requirement has been clarified. The requirement to retain meter data only applies to imports subject to the lesser of analysis.

B-9. Comment: PacifiCorp is concerned that the proposed modifications could be interpreted to prevent utilities from claiming firming and shaping transactions as part of the RPS Adjustment under the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms ("Cap and Trade Program"). Accordingly, PacifiCorp suggests clarifying the proposed modified section § 95111(g)(1)(N) as set out below.

PacifiCorp has been advised that the proposed modifications to the Mandatory Reporting Rule are not intended to modify or eliminate the RPS Adjustment as it may be claimed under § 95852(b)(4) of the Cap and Trade Program. However, a potential for confusion arises because § 95852(b)(4) uses the words "eligible renewable energy resource," a concept to which the amended reporting requirement also refers, but to which § 95852(b)(3), regarding specified source imports, does not. Therefore, as the amended reporting requirement caps reportable imports at generation within any particular hour, it could be read as capping firming and shaping at the generation of a particular hour of import of the substitute energy, even though <u>no</u> §95852(b)(4) RPS Adjustment energy is being directly imported pursuant to §95852(b)(4)(D). Capping the amount of generation required to be reported to the amount generated within a particular hour from a generator that is not directly delivering that energy would nullify the concept of firming and shaping and therefore also California Renewable Portfolio Standard product content category two transactions. Firming and shaping would be nullified because the very nature of firming and shaping is the delivery of energy that was generated in one hour in a different hour. As an example, a firming and shaping transaction could include a 5 megawatt geothermal resource firming and shaping a month's generation into a single eight hour 450 megawatt schedule on the last day of the month. However, the proposed language could be read as limiting such a transaction to the 5 megawatts per hour of actual resource generation during that eight hour delivery period.

To make it clear that the proposed modifications do not refer to the §95852(b)(4) RPS Adjustment, PacifiCorp proposes additional revisions to the proposed modification to § 95111(g)(1)(N) of the Mandatory Reporting Rule. The currently proposed revisions are shown in underline, while PacifiCorp's proposed revisions are shown in bolded double underline and strike-out. The clarifying language below is designed to retain the current method (i.e., based on reporting year) of calculating the RPS Adjustment.

> (N) For verification purposes, retain meter generation data <u>from all specified sources</u> 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. <u>This is applicable to imports from specified resources</u> <u>**under § 95852(b)(3) of the cap-and-trade regulation**</u> <u>for which ARB has calculated an emission factor of zero, and for imports from California</u>

Renewable Portfolio Standard (RPS) eligible resources **under § 95852(b)(4) of the cap-and-trade regulation**, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a less of analysis is required pursuant to the following equation:

Sum of Lesser of MWh = $\Sigma \cancel{H} M_{sp}$ min(MG_{sp}, TG_{sp})

Where:

$\Sigma \cancel{H} M_{sp}$ = Sum of the ~~**Hourly**~~ Minimum of MG_{sp} and TG_{sp} (MWh)**,** ~~.~~ **calculated hourly in the case of specified sources claimed under §95852(b)(3) of the cap-and- trade regulation and calculated for the reporting year for purposes of the RPS adjustment calculation under §95852(b)(4) of the cap-and-trade regulation.**
MG_{sp} = metered facility or unit net generation (MWh).
TG_{sp} = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh). (PCORP1)

Response: The commenter is concerned that the proposed meter data requirement language would prevent an entity from claiming any over-generation amounts, relative to scheduled values, as an RPS Adjustment. This is not the case. For example, if an entity schedules 100 MW in a given hour, but the unit actually generates 110 MW, the commenter contends that they should be able to take an RPS Adjustment for the extra 10 MW that cannot be imported to California. Over-generation amounts, relative to scheduled values, are eligible to be claimed as RPS Adjustments, assuming all other applicable requirements are met.

In addition, the concern expressed by the commenter, that the proposed meter data requirement language would somehow cap generation associated with firming and shaping contracts, is misplaced. The concerns raised by the commenter have been addressed by moving the meter data requirement from section 95111(g)(1)(N) to new subsection 95111(b)(2)(E). By moving the requirement, it will be clearly associated with certain specified source import claims, not with RPS Adjustments.

B-10. Multiple Comments: *The proposed change to the MRR structure that would include in MRR§ 95111(g)(1)(N) a requirement to perform a "lesser of" calculation for certain specified resources.* SMUD remains opposed to this requirement in general, but appreciates the continued narrowing of application apparent in the proposed text for §95111(g)(1)(N). SMUD recommends at least additional narrowing, if not complete removal, of this proposed policy, and provides a rationale for our proposal below.

I. SMUD Recommends Removal of or Alternative Language for New Meter Data Reporting And Subsequent Calculations For Specific Resources

ARB staff proposed new language in § 95111(g)(1)(N) to clarify existing requirements about what is supposed to happen with hourly meter generation data that is currently required to be retained for verification purposes. The new language (shown below) indicates that for certain resources 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.

> *(g) Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment.*
>
> ***
>
> *(1) Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment. The following information is required:*
>
> ***
>
> *(N) For verification purposes, retain meter generation data <u>from all specified sources</u> to document that the power claimed by the reporting entity was generated by the facility or unit at the time thepower was directly delivered. <u>This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation:</u>*
>
> *<u>Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)</u>*
>
> *<u>Where:</u>*
>
> *<u>ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).</u>*
>
> *<u>MGsp = metered facility or unit net generation (MWh).</u>*
>
> *<u>TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).</u>*

(A) SMUD's Recommendation and Suggested Language. SMUD appreciates the ARB staff's attempt to clarify this requirement. The "lesser of" calculation has not previously been required in the text of the MRR, but has been addressed and requested in various reporting guidance documents or templates with some ambiguity. The revised proposed language significantly narrows of the application of the “lesser of” structure from prior expectations in GHG reporting, but SMUD does not think that the proposed clarification yet gets this right.

SMUD continues to recommend that the ARB completely remove the requirement for a “lesser of” analysis in the MRR. We believe that the “lesser of” analysis merely adds complication and administrative burden without any commensurate benefit in terms of accuracy of GHG reporting or ability to verify such reports. If the rationale is to match the “lesser of” analysis required by the CEC and the CPUC for certain resources in California’s 33% RPS, then the proposed language will not achieve this purpose because the proposed language distinguishes between renewable and fossil emissions, whereas the structure in the RPS arena is intended to distinguish between types of renewables. However, if ARB desires to maintain the “lesser of” structure several issues should to be addressed.

First, while the proposed language is more closely aligned with the CEC/CPUC “lesser of” analysis for the RPS, it still does not achieve the purpose of matching the CEC/CPUC structure. The language attempts to reach that match by enumerating specific types of specified resources that are excluded from the “lesser of” analysis requirement. As virtually all specified source resources are excluded, this is cumbersome. A better structure would simply list the specified source resources to which the analysis would apply to match the CEC/CPUC treatment.

Second, the proposed “lesser of” language is misplaced in § 95111(g)(1) because the operational data requested in new paragraph (N) would not be available to meet the reporting deadline there. Subsection (g)(1) of § 95111 is aimed at prior registration of specified sources, with data due by February 1st of each year, so that emission factors can be determined and provided for these sources for the full reporting later in the year. Parts (A)-(L) in § 95111(g)(1) request “static” information -- not dependent upon any operational data from the previous year. Operational data is not fully available by February 1st, hence the proposed “lesser of” analysis cannot be accomplished in the timeframe expected in the proposed regulations. The same constraint applies to §95111(g)(1)(M), which refers to the status of RECs for the previous year – this information is not fully available by the due date. SMUD suggests that both §95111(g)(1)(M) and (N) be moved in the regulation to be separate requirements in §95111(g), as shown as (g)(6) and (g)(7) below, to meet a June 1st reporting date.

Third, in addition to specified sources that are directly delivered, subsection (g)(1) of § 95111 also requests prior registration information for resources that will require use of the RPS adjustment. It is SMUD’s understanding from discussions with ARB staff that the “lesser of” analysis is not intended to apply for resources needing the RPS Adjustment, yet there remains apparent confusion about this amongst market entities, in part because § 95111(g)(1) applies to both types of resources. The proposed language attempts to address this confusion by including language that limits the “lesser of” analysis just to "specified sources". This is another reason to remove the language from this subsection to a place where it is less confusing.

Fourth, it is unclear from the proposed language how the proposed "lesser of" analysis should affect emission factors used in mandatory reporting. The implication is that the specified source emission factor would only be used for the generation that results from the "lesser of" calculation, but this is not explicitly stated by the language. Nor is there clarity in the proposed language about what emission factor should be used for the remaining generation that is scheduled into California. It may seem reasonable to use the "unspecified" emission factor for this remaining generation, but this is not explicitly stated. If that is the expectation, there is a potential mismatch with CEC/CPUC RPS policy, since in that structure the "lesser-of" analysis does not divide between zero-emission renewable and unspecified emitting resources, but rather between "categories" of zero-emission renewable sources. If the ARB handles this potential discrepancy by allowing the "RPS adjustment" to be used to offset the associated emissions from the generation excluded by the "lesser of" analysis, there is a potential conflict with the MRR and Cap and Trade regulations, since the emissions are associated with energy from directly delivered specified sources, while the "RPS Adjustment" is clearly limited to renewable sources that are NOT directly delivered.

SMUD is suggesting the following language to "cure" the issues discussed above, with comments and redline/strikeout edits:

> *(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. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to subsection 95111(g)(2)-(~~5~~7) 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 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.*~~

~~*(N) For verification purposes, retain meter generation data from all specified sources to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to the following equation:*~~

~~*Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)*~~

~~*Where:*~~

~~*ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).*~~

~~*MGsp = metered facility or unit net generation (MWh).*~~

~~*TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).*~~

(6) Additional Information for Renewable Specified Sources. Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the:

(A) RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and document whether or not the RECs have been placed in a retirement subaccount.
(B) For verification purposes, retain meter generation data when available from all imported specified sources that meet the requirements of Public Utilities Code 399.16(b)(1)(A) 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. For these resources, a specified source emission factor only applies to the amount of generation calculated by the following equation:

Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)
Where:
ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh).
MGsp = metered facility or unit net generation (MWh).
TGsp = tagged or transmitted energy at the transmission or
sub-transmission level imported to California (MWh).

Any remaining generation should use the unspecified emission factor and is considered not directly delivered and eligible for RPS adjustment treatment.

(7) Additional Information for RPS Adjustments. Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the:

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.

If the ARB insists on including a "lesser of" analysis, but is unable at this stage of the regulatory process to make all of the changes recommended for easing confusion and adding consistency, SMUD suggests the following changes to the proposed modifications, and recommends that the ARB provide guidance to clarify the other issues described above until they can be addressed in the regulations:

(N) For verification purposes, retain meter generation data when available from all specified sources that meet the requirements of Public Utilities Code 399.16(b)(1)(A) to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. ~~This is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) grandfathered contracts under the California RPS program that "count in full" under Public Utilities Code Section 399.16(d); (2) dynamically tagged power deliveries; (3) untagged power deliveries; and (4) nuclear power. Accordingly, a lesser of analysis is required pursuant to~~ For these resources, a specified source emission factor only applies to the amount of generation calculated by the following equation:

Sum of Lesser of MWh = ΣHMsp min(MGsp, TGsp)

Where:

ΣHMsp = Sum of the Hourly Minimum of MGsp and TGsp (MWh). MGsp = metered facility or unit net generation (MWh).

TGsp = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

Any remaining scheduled energy should use the unspecified emission factor and is considered not directly delivered and eligible for RPS adjustment treatment.

A. SMUD's Initial Statement of Reasons: As stated above, SMUD recommends complete removal of the "lesser of" analysis proposed by ARB staff for the following reasons. We believe that the proposed "lesser of" analysis merely adds complication and administrative burden without any commensurate benefit in terms of accuracy of GHG reporting or ability to verify such reports. The proposed language:

- Does not match CEC/CPUC RPS policy
- Is inconsistent with market scheduling and tracking processes
- Is inconsistent with other MRR and Cap and Trade rules and definitions
- Provides no improvement in emission reporting accuracy

Mismatch with CEC/CPUC RPS Policy: The CEC and CPUC have interpreted SBX1 2 to mean that certain specific renewable contracts must be tracked/verified on an hourly basis. However, this policy only applies to eligible renewable contracts signed after 6/1/2010 from resources that are located outside of CA (generally) and where the power is "directly scheduled" into California, without either using substitute power explicitly or being dynamically scheduled. The proposed language appears to attempt to match this policy, although in a seemingly confusing manner, and with the clear mismatch of also applying to specified large hydro sources.

In addition, even when the resources subject to the ARB GHG "lesser of" policy are the same as the resources subject to the CEC/CPUC RPS "lesser of" policy, the end result may end up being inconsistent with without further changes to the ARB proposal. The CEC/CPUC "lesser of" policy has the intent of dividing between two "types" of renewable generation to be counted. The CEC/CPUC "lesser of" total is deemed "product content category 1" (PCC1), while any scheduled power above this total is deemed to be either a "product content category 2" (PCC2) or "product content category 3" (PCC3) resource, depending on contract specific circumstances (this remainder will almost certainly be considered PCC3 by the CEC). The point here is that ***all*** of the scheduled power is deemed renewable under the RPS, even when the "lesser of" analysis yields a smaller number. It is unclear in the proposed regulations, but it would appear from previous discussions with ARB staff, that the proposed ARB policy would result in a "lesser of" total that would be deemed to have specified source emissions (zero-GHG renewable), while any scheduled import above this total would presumably acquire a default emissions factor.

Hence, there could be a situation where the CEC/CPUC are counting imported power as "renewable", but the ARB is imposing a default emissions factor for this same power. This normally is accounted for under the Cap and Trade Program by using the "RPS Adjustment", and that may be feasible here as well, but it would seem that such use of the RPS adjustment would require further changes in MRR and the Cap and Trade regulations to clearly allow this treatment (see below for more discussion of the potential inconsistency and complications with MRR/C&T regulations and the proposed policy).

Inconsistent with Market Scheduling and Tracking Practices: Commercial transactions are typically structured with monthly or even annual reconciliation of contracted-for and transmission-scheduled imported power, in contrast to the hourly "reconciliation" envisioned by the proposed MRR policy. The CEC's policy to reconcile certain, limited renewable transactions on an hourly basis also suffers from this problem, but it has limited application and the CEC believes that they are required by SBX1 2 to follow this path. The ARB has no similar legal language to interpret as a potential requirement its hourly reconciliation proposal.

For the California RPS, renewable generation nearly always must be tracked in the Western Regional Energy Generation Information System (WREGIS). This tracking occurs through WREGIS "certificates", with each "certificate" (essentially a REC) representing a MWh of renewable generation. These certificates are created, held, moved from one account to another, and retired with reference to the month of generation, not the hour. Hourly generation is ***not*** tracked in WREGIS, only monthly generation. Hence, the CEC/CPUC policy has required creating a tracking structure outside of WREGIS to consider hourly generation versus scheduled data, which will then presumably be used to divide the monthly WREGIS numbers into different "categories" of renewable generation.

Non-renewable, but zero-emission, generation is not tracked in WREGIS, but reconciliation of what is generated versus what is actually delivered (via e-tags) is typically done on a monthly basis. While it is true that e-tags are hourly, market transactions are normally not reconciled on an hourly basis, allowing for typical small differences between actual generation and transmission-scheduled power to "factor out" over time. This allows baseload generating facilities to be procured and scheduled across transmission lines without either: 1) suffering the transaction costs of accounting for minor differences between the generation and the scheduled amounts, or 2) using up space on the transmission system by overscheduling to insure receiving the full amount of contracted generation.

What this comes down to for the importer is usually a monthly import total from a specified source that is simply the sum of the hourly e-tags. The importer ***in most cases does not have access to the metered generation data***, nor do they perform any hourly "matching" or "true-up" procedures – they simply verify that they are getting the delivered amounts, properly "tagged", as per contract. Importers do not normally see or participate in the reconciliation between tags and generation. This reconciliation happens between the generator and their respective balancing authority to account for any small hourly deviations.

In addition, some contracts are not for the entire output for a particular generator. In these cases, just like with full-output contracts, the contracting party simply depends on the proven, scheduled, delivery of the contracted amount of power, verified by e-tags. As usual, ***the importer or contracting party will not normally have access to or rights to information about the metered generation from the facility, particularly in cases where a portion of the generation is being sold/used by some other party***. Here, there is no market or contractual reason for the importing party to have knowledge of what the total amount of generation from a particular facility is, or where any generation beyond that contracted for goes, on any timeframe. All that really matters is that the contracted-for generation amount is scheduled as per agreement, which is verified by the schedule e-tags. ***In general, SMUD believes that ARB should avoid requesting information from importers that they do not normally have as part of market transactions.***

Finally, it is unclear exactly how the ARB policy being proposed (or the more limited CEC policy, for that matter) would apply to "multi-fuel" facilities. The hourly metered generation from these facilities may or may not correspond well to annual renewable totals being determined and used. Generally, a facility can use up to 2% fossil fuels and have all the generation counted by the RPS as renewable, above that percentage, only the renewable portion counts. This is, SMUD believes, determined on an annual basis – certainly not on an hourly basis.

Inconsistent with MRR and Cap And Trade Rules: It is unclear in the proposed text exactly how emissions would be attributed to power remaining from the "lesser of" calculation. However, previous discussions with ARB staff suggested that the RPS Adjustment could be used to, in effect, restore the zero-emissions aspect of the imported power falling above the "lesser of" total. If that is the concept, it appears to be inconsistent with the definitions and rule requirements in the MRR and Cap and Trade regulations, requiring ARB to either make modifications to these definitions and rules or suggest in guidance that they be used for hourly reconciliation even though inconsistent.

For example, the MRR and Cap and Trade regulations define substitute power as:

> "Substitute power" or "substitute electricity" means electricity that is provided to meet the terms of a power purchase contract with a specified facility or unit **when that facility or unit is not generating electricity. [emphasis added]**

This is consistent with a typical use of substitute power, for a "firmed and or shaped" contract, where the scheduled power from a contract comes in hours when a facility is not generating. However, the proposed ARB "lesser of" policy appears to imply use of the "substitute power concept" in hours where a specified facility or unit is generating electricity almost as expected, but not exactly at the level in the hourly import schedule for the contract. This seems inconsistent with the definition of "substitute" power in the regulations.

Also, the Cap and Trade regulations in § 95852 (b)(4)(D) state regarding the RPS Adjustment requirement:

> (D) No RPS adjustment may be claimed for an eligible renewable energy resource when its electricity is directly delivered.

However, the proposed ARB hourly reconciliation policy applies, as SMUD understands it, only to specified source imports that are directly delivered. If the RPS Adjustment is contemplated for use here, it would seem that ARB staff and obligated entities would be using the RPS Adjustment in a manner inconsistent with the Cap and Trade regulations. In addition, this use of the RPS Adjustment is clearly different than the typical use, which requires RECs tabulated on an annual basis to determine an adjustment to emissions imported from entirely different sources, even in entirely different years than the underlying renewable generation.

No Real Improvement in Reporting Accuracy: SMUD understands from discussions with ARB staff that one rationale for the proposed "lesser of" hourly reconciliation policy is to achieve greater accuracy in reporting of emissions from imported power. The logic goes that in hours in which the scheduled import is *greater than* the specified source generation, the imported power is only partially from the specified source, with the remainder from an unspecified, default or "system" source. On the other hand, in hours where the scheduled import is *less than or equal to* the specified source generation, the imported power is fully from the specified source, but any excess generation in that hour is not imported to California, but normally used in the system where the generator is located. This leads to the concept that the accuracy of reported emissions from imports may be improved by hourly reconciliation as proposed by MRR staff -- by using the default emissions factor rather than the specified source factor to account for the emissions associated with the unspecified or "system" power in those hours where specified generation is less than scheduled. However, in reality, this policy is likely to only provide a false sense of improving the precision of identifying which sources are contributing in certain hours, while likely decreasing the overall accuracy of the imported emissions picture.

The default emission factor is a broad reflection of system or unspecified emissions over a timeframe of multiple years from systems outside of California in general, not an accurate measure of unspecified source emissions in any particular hour from any particular location. This works fine to attribute emissions to unspecified imports in general, particularly in the absence of a specified source being part of a particular transaction or contract (that is, a straight up purchase of unspecified power). It may be appropriate to update this factor periodically, to reflect changes in sources that have been specified in contracts, and hence removed from the "unspecified" mix.

In reality, there will be a highly variable mix of resources contributing to unspecified imports from a particular location on an hourly basis. Hence, using the default emission factor as it stands for the partial "system" or unspecified generation in those hours where the generation from an actual specified source is less than scheduled is in effect using a relatively constant approximation for the likely highly varying unspecified emissions from that location in those hours. We use a relatively constant, high-level default emissions factor because it would be problematic for the market to have a frequently varying default emissions factor for imports (not to mention cost-prohibitive, if not impossible).

In an individual case where a specified source is newly contracted for and imported to California, it alters the emissions that would come from any remaining, unspecified power in the system where the source is located, but we do not and should not change the default emissions factors to reflect this. The emissions from this remaining, unspecified, power also vary from hour to hour (and minute to minute), depending on what resources are generating in that hour (or minute) in the system, what resources are on the margin, and what other resources have been “tied up” already in specified contracts. But again we use a constant, high-level default emissions factor.

Examining what happens in reality to actual emissions on an hourly basis when a specified source generates more or less than scheduled leads to the conclusion that overall accuracy is not improved by using the default emissions factor for a portion of the specified generation in any hour. More specified source generation than scheduled will contribute more to the overall emission profile of a system than expected, and vice versa when generating less, all else being equal. A theoretical, completely “accurate” calculation would adjust the remaining system emissions based on the metered generation of the specified source. So, in this hypothetical structure, if we look at an hour in which a zero-emissions specified source is generating less than the scheduled amount, the remaining emissions would presumably be higher, reflecting the lower than expected generation from that zero-emission specified source in that hour. In an hour when the zero-emissions specified source is generating more than scheduled, the greater-than-expected (but not imported) generation from that source would tend to reduce the remaining emissions in the system in that hour. Hence, assigning a portion of the scheduled specified source import for an hour to unspecified power using the constant default emissions factor does not appear to improve emission reporting accuracy, and may in effect distort the overall picture of imported emissions. It is more accurate to simply use the specified source emission factor for all scheduled power, without a “lesser of” hourly reconciliation. (SMUD1)

Comment: Good afternoon, Chair Nichols and members of the Board. I want to start, as many do, by thanking staff for the work that's gone on on some of these issues over the last year. As Cindy Parsons from LADWP mentioned, we've been talking to staff about some of these issues for over a year. And, I wanted to particularly focus on the lesser of hourly meter generation requirement. I think a year ago we were worried that that was applying to all specified source imports of any type basically. And the narrowing has now I believe gotten it down with further potential language changes to only matching the similar lesser of analysis that the Energy Commission requires for certain categories of renewable resources. So we're already having to do that analysis for the Energy Commission. I still wonder why we would have to do it here as well because at the Energy Commission it's dividing up between two kinds of renewables. And here, it seems like what we'd be looking at is only -- we would be dividing up between a renewable and an unspecified source with an emission factor. And then potentially have to go and calculate an RPS adjustment for that one remainder of the division. So that's one question or issue I still have with this.

And the second is in SMUD's case, we have one contract in which this applies for which we don't get all of the generation. We only contract for a portion of it. And in that particular case, as I think many commenters have pointed out, the whole lesser-of calculation is kind of moot because it will always be the scheduled amount that is the lesser of. We are going through the exercise, but it won't make any difference in any of the underlying calculations. But I appreciate the narrowing, and I'm glad we're going to have some further talk on 15-day language to further consider some of these issues. And we're working good with staff on it. So thank you. (SMUD2)

> **Response:** Under MRR, greenhouse gas emissions are reported to ARB. Under the RPS Program, publicly-owned utilities (POU), like SMUD, report megawatt-hours of renewable power to the CEC. However, a CEC report on renewable power is not a viable substitute for similar, but related, reporting requirements under MRR.
>
> The commenter states that a lesser of analysis is moot because the metered output from the renewable resource will always equal the scheduled amount. This is not correct. In a lesser of analysis, the metered generation amount in each hour is compared with the scheduled transmission value, and only the lesser of the two can be claimed as imported, directly delivered power to California. Consider an Oregon wind project that only generates 85 MW in a given hour, but 100 MW is scheduled for that hour on a single NERC e-tag. Because only 85 MW was generated and 100 MW is scheduled, an additional 15 MW must be obtained to meet the scheduling requirement of the e-tag. This additional 15 MW will typically be provided by the Transmission Provider (TP) and would typically consist of unspecified power from the host balancing authority area, which must be separately reported under MRR. While 100 MW is directly delivered to California during that hour, only 85 MW can be claimed as zero emission power, whereas the remaining 15 MW must be claimed as unspecified power.

B-11. Comment: Meter Data Retention

The proposed amendments would change section 95111(g)(1)(N), and add a new data retention and verification requirement. This requirement comes under the section titled "Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment." The proposed amendments to this section would require reporters, for verification purposes, to: (1) retain meter generation data from all specified sources, and (2) include a new equation that reporters must use to determine the amount of generated and scheduled power that can be reported as specified source power. The intent is to accurately report the amount of power that can be reported as specified power, if there is a difference between the amount of electricity generated within an hour, and the amount of electricity scheduled or metered into a California balancing authority within that same hour. The ISOR states that this is necessary because there "could be situations where a renewable source, which may not have a compliance obligation, is scheduled, but not actually delivered to California. For the integrity of the Cap-and- Trade Program, it is important to accurately assign compliance obligations on actual delivered electricity." (ISOR, p. 20) While NCPA does not disagree that it is important to have accurate data, the placement of this new provision causes confusion regarding the scope of the required data. While Staff has confirmed that the information at issue is not applicable to use of the RPS adjustment, due to the fact that the proposed amendments are placed in section 95111(g)(1), the requirement would appear to also cover the RPS adjustment. NCPA understands that Staff is reviewing the regulation and working with stakeholders to better describe application of the required information or move the requirement to a different part of the regulation. The Board should direct that these clarifications be reflected in 15-day changes prior to approving the proposed amendments. (NCPA1)

> **Response:** For clarity, and in response to stakeholder comments, the proposed language has been moved from section 95111(g)(1)(N) to new subsection 95111(b)(2)(E) because it is a provision associated with specified source imports. In addition, six exclusions from this requirement have been added to more clearly define its applicability.

CAISO Sales Requirements

B-12. Multiple Comments: 2. Potential New CAISO Market Sales Reporting Requirements Under §95111(a)(12)

ARB's 45-Day Proposed Language: *"Electrical Distribution Utility Sales into CAISO. All electricity distribution utilities except IOUs must report the annual MWh, by source, of all electricity sold in the CAISO market, and the emission factor for each source, beginning with calendar years 2013 and 2014, reported in 2015."*

SCPPA Proposed Revision:

"Electrical Distribution Utility Sales into CAISO. ~~All~~ **Except for (a) IOUs and (b) POUs that consign all their allocated allowances for auction and attest that no auction proceeds will be used to meet compliance obligations associated with sales into the CAISO markets,** electricity distribution utilities ~~except IOUs~~ must report the annual MWh, by source **or system as specified on the NERC E-tag**, of ~~all~~ electricity sold in the CAISO market **per the CAISO tariff**, and the emission factor for each source **or system as applicable**, beginning with calendar years 2013 and 2014, reported in 2015.

> 1. This proposed language exempts POUs that consign 100% of their allocated allowances to auction and do not use any of the auction proceeds to meet compliance obligations associated with electricity sold into the CAISO. The attestation eliminates the verification process to address ARB staff's stated concern that third party verifiers are not allowed to verify POU's allowance positions.
>
> 2. This proposed language specifically references the CAISO tariff.
> 3. This proposed language provides the flexibility to report by source (for POUs within CAISO) or in aggregate (for
> POUs outside the CAISO) and by source specific emission factor or system average emission factor.

3. <u>Add definition of Electricity Sold in the CAISO Market</u>

For clarity, the Mandatory Reporting Regulation should include a definition of electricity sold in the CAISO market.

SCPPA Proposed Definition:

<u>Electricity Sold in the CAISO Market</u> **<u>means any transaction that is financially settled by the CAISO under the CAISO tariff, where the California Independent System Operator (CAISO) is the contracting counterparty, except for the exclusions specified in Section 11.29 of the CAISO tariff.</u>** (SCPPA1)

Comment: M-S-R urges the Board to direct that the proposed amendments be revised to: (2) tailor the requirements for EDU reporting of annual sales into the CAISO to entities that do not consign all of their freely allocated allowances into the limited use holding account, limit the applicability to electricity not covered by section 11.29 of the ISO tariff, and clarify the use of emissions factors for system power;

Section 95111(a)(12) – Reporting Sales Into the CAISO

In order to verify that freely allocated allowances are used only for purposes authorized under the Cap-and-Trade Regulation, the proposed amendments would require reporting of "sales into the CAISO." As a threshold matter, before applying a reporting requirement to "sales into the CAISO," CARB must define what these transactions are. Consistent with the recommendations of both the Northern California Power Agency and the Southern California Public Power Authority, M-S-R believes that the definition should specifically exclude transactions that are "self scheduling" as defined in section 11.29 of the CAISO tariff, since these transactions are not sales, and therefore, not subject to the restrictions in section 95892(d)(5). Accordingly, M-S-R urges the Board to direct 15-day changes to the proposed amendments that include the following definition for "sales into the CAISO":

> **"Electricity Sold in the CAISO Market means any transaction that is financially settled by the CAISO under the CAISO tariff, where the California Independent System Operator (CAISO) is the contracting counterparty, except for the exclusions specified in Section 11.29 of the CAISO tariff."**

For purposes of determining the applicability of this newly proposed reporting requirement, M-S-R urges CARB to exclude POUs and Electrical Cooperatives that place all of their freely allocated allowances into their limited use holding accounts for consignment to auction. This distinction would place the non-IOU EDUs that do not put freely allocated allowances into their compliance accounts into the same reporting obligation as the IOUs. Furthermore, this could be confirmed and verified each year without the release of confidential or proprietary information, and without adversely impacting the auction markets. The proposed amendment should also be revised to reconcile the use of the terms "Electrical Distribution Utility" and "Electric Power Entity."

The definition for “electrical distribution utilities” found in the Cap-and-Trade Regulation should be added to the MRR, and the provisions of proposed § 95111(a)(12) should reflect the difference between the two terms. Accordingly, M-S-R recommends that the following clarification be added to the proposed amendment:

> **“Electrical Distribution Utility Sales into CAISO. Electric power entities that are ~~All electricity~~ electrical distribution utilities~~,~~ except for (a) IOUs and (b) POUs that consign all their allocated allowances for auction,…”**

M-S-R has also observed that there are no provisions in the regulation to calculate non-facility- specific or non-unit-specific emission factors for sources in California. Entities such as M-S-R’s members sell electricity from their “system,” not from a specific generator or generation facility,[6] similar to the manner in which electricity is often imported into California. However, the default emissions factor for unspecified power in § 95111(b)(1) seems to apply to electricity imports only, and would not appear to apply to in-state resources. Changes are needed to address this issue, although it presents complexities that are not easily explained or clarified in regulatory language. M-S-R has been in discussions with CARB staff regarding this matter, and is encouraged that a solution can be crafted. Accordingly, M-S-R asks that the Board recognize the need for this clarification and direct that 15-day changes be worked out with staff and stakeholders. (MSR1)

Comment: §95111 (a)(12)- This proposed amendment would require electricity distribution utilities to " ...report the annual MWh, by source, of all electricity sold in the CAISO market, and the emission factor for each source ..." This requirement should be modified to allow utilities to report either by source or by system, to accommodate differences between utilities within and outside of the California Independent System Operator (CAISO) balancing authority . Without the ability to report by system, LADWP is concerned that the uncertainty involved in estimating an individual source of electr icity from within a utility's system may adversely affect the verification statement for the entire Electric Power Entity report. Also, this reporting requirement should be limited to electricity where the reporting entity is the First Deliverer, as defined in the MRR, since there is no compliance obligation on electricity that is re-sold within California.

Reporting of Electricity Sold into the California Independent System Operator (CAISO) market [§95111(a)(12)]

ARB Proposed Amendment

ARB is proposing to add the following new requirement to the Electric Power Entity report:

> 95111(a)(121) Electrical Distribution Utility Sales into CAISO. All electricity distribution utilities except IOUs must report the annual MWh, by source, of all

[6] Examples shown on REU e-tags are REDDR1 (Redding), SMUDSYS (SMUD system), TID.System (Turlock Irrigation District), and RSVL (Roseville system).

electricity sold in the CAISO market, and the emission factor for each source, beginning with calendar years 2013 and 2014, reported in 2015.

This proposed amendment is related to the prohibition on the use of GHG emission allowances in section 95892(d)(5) of the Cap & Trade regulation. The intent is to ensure that Publicly Owned Utilities (POUs) purchase a sufficient number of GHG emission allowances to satisfy the compliance obligation associated with electricity sold into the CAISO wholesale electricity market.

Analysis and Concerns:

1. Alternative Reporting Methods to Allow for Differences among POUs: There is no one- size-fits-all method for determining electricity sold in the CAISO market that is suitable for all utilities. Differences among the utilities should be recognized and accommodated. A method appropriate for POUs within the CAISO balancing authority may not work for POUs outside of the CAISO balancing authority. For example, POUs within the CAISO use an hourly resource stacking method to determine net sales into the CAISO, so it is feasible for them to estimate emissions from individual generating resources. However, for POUs outside of the CAISO that sell power from their system rather than from a specific generating facility or unit, the only way to accurately estimate emissions associated with electricity sold into the CAISO would be to use an overall system average emission factor. The rule language should be modified to allow utilities to report either by source or by system.

2. Complexity of Estimating GHG Emissions for Wholesale Sales: Determining the mega- watt hours (MWh) of electricity sold in the CAISO wholesale electricity market is fairly straightforward. However, estimating emissions associated with those sales is complex. Electricity generated by POUs can go to serve native load or wholesale sales. For POUs outside of the CAISO that have a diverse portfolio of generating resources, it can be difficult to estimate which generating resource(s) supplied electricity for the wholesale sale. If a POU is also a balancing authority (such as LADWP) that uses its internal generating resources to support transmission losses and balance the system, it can be extremely complicated.

3. Verification Concerns: For POUs outside of the CAISO, the ability to report by system is essential. Without this option, the complexity and uncertainty involved in estimating a source of electricity within their system that supported the wholesale sale may result in an Adverse Verification Statement for the entire Electric Power Entity report.

4. First Deliverer only : Since the purpose of this reporting requirement is to ensure that POUs purchase sufficient GHG emission allowances to cover the compliance obligation for electricity sold into the CAISO market ,

electricity that was generated by a different entity, purchased by the POU and then resold into the CAISO should be excluded under this reporting requirement. The First Deliverer of the electricity is responsible for the compliance obligation. There is no compliance obligation on electricity that is re-sold within California. Therefore, this reporting requirement should be limited to electricity where the POU is the First Deliverer, as defined in the MRR.

Recommendations

1. No single reporting method is suitable for all utilities; therefore the rule language should allow utilities to report either by source (for POUs within the CAISO) or system (for POUs outside the CAISO), whichever is appropriate.

2. For clarity, "Electricity Sold in to the CAISO Market" should be defined.

3. Throughout the MRR, GHG emissions are reported as an annual aggregate. To be consistent, this new requirement should be revised to report *aggregated annual MWh and GHG emissions* (as the sum of hourly data for electricity sold into the CAISO), rather than by emission factor (which may vary from hour to hour). Reporting by emission factor implies hourly data, which is not appropriate for an annual report.

4. Since there is no compliance obligation on electricity that is re-sold within California, this reporting requirement should be limited to electricity where the reporting entity is the First Deliverer, as defined in the MRR.

Recommended Revisions to the Proposed Rule Language

LADWP recommends the following revisions to the proposed reporting requirement:

95111(a)(12)
"Electrical Distribution Utility Sales into CAISO. ~~All~~ Except for (a) IOUs and (b) POUs that consign all their allocated allowances to auction and attest that no auction proceeds will be used to meet compliance obligations associated with sales into the CAISO markets, electricity distribution utilities ~~except IOUs~~ must report ~~the~~ aggregated annual MWh and GHG emissions, by source or system as specified on the NERC E-tag, of ~~all~~ electricity sold in the CAISO market per the CAISO tariff. where the electricity distribution utility is the First Deliverer ~~and the emission factor for each source~~, beginning with calendar years 2013 and 2014, reported in 2015.

Add definition of Electricity Sold in the CAISO Market
Electricity sold into the CAISO market means any transaction that is financially settled by the CAISO under the CAISO tariff, where the California Independent

System Operator (CAISO) is the contracting counterparty, except for the exclusions specified in Section 11.29 of the CAISO tariff. (LADWP1)

Comment: Reporting ISO Sales Data Staff has proposed adding Section 95111(a)(12), that would impose a new reporting requirement on non-IOU electrical distribution utilities (EDUs), that according to the Initial Statement of Reasons (ISOR), are intended to "quantify the electricity sales that would be subject to the prohibition on uses of allowance value specified in the Cap-and-Trade Regulation." (ISOR, p. 4) The ISOR notes that this is necessary because "to date systematic reporting data had not been collected to monitor and enforce the prohibited use of allowance value in the Cap-and-Trade Regulation." (ISOR, p. 8)
NCPA is concerned that requiring reporting of "sales into the CAISO" without clarifying what such transactions are could cause needless reporting and the collection of unnecessary data. As a starting point for effectively utilizing this proposed amendment, the regulations should include a definition of "Sales into the CAISO." NCPA recommends that the definition for sales into the CAISO recognize the fact that the ISO tariff allows for scheduling of electricity that is not actually a sale, and therefore, not subject to the restrictions in section 95892(d)(5). Accordingly, NCPA recommends that the following definition be added:

> "Electricity Sold in the CAISO Market means any transaction that is financially settled by the CAISO under the CAISO tariff, where the California Independent System Operator (CAISO) is the contracting counterparty, except for the exclusions specified in Section 11.29 of the CAISO tariff."[7]

NCPA also recommends that the proposed amendment be applicable only to EDUs that do not consign all of their freely allocated allowances into the CARB auction, a fact that can be verified in the next year's verification report. The proposed language already acknowledges that the need for this additional reporting stems from the fact that some non-IOU allowances may be placed directly into compliance accounts, since the provision would not apply to IOUs that are required to consign all allowances to auction under the Cap-and-Trade Regulation. Accordingly, NCPA recommends that the provision be amended to reconcile this treatment relevant to the non-IOU EDUs, and that the following language be added to the proposed amendment:
"Electrical Distribution Utility Sales into CAISO.

Electric power entities that are ~~All~~ ~~electricity~~ electrical distribution utilities, except for (a) IOUs and (b) POUs that consign all their allocated allowances for auction, . . ."

Additionally, NCPA notes that determining the emissions factor for any such sales may be difficult if the electricity comes from an EDU's system power. Since many publicly-owned utilities sell electricity from their "system" and not from a specific generator or generation facility, it is necessary to have a methodology for calculating and verifying this emission factor. NCPA has discussed potential scenarios and examples with CARB

[7] This proposed definition for "sales into the CAISO" is consistent with the definition proposed by the Southern California Public Power Authority and the M-S-R Public Power Agency.

staff, but an ultimate solution has not yet been reached. NCPA urges the Board to direct that staff and stakeholders continue these discussions, and that a resolution and clarification of this issue be addressed in 15-day changes.

Finally, in order to ensure that there is no confusion between the various terms and the corresponding reporting requirements, NCPA recommends that the definition for "electrical distribution utilities" found in the Cap-and-Trade Regulation be added to the MRR. That term is used in the proposed amendment, but is not defined in the MRR. The proposed revision set forth above addresses this issue. (NCPA1)

Comment: My name is Susie Berlin. I'm representing the Northern California Power Agency and MSR Public Power. And NCPA and MSR's members are publicly-owned utilities. And today, we are talking obviously about revisions that apply to the electrical utilities. We understand that CARB needs to ensure the integrity of the data reported. However, NCPA and MSR recommend that the proposed amendments for electric power entities be revised in order to remove what we see is ambiguities, ensure accuracy of the data reported, and provide certainty to the compliance entities regarding the materials they'll need to provide.

We have been working with staff and potential revisions to the proposal amendments. And we'd like to express our appreciation for all the time and phone calls that you had with us on this issue. Specifically, with regard to reporting sales into the CALISO, NCPA and MSR recommend the reporting requirements be limited in scope to only those transactions that are necessarily must be verified to ensure the confirmation with the restrictions placed on those use of freely allocated allowances. And we also recommend that CARB adopt the definition for sales into the ISO. Staff has suggested several changes that address some of these concerns. And while Attachment B to draft Resolution anticipates 15-day changes on these matters, it was not listed in staff's presentation for areas where there would be changes. So we want to ensure that there is some acknowledgement that there are ongoing discussions and these revisions will be forthcoming. Of particular concern is the manner in which the information will be reported. And that's something that we have, like I said, been working with staff with. And we appreciate their on-going discussions. (BERLIN1)

> **Response:** Staff has modified section 95111(a)(12) in the proposed amendments to state that the reporting of sales into CAISO is not required for electrical distribution utilities (EDU) that have had all of their directly allocated allowances placed in their limited use holding accounts. Staff has also added language to clarify that EDUs must report sales into CAISO markets for electricity for which the EDU has a compliance obligation. This means that a POU need not report sales for electricity when it is not the first deliverer.
>
> Staff has also modified that section to provide that EDUs must report the source of generation and the source's emission factor, if known, for sales into the CAISO market. Staff believes this meets the commenters' concerns regarding use of a system emission factor. Instead of providing for system emission factors, EDUs

will not be required to report the source and emission factor when a specific source is not known, but will instead report megawatt hours (MWh) and ARB will apply the default emission factor for imported electricity to estimate the emissions associated with those sales. This change also addresses concerns about the differences among POUs and the complexity of estimating GHG emissions in some cases.

As requested by several commenters, staff has added a definition of "electricity sold into the CAISO markets." The definition specifically excludes "self scheduling" transactions that are not CAISO sales pursuant to section 11.29(a)(iii) of the CAISO Fifth Replacement Tariff. Although the proposed definition is not identical to definitions proposed by the commenters, staff believes the definition addresses commenters' concerns regarding which transactions are considered sales into CAISO markets.

Staff notes that the same definition of "electrical distribution utility" that is used in the Cap-and-Trade Regulation has already been added in the proposed regulatory language. Although EDUs may also be electric power entities as defined, it is not necessary to include that term in section 95111(a)(12) because this section pertains only to EDUs.

Staff does not agree that it is sufficient for an EDU to only report aggregated annual MWhs and GHG emissions for sales into CAISO. When the sources and emission factors are known, ARB needs that data to better constrain the quantity of allowances that an EDU will need for CAISO sales.

B-13. Comment: The proposed new data reporting requirements in § 95892(d)(5) for wholesale sales into the California Independent System Operator (CAISO) markets. ARB already has the data necessary for this calculation through CITSS, and hence sees no need for this additional reporting requirement. The additional burden of an unnecessary reporting requirement may be small if it is truly "aggregate", such as reporting only the annual sales into the CAISO market. However, the proposed language goes beyond this aggregate requirement to require reporting of these sales "by source", without including a "system sales" option. SMUD believes that the administrative burden of anything other than annual totals for this purpose makes the requirement onerous, and requests the addition of a "system sales" option to reduce this burden.

II. SMUD Recommends Alternative Language for Proposed New Data Reporting Requirements in § 95892(d)(5) for Wholesale Sales into the California Independent System Operator (CAISO) Markets.

SMUD recommends removing the proposed amendment regarding reporting of sales into the CAISO. SMUD does not see the necessity of adding a provision in the MRR of reporting sales into the CAISO, particularly for electric distribution utilities like SMUD that are not part of the CAISO, but merely sell wholesale power there as available and appropriate. SMUD believes that ARB already has the data necessary to examine these kinds of wholesale sales into the CAISO through the CITSS system. The additional burden of an unnecessary reporting requirement may be small if it is truly "aggregate", such as requiring reporting of only that the overall annual sales into the CAISO market amount.

However, the proposed language goes beyond this aggregate requirement to require reporting of these sales "by source". SMUD's sales into the CAISO are typically from SMUD's "system", known as a "system sale". If the ARB does not remove the provision as SMUD has recommended, SMUD believes that a "system sales" option is required to be able to comply with the proposed requirement in all instances.

SMUD suggests the following edit:

SMUD Proposed Revision:

"Electrical Distribution Utility Sales into CAISO. All electricity distribution utilities except IOUs must report the annual MWh, by source **or by system as specified in the transaction,** of all electricity sold in the CAISO market, and the emission factor for each source **or system as applicable,** beginning with calendar years 2013 and 2014, reported in 2015. (SMUD1)

Response: Staff does not agree that data in the CITSS system are sufficient to determine whether or not an EDU uses freely allocated allowances for sales into CAISO markets. To make this determination, ARB needs data on the quantity of sales into CAISO markets from particular sources, with their specific emission factors, when the sources and emission factors are known by the reporter. However, as discussed in the response to **Comments B-12**, reporters need not report a specific source and emission factor when that data is not known as is typically the case for sales from a system.

General Electric Power Entity Comments

B-14. Comment: ***Lack of transparency regarding guidance and training for entities providing verification services***

Additionally, WPTF remains concerned about the lack of transparency regarding guidance and training for entities providing verification services.

WPTF remains concerned about the lack of transparency regarding verification requirements for electricity importers. As we noted in our formal comments[8] on the record last year, the only verification guidance that was publicly available on CARB's

[8] See WPTF comments on 2013 15 day amendments to MRR at http://www.arb.ca.gov/lists/com-attach/55-ghg2013- WmtTZFd7VjQGNVB9.pdf

website at that time was dated 2011 and corresponds to the 2007 version of the MRR.[9] In light of the significant changes to the regulatory requirements for electric power entities since 2007, we requested that CARB update its guidance and training materials for verifiers and make these materials publicly available on the website. While we suspect that verification training materials have been updated, they are still not publicly available for reporting entities.

Because of the complexity of electricity import transactions and underlying contracts that enable specification of such contracts under the MRR, we believe that the ability of electricity imports to prepare for successful verification would be greatly enhanced by publication of verification training materials. We therefore respectively request for staff to publish and maintain up-to-date verification materials, including technical guidance for specific categories of reporting entities, on its website. (WPTF1)

> **Response:** The comment is outside of the scope of this rulemaking. Regardless, staff will endeavor to provide updated and applicable guidance and FAQs to support accurate reporting under MRR. Staff is always available to answer any questions reporters may have on regulatory requirements.

B-15. Comment: The Independent Energy Producers Association (IEP) submits these comments on the Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (released July 29, 2014). IEP's comments focus on an omission in the scope of these amendments. Specifically, we refer to the need to amend (or at least re-assess) the current and proposed methodology for imputing emissions associated with so-called "Unspecified Imports. "While the CARB is amending certain parts of Section 95111 related to the calculation of GHG emissions from specified facilities or units, IEP is concerned that there are no amendments proposed for Section 95111(b)(l) related to the calculation of the default emissions factor for unspecified electricity imports.

This is not a new or unknown issue. Last year, IEP commissioned a study by Atkins on this matter.[10] We submitted this study for review during the 2013 Mandatory Reporting Amendment Process.[11] Moreover, a number of academics raised concerns about "resource shuffling" and the impact on energy/carbon markets and accurate accounting of emission reductions.[12]

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[9] http://www.arb.ca.gov/cc/reporting/ghg-ver/revised_verification_guidance.pdf

[10] See Atkins, "Greenhouse Gas Emissions Assessment of Imported Power," October 18, 2013.

[11] See Comments of the Independent Energy Producers Association on the Staff Report: Initial Statement of Reasons for Rulemaking Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Filed October 22, 2013, available at: http://www.arb.ca.gov/lists/com-attach/35-ghg2013-B24BY1Yn AAwCZ1 U6.pdf

[12] See James Bushnell, Yihsu Chen, and Matthew Zaragoza-Watkins (2013), Downstream Regulation of C02 Emissions in California's Electricity Sector. Energy Institute at Haas Working Paper #236, avai lable at: http://ei.haas.berkeley.edu/pdf/working_papers/WP236.pdf.; See Danny Cullenward and David Weiskopf(2013), Resource Shuffling and the California Carbon Market. Stanford Law School Environmental and Natural Resources Law & Policy Working Paper; See Comments of Danny

Recently, IEP commissioned Atkins to update its study. Attached for your review and assessment is the new, updated Atkins study: "Greenhouse Gas Emissions of Imported Electricity Updated Assessment," July 2014. Similar to the methodology Atkins employed in 2013, the update study focuses on the Arizona Public Service Company (APS) as a point of comparison due to its close proximity to California for purposes of exporting into California. Notably, APS informed the marketplace on May 13, 2013 that "...any power that is sold from APS has been generated by the APS power system and not specifically by a specific generating resource."[13] As a result, APS exports into California would be imputed an emissions factor based solely on the methodology adopted by the Air Resources Board (ARB) for unspecified imported power.

Importantly, the updated Atkins study concludes the following:

- The emission rates associated with each of the APS portfolio's assumed to supply the power for exempt to California, for both 2010 and 2014, exceed the ARB default emission rate for unspecified electricity imports of0.428 $MTC0_2e/MWh$; often, by a wide margin. For example, the projected 2014 APS portfolio exceeds the default emissions rate by 19% when assessing the emissions from the total APS portfolio; and, it exceeds the default emissions rate by 93% when assessing an APS portfolio that assumes the low-cost, carbon free nuclear and renewable power serves native load.
- A comparison of the APS emission rates between 2009 and 2010 indicates no significant reduction of emissions in the APS system. Moreover, when looking at their integrated resource plans for the future, APS appears committed to a business plan through 2029 that is unlikely to realize significant reductions in carbon emissions from their overall portfolio.
- The competitive advantage realized by APS due to their ability to take advantage of a favorable default emissions factor not available to in-state California generators is significant:
    - The May 2014 carbon allowance auction cleared at $11.34 per allowance. The Atkins study indicates that APS may have avoided $25 to $76 million in carbon costs in 2014, depending on which resources in their portfolio are identified as "unspecified power" imports to California.
    - Assuming carbon allowances were to clear at $15.60 per allowance; APS may avoid $34 million to $105 million in carbon costs in 2014 depending on which types of resources in their portfolio are defined as unspecified power imports to California.
    - Avoidance of this operating cost has a material effect on generators participating in energy markets in California and the west. Currently, the cost of mitigating a ton of carbon emissions (i.e. the allowance cost) is reported to be approximately 6 mills/kWh, which is enough to effect the

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Cullenward on CARE's Proposed Amendments to the California Cap-and-Trade Program (October 2013).

[13] APS Communication re California Cap-and-Trade Resource Shuffling Concerns, dated May 8, 2013.

dispatch order of generation serving load in California and, perhaps, elsewhere.

This round of amendments provides a suitable and needed opportunity to re-consider the current methodology for imputing emissions to unspecified imports. The evidence above demonstrates that the methodology for imputing emissions associated with unspecified imports may be shielding accurate emissions accounting and reporting thereby exacerbating inefficiencies and inequities in the current program design. This may potentially contribute to resource shuffling and GHG emissions "leakage," which undermines the CARE's intent to reduce GHG emissions today and in the near future. Furthermore, to the extent that the allocation of the cost of the Implementation Fee is based on that same accounting mechanism, then the inequities that exist today will continue to persist and undermine the integrity of the AB 32 program generally and the C&T Program specifically.

These amendments present an appropriate opportunity, in advance of the significant expansion of the C&T Program beginning January 1, 2015, to revisit the methodology for imputing emissions associated with unspecified imports. Accordingly, IEP recommends that CARB take this opportunity to revisit and revise the current methodology for imputing emissions to unspecified imported power. In reviewing the current methodology, the goal should be to derive a methodology that accurately reflects the "pool of power" imported into California under the label of Unspecified imports. It would be ideal for the CARB to adopt a new methodology, which would reflect a more accurate default emissions factor, by December 31, 2014, to be applicable to the 2015 compliance period. *[Appendix omitted from this document]* (IEPA1)

> **Response:** This comment is outside of the scope of the proposed amendments. Regardless, staff has addressed similar comments in previous staff reports. The unspecified emissions factor was developed through a public process that also included coordination with CEC and CPUC. For more information please see staff's response to IEP's comments in the MRR 2013 Final Statement of Reasons at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013fsor.pdf

C. Reporting Requirements for Oil and Gas

Reporting Start-up Emissions Associated with Centrifugal Compressors

C-1. Multiple Comments: MRR Section 95103(h) and Section 95153(m)(1)(A) GHG Reporting Requirements for Centrifugal Compressors: Engineering Estimates Are Appropriate for De Minimis Emissions Levels When Cost outweighs Benefit

PG&E supports investment in its system that increases safety, reduces fugitive emissions, and assists in accurate emission reporting. The proposed amendments appear to require PG&E to install meters to measure spin-up gas used to start centrifugal compressors. PG&E believes that the costs of installing meters outweigh the benefits and recommends that the ARB continue to use engineering estimates for centrifugal compressor start-ups, as explained below.

In crafting reporting requirements, ARB should weigh the cost of additional measurement (i.e., the cost of installing meters) against the benefit of greater accuracy (i.e., a better foundation for policy and regulatory design). Currently, engineering estimates are based on the spike in fuel flow rate data during compressor start-up. PG&E believes that this presents an accurate estimate of the non-covered vented emissions because both the amount of gas is known as well as the time period of the start-up. Additionally, engineering estimates are based on conservative assumptions that tend to result in slightly higher emissions than actual measured emissions.

Finally, while installing meters might offer slightly improved accuracy, the benefit would be limited because start-ups represent a small fraction of overall emissions for a facility. For example, PG&E estimates that the total annual vented emissions from compressor spin-up gas at its Burney Compressor Station is 37 metric tons of carbon dioxide equivalent (CO_2e) or less than 0.1 percent of facility total yearly emissions. PG&E estimates installation costs to be approximately $100,000 for each meter, not counting ongoing maintenance expense. Given limited potential improvement in data accuracy, the costs associated with installing new meters appear unjustified.

Accordingly, PG&E proposed the following regulatory language to address this issue:

Amend section 95103(h) as follows:

(h) **Reserved** ~~*Reporting in 20154* All provisions of the regulation are in full effect for 2014 data reporting in 2015 and beyond, except the following: For 2013 data reported in 2014, the following applies:~~
~~(1) Operators in the petroleum and natural gas systems sector subject to section 95103(m)(1)(A) for centrifugal compressor start-ups, may use best available methods to calculate emissions for 2014 data reported in 2015.~~

Amend section 95153(m)(1)(A) as follows:

(A) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors. For all centrifugal compressor start-ups where natural gas is used as spin-up or starting gas (i.e. not combusted in the compressor), venting of this gas must be quantified and reported as follows:

$$ESGi = \sum Vs(1-CF)Yi \qquad \text{(Eq.20)}$$

Where:

ESGi = Annual GHGi (CO_2 and CH_4) vented emissions at standard conditions in cubic feet.

n = number of compressor start-ups using spin gas.

Vsg = Volume of spin-up gas in standard cubic feet ***through metering or estimated using engineering data***.

CF = Fraction of spin-up gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.
Yi=Mole fraction of GHGi in the vent gas.
Calculate both CH4 and CO2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section. (PGE1)

Comment: Section 95153(m). The proposed amendments require the installation of flow meters and reporting of measured start-up emissions for centrifugal compressors if natural gas is used as spin-up or starting gas (i.e. not combusted in the compressor).

Emissions from these sources are negligible (< 3% of total emissions for SoCalGas); therefore, SoCalGas and SDG&E believe that the cost to install flow meters outweighs the benefits. For example, estimates for SoCalGas' Aliso Canyon storage facility indicate that methane emissions from the 3 centrifugal compressors are only about 72 metric tons of CO2e/year. These emissions are in the same order of magnitude as emissions reported in CARB's 2007 Oil & Gas Industry Survey Results report for oil & gas production and natural gas storage facilities (6 MT CH4 as CO2e). The survey says there are only 47 centrifugal compressors out of 1,071 in California. Only 27 out of 47 use natural gas for startup, so this is a very small subset of compressor emissions.

Currently, engineering estimates are used for reporting emissions from centrifugal compressors. The proposed MRR amendments allow engineering estimates for the first year. SoCalGas and SDG&E request that the time limitation be removed because engineering estimates provide sufficient accuracy given the de minimis nature of these emissions.

Accordingly, SoCalGas and SDG&E propose the following regulatory language to address this issue, which is consistent with PG&E's proposed language:

Amend section 95103(h) as follows:
Reserved ~~*Reporting in 201*~~*5*~~*4*~~ ~~All provisions of the regulation are in full effect for 2014 data~~ ~~reporting in 2015 and beyond, except the following:~~ ~~For 2013 data reported in 2014, the following applies:~~
~~Operators in the petroleum and natural gas systems sector subject to section 95103(m)(1)(A) for centrifugal compressor start-ups, may use best available methods to~~ ~~calculate emissions for 2014 data reported in 2015.~~

Amend section 95153(m)(1)(A) as follows:

Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors. For all centrifugal compressor start-ups where natural gas is used as spin-up or starting gas (i.e. not combusted in the compressor), venting of this gas must be quantified and reported as follows:

$ESGi = \sum (1-CF)$ (Eq. 20)

Where:
ESGi = Annual GHGi (CO2 and CH4) vented emissions at standard conditions in cubic feet.
n = number of compressor start-ups using spin gas.
Vsg = Volume of spin-up gas in standard cubic feet ***through metering or estimated using engineering data***.
CF = Fraction of spin-up gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.
Yi = Mole fraction of GHGi in the vent gas.

Calculate both CH4 and CO2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section. (SEMPRA1)

Response: Staff agrees that it is appropriate to allow the use of either metering or engineering estimates when estimating emissions from centrifugal compressor venting start-ups and modified the regulation in 15-day changes to include this option.

Reporting Requirements for Natural Gas Pipeline Dig-ins

C-2. Comment: Section 95102(a)(345)—Scope and Definition of Natural Gas Pipeline Dig-ins: Reporting Should Focus On Distribution System Emissions

To ensure reporting consistency and avoid double-counting, PG&E recommends that ARB clarify that Section 95102(a)(345) applies to distribution pipelines, as described below.

The proposed amendments add Section 95102(a)(345), which defines a “pipeline dig-in” as any “unintentional puncture or rupture to a buried natural gas pipeline during excavation activities.” The applicable source category within the regulation (Section 95150[a][8]) includes emissions from the **natural gas distribution systems** (*emphasis added*) that are operated by a Local Distribution Company (LDC) and specifically excludes emissions from the natural gas transmission system which are addressed in Section 95122. Although Section 95152(i)(11) was added to include reporting GHG emissions from dig-ins under the natural gas distribution source category, PG&E is concerned that if the requirement is extended to transmission system dig-ins, the emissions from the entire natural gas distribution will be overestimated.

PG&E recommends the following amendment in the definition to ensure clarity:
“Pipeline dig-in” means unintentional puncture or rupture to a buried natural gas ***distribution*** pipeline during excavation activities. (PGE1)

Response: Staff agrees that further clarification was needed for the definition of "Pipeline dig-in." Staff modified the definition to clarify that it applies to transmission and distribution pipelines. Staff included both transmission and distribution pipelines in the definition to include all potential pipeline dig-in sources, not just distribution. This is needed because transmission dig-ins could be a significant source of methane emissions.

C-3. Comment: 3. Pipeline Dig-ins

Section 95152(i)(11) and Section 93153(w) require the reporting of CH4 and CO2 emissions from pipeline dig-ins.

(345) "Pipeline dig-in" means unintentional puncture or rupture to a buried natural gas pipeline during excavation activities.
Losses caused by third parties have not been previously incorporated into the MRR as these are emergency events caused by third parties over whom the utilities have no control. Indeed, pipeline dig- ins are usually the result of third party contractors failing to follow industry protocol before excavating. Furthermore, emissions can only be estimated because the release duration may be unknown and response time to control the release varies.

SoCalGas and SDG&E request exclusion from the MRR for emissions associated with pipeline dig-ins.

~~95152(i)(11) CO_2 and CH_4 emissions from pipeline dig-ins (N_2O emissions excluded).~~
~~95152(w) Reserved.Pipeline dig-ins. For reporting pipeline dig-in emissions as specified in section 95152(i)(11), operators may either use measured data or use engineering estimation based on best available data to quantify the volume of natural gas released from pipeline dig-in events. Volumetric emissions must be converted into mass emissions of CO_2 and CH_4 using the applicable methods in paragraphs (r), (s), and (t) of this section.~~

~~95157(c)(16) For local distribution companies, report the following:~~

~~(U) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from customer meters serving residential, commercial, and industrial customers, respectively.~~
~~(V) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from pipeline dig-ins.~~

~~(W) (W) Number of customer meters at residential, commercial, and industrial premises, respectively.~~
~~(X) Number of pipeline dig-ins~~ (SEMPRA1)

> **Response:** Staff declines to make the suggested changes. Sources of fugitive methane emissions are of growing interest, particularly since it is a short-lived climate pollutant and greater reductions could have a near-term impact on climate effects. Because of the potential magnitude of the sources, information will support a complete and more accurate estimate of natural gas transmission and distribution emissions in the statewide inventory and inform regulatory development. Emissions associated with natural gas dig-ins must already be accounted for under other regulatory programs and therefore the proposed amendment does not require additional monitoring or testing. The commenter states that the dig-in emissions can only be estimated. We agree with this comment, and the regulation allows use of estimation methods. Specifically, section 95113(w) specifies that "…operators may use either measured data or use engineering estimation based on best available data to quantify the volume of natural gas released from pipeline dig-in events." Therefore, no change to the regulation is needed.

Reporting Requirements for Pipeline Blowdowns

C-4. Comment: Section 95152(i)(9)—Reporting Natural Gas Distribution Emissions: Clarify What "Equipment Leaks" are to be Reported

This provision requires emissions to be reported for "Equipment leaks <u>and pipeline blowdowns</u>." Sections 95152(i)(1) – (5) address the various equipment leaks that can be found in the distribution system, such as above-grade transmission and distribution (T-D) stations, above and below ground metering and regulating (M&R) stations, and distribution main equipment leaks.

PG&E seeks clarification on what additional equipment leaks need to be reported in 95152(i)(9). (PGE1)

> **Response:** Thank you for your comment. Staff clarified the requirement by removing the word "leaks" from 95153(i)(9) so it is explicit that the requirement is specific only to blowdowns, and not all equipment leaks.

D. Reporting Requirements for Legacy Contract Generators

D-1. Comment: Wheelabrator's Norwalk Energy power plant is a legacy contract holder that is a combined cycle generation facility producing energy through three different processes. Natural gas powers a 27-megawatt LM2500 gas turbine to produce electricity that is sold to Southern California Edison in accordance with a Power Purchase Agreement executed in 1988. The facility's turbine's exhaust gasses are directed to a heat recovery steam generator (HRSG), where it heats water. The steam from that process turns a second turbine, which also produces electricity. Steam from the HRSG, or the auxiliary boilers when the turbine is not operating, is also provided flows through a pipeline to the neighboring state hospital campus where it is used for heating. In addition to electricity and steam, Wheelabrator's Norwalk Energy facility also provides chilled water to the state hospital for space cooling, using three 1,500-ton chillers. Two of the chillers are electrical and the third is an absorption chiller which uses steam from the HRSG.

Wheelabrator's Norwalk Energy facility provides electrical power to Southern California Edison under a 30-year Power Purchase Agreement (PPA) executed on February 14, 1988. The PPA does not provide an explicit means of cost recovery for the facility's compliance with the California C&T Program and meets the definition of a legacy contract. Similarly, the Norwalk Energy facility contract with its thermal customer meets the definition of a legacy contract.

With regard to the proposed Amendments, we wish to point out that the process flow diagram for the Norwalk Energy facility is not necessarily a simple document, given Norwalk's combined cycle technology that provides maximum system efficiency while minimizing fuel consumption and environmental impacts.

However, we understand the ARB's need for the information as described in the Amendments and generally support the proposed revisions to Section 95112, but ask for clarification on questions related to the following Sections:

1. In 95112(i)(1)(A), the plant's auxiliary boilers are not part of the cogeneration system but information from operation of these boilers is needed to demonstrate the appropriate level of legacy contract allocations. To this end, the first sentence might be clearer if it read (added language in bold), "...regardless of whether the facility operator, **or the equipment**, is itself otherwise subject to..."
2. In 95112(i)(1)(B), the phrase "by either the facility operator" seems to be incomplete. Should the word "either" be removed? Conversely, the phrase should be corrected to provide reference to the word "either".
3. In 95112(i)(1)(B), "the resulting greenhouse gas emissions as reported elsewhere under this regulation" are to be included on the diagram. Does the regulation require delineation in the diagram of individual greenhouse gas compounds including CO2, CH4, and N20, or would emissions expressed in CO2e be sufficient? Guidance or corrected language should be added to address whether individual compounds, carbon equivalents, or both must be included on the diagram. (WNEC1)

Response: Staff agrees and has modified section 95112(i)(1)(A) to include the words “or the equipment” as recommended by the commenter. In section 95112(i)(1)(B), staff has clarified that the diagram must be labeled to show resulting emissions in CO_2e and not separately by individual greenhouse gases, and staff has removed the word “either” as recommended by the commenter.

D-2. Comment: _Summary_

The Proposed MRR Amendments would require applicants for legacy contract assistance to include detailed information in block-diagram format concerning the flow of thermal energy products, the location of meters, the type and amounts of thermal energy products delivered, the amount of fuel consumed and the resulting greenhouse gas ("GHG") emissions. Calpine appreciates CARB's amendment of the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (Cal. Code Reg. tit. 17, §§ 95800 et seq., "Cap-and-Trade Regulation") to provide legacy contract assistance to legacy contract generators. Calpine believes that CARB already has the authority under those amendments to request just the type of information that would be required from legacy contract generators under the Proposed MRR Amendments, whenever the information submitted on the application for legacy contract assistance is not self-evident and the Executive Officer needs additional clarification to determine whether an allocation should be provided and the amount of such allocation. Calpine believes that CARB should not make the legacy contract generator's obligation to provide such information an express requirement of the MRR because the information that would need to be included on the block diagram is highly detailed and complex and, consequently, the risk that an immaterial mistake could result, which could lead to potentially large penalties for violations of the MRR, is high. Accordingly, Calpine recommends that CARB withdraw the Proposed Amendments to section 95112(i)(1) of the MRR and instead obtain the pertinent information whenever it is needed to determine a legacy contract allocation pursuant to its existing authority under the Cap-and-Trade Regulation.

Background

The Mandatory Reporting Rule currently requires facility operators that are applying for legacy contract transition assistance under the Cap-and-Trade Regulation to submit, among other things, "a simplified block diagram depicting the following, as applicable: individual equipment included in the generation system (e.g. turbine, engine, boiler, heat recovery steam generator); direction of flows of energy specified in paragraphs (a)(4)-(5), (b)(2)-(4) and (b)(7)-(8) of this section, with the forms of energy carrier (e.g. steam, water, fuel) labeled; and relative locations of fuel meters and other fuel quantity measurements" for the first year of reporting only. MRR § 95112(a)(6). However, "[i]f the cogeneration or bigeneration system is modified after the initial submission of the diagram, the operator must resubmit an updated diagram to [CARB]." Id.

Proposed Amendments to MRR

The Proposed MRR Amendments would amend the above requirement such that the block diagram must be submitted every year, not just the first year of reporting. Proposed MRR Amendments § 95112(i). Additionally, "[t]he diagram must depict the following elements:

(A) For the data year, all of the information described in sections 95112(a)(4)-(5), as applicable, regardless of whether the facility operator is itself otherwise subject to sections 95112(a)(4)-(5). This information reflects electricity and thermal energy flows, including information identifying the recipient(s) of the electricity and/or thermal energy. Also report the quantities of any other products provided or sold under the legacy contract, using the units in which they are reported elsewhere in this regulation, if applicable. The diagram must indicate where each of these energy flows or products is measured. In addition, the following information must be included:

1. Each of the amounts reported under section 95112(i)(1)(A) must be labeled indicating whether or not it was provided under the legacy contract; and

2. All thermal energy products must be labeled with the type of thermal energy product (e.g., steam, hot water, chilled water, distilled water).

(B) The individual equipment included in the system for which the facility operator is applying for legacy contract transition assistance, and other equipment that is not an integral part of that system but produces or consumes energy that is sent to or received from that system and is owned or operated by either the facility operator[14]. Boilers, individual generators such as heat recovery steam generators, turbines if separate from generators, ice plants, chillers, purifiers and other equipment that meet these criteria must each be shown separately in the diagram. In addition, label each piece of equipment with the amount of fuel consumed (in MMBtu) by that piece of equipment during the data year, if any, and the resulting greenhouse gas emissions as reported elsewhere under this regulation. The diagram must also indicate the fuel meter where this fuel use was measured, and the amount measured.

(C) An outline showing the boundary of the activities covered by the legacy contract.

Id. § 95112(i)(1).

<u>*Calpine's Concern with the Proposed Amendments*</u>

The proposed notation requirements described above would significantly increase the complexity of the block diagram submission. For instance, each piece of equipment must be labeled with the amount of fuel consumed (in MMBtu) by that piece of equipment during the data year, if any, and the resulting GHG emissions as reported elsewhere under the MRR, *even if* the equipment is not an integral part of the system for which the facility operator is applying for legacy contract transition assistance (but produces or consumes energy that is sent to or received from that system). *Id.* §

[14] We note that the phrase "by either the facility" appears to be mistakenly truncated; presumably CARB intended to include the phrase "or any other party" afterwards.

95112(i)(1)(B). Moreover, the information required regarding all deliveries of thermal energy products would essentially transform the simple block diagram currently required into a highly detailed heat balance. Calpine does not believe the emissions data report and corresponding block diagram requirement are conducive to such a highly detailed exercise regarding documentation of all thermal energy flows (e.g., enthalpy in returned condensate). Reducing all this complex information into block-diagram format presents a cognizable risk of error, due to no lack of diligence on the part of the covered entity, but solely to the fact that the required notations and associated calculations can be incredibly complex.

If a covered entity applying for legacy contract transition assistance were to accidently make even a minor error in the notation on the block diagram, which is submitted as part of the annual emissions data report, this could serve as grounds for CARB to take enforcement action against the covered entity, including the imposition of significant penalties. Under the MRR, "[e]ach day or portion thereof that any report required by this article remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate is a single, separate violation."[15] The risk that the information submitted in block-diagram format could be deemed "incomplete" or "inaccurate" is high. This represents an unwarranted risk to impose upon legacy contract generators, especially because CARB can request pertinent additional information from any legacy contract applicant via the Cap-and-Trade Regulation. *See* Cap-and-Trade Regulation § 95894(e).[16] This authority under the Cap-and-Trade Regulation permits CARB to request the *exact type* of information reflected in Section 95112(i)(1) of the Proposed MRR Amendments, but does not carry the same degree of risk as would inclusion in the facility's emissions data report.[17]

Furthermore, CARB may not even need all the detailed information required by the Proposed MRR Amendments to establish the appropriate legacy contract allocation in all circumstances. While Calpine appreciates the opportunity to obtain legacy contract assistance for several of its cogeneration facilities, CARB does not need to understand the entire heat balance for such facilities in order to calculate the appropriate legacy contract allocation pursuant to Section 95894. Given the highly complex and sensitive nature of information that would be required pursuant to the

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[15] MRR § 95107(b). The information required in block-diagram format would constitute a "report" ("report" includes "any emissions data report, verification statement, or other document required to be submitted to the Executive Officer by this article"). See id.

[16] In determining the appropriate values for section 95894(c) and 95894(d), the Executive Officer may employ all available data reported to ARB under MRR and all other relevant data, including invoices, that demonstrate the amount of electricity and legacy contract qualified thermal output sold or provided for off-site use does not include a carbon cost in the budget year for which it is seeking an allocation. If necessary, the Executive Officer will solicit additional data to establish a representative allocation. The operator of the legacy contract generator with an industrial counterparty and the operator of a legacy contract generator without an industrial counterparty, must provide the additional data upon request by the Executive Officer." Cap-and-Trade Regulation §95894(e) (emphasis added).

[17] See Cap-and-Trade Regulation § 96014(c)(4)-(5) (making it a violation, inter alia, if someone "[o]mits material facts from a submittal or record" and defining "material" as a fact that "could probably influence a decision by the Executive Officer, the Board, or the Board's staff."). Compare MRR § 95107(b) (making each day that any report remains unsubmitted, incomplete or inaccurate a separate violation).

Proposed Amendments and the risk of potential enforcement if any such information should inadvertently prove inaccurate or incomplete in some immaterial respect, Calpine urges CARB to use its existing authority to request any additional information necessary to establish a legacy contract allocation and not finalize proposed Section 95112(i). (CALPINE1)

> **Response:** Staff is requiring this information because it is necessary to understand legacy contracts. Most of the information is already required for all cogeneration facilities, and staff is adding a few additional details to understand which portions of an entity's operations are impacted by the legacy contract.
>
> The diagram need not be a professionally drawn computer-assisted-design document. Many reporting entities draw their diagrams by hand and that is acceptable to both verifiers and ARB staff.
>
> Moreover, although cogeneration operators have an incredible wealth of data and information about their systems, the proposed amendments are only asking for the bigger picture of energy flows and related emissions going into and out from the cogeneration system components. Staff believes this is a reasonable level of detail. Without this information there could be a delay in processing the exemptions or allocations before the Cap-and-Trade Program deadlines.
>
> Because the data contained in the block diagram may be used as part of the determination of free allocation of allowances for legacy contracts, ARB must have the ability to take enforcement action, if necessary. As with other reported information, if there are reporting errors in the block diagram, reporting entities may make any necessary changes during the verification process before the final report is submitted.

E. Product Data Reporting Requirements

Refinery Product Data Reporting Requirements

E-1. Multiple Comments: <u>Additional Reporting Requirements – Primary Refinery Products</u>

Any new data collection and reporting provisions that are not directly related either to allocation of emission allowances or to assessment of fees necessary to cover the cost of implementing AB 32 programs should be eliminated from the regulation. ARB should reconsider the need amend to primary refinery product reporting requirements. The practical effect of the proposed regulation is it will distract entities from the ongoing task of compliance and create an additional reporting burden that should not be done through the MRR regulation.

Incorporating the proposed reporting provisions would create an annual reporting obligation, which may not be necessary to achieve the objectives sought by ARB. More importantly, it would create uncertainty as to whether the data is subject to existing regulatory requirements for measurement accuracy, material misstatement, third party verification, etc. This uncertainty exists despite the fact that it would have no bearing on allowance allocations to the regulated entity.

Recommendation: Remove the Primary Refinery Products Reporting Provisions from the MRR regulation because they are not related to allowances or fees. Any additional data sought by ARB should be clearly justified, the intended use of the data disclosed and the data should be gathered by non-regulatory means, such as a one-time survey. At a minimum, if ARB believes it must require submittal of the data through the regulation, it should be subject to a reasonable sunset provision such as 2 years. (WSPA1)

Comment: Finally, I'd refer to the Board our letter on this issue. On page three and four, we made a specific request relative to reporting primary refinery products. Want to make clear right now companies are obligated to report under CWB. The new regulation proposed would add a new addition to primary refinery product. And as you heard the staff say in response to a Board Resolution trying to explore the difference between CWB and the single barrel. What we would like to do is pull that requirement out of the regulation. We would be happy to submit it as part of the survey. But putting that data request in a regulation puts companies in between. It's something that's not needed. Thank you. (WSPA2)

Response: The revisions to primary refinery product data reporting align MRR requirements with the intent of allowance allocation in the Cap-and-Trade Regulation, which is that free allowances are provided to sectors with product-based benchmarks based on actual on-site production.

Some 2014 primary refinery product data will impact allowance allocation. Reported primary product data for the 2014 data year will be used to calculate the true-up portion of free allowance allocations for the subset of refineries that do not report a Solomon EII value and that did not receive a vintage 2013 or vintage 2014 emissions-based allowance allocation.

All reported data are subject to accuracy requirements. For refineries that do not report a Solomon EII value, reported 2014 primary product data are covered product data, and therefore, subject to material misstatement requirements, but material misstatement requirements for primary refinery product data have been removed for the 2015 data year and beyond. For refineries that do report a Solomon EII value, material misstatement requirements for primary product data have been removed for the 2014 data year and beyond. There is no uncertainty in MRR regarding accuracy requirements or material misstatement requirements for reported primary refinery product data.

The Board has directed ARB staff to compare refinery allowance allocations under the complexity weighted barrel-based allocation methodology and a primary product-based allocation methodology. To satisfy this request, primary product data are needed so that staff can evaluate hypothetical allocation outcomes for the two approaches over several reporting years. Staff believes that the underlying complexity-weighted barrel (CWB) and primary product data for this evaluation must be directly comparable—i.e., they should reflect actual on-site production that contributed to facility covered emissions. Currently, there is no year for which staff have CWB and primary product data that are verified and directly comparable. Staff believes that the revised primary refinery product data reporting requirements are the best means to acquiring the needed data to satisfy the Board request.

Subjecting primary product data reporting to a sunset provision after which it is no longer required is a possible approach, but staff believes that only two years of data would be insufficient to meet the Board's request. Staff will continue to work with stakeholders to determine the appropriate time frame for including these reporting requirements.

E-2. Comment: Revisions to Reporting of Primary Refinery Products, 95113(l)

Kern is not supportive of changes to the reporting requirements for primary refinery products in Section 95113(l). Proposed revisions to this section are purportedly to clarify the primary refinery product data that has been reported, and is subsequently used in the primary-refinery product based benchmarks and allocations process. Kern understands ARB's intention to distinguish between those products produced on-site versus those produced elsewhere and brought on-site for blending or other use. However, Kern would like to point out that this change in data reporting, which will impact allowance allocation true-up for reporting year 2014, is intended for implementation mid-triennial compliance period for the Cap and Trade Program. Such a change in methodology mid-compliance period is unfair to entities that have made certain Cap and Trade compliance strategies using estimates and projections based on the existing MRR data reporting requirements. This change to product data reporting will result in a negative true up for non-Eii refineries that received allocations based on product data.

Additionally, this proposed change in reporting is intended to take effect in 2015 for operating year 2014. However, the proposed change was only introduced as a concept with the release of this 45-day rulemaking notice – some 7 months into the 2014 operating year. Entities would be expected to comply with the +/- 5% accuracy requirements for avoiding material misstatements even though opportunities for accurate data collection and management will have already transpired by the time the changes are effective. For example, the most effective way to collect the on-site production data for primary refinery products and blendstocks separately from those quantities purchased and brought on-site may be through installation of new product meters. However, the effective date of the proposed change allows no opportunity for operators to assess and implement such a plan. (KERN1)

Response: Staff believes that clarifying primary refinery product reporting requirements minimizes potential inequities in free allowance allocation among refineries owing to reporting inconsistencies. The requirement that reported primary refinery product data include only on-site production that contributes to covered emissions, and exclude material produced elsewhere and then brought on-site, is not a change in data reporting but a clarification to the historic reporting requirements. The revised regulation requests additional information about material produced elsewhere and then brought on-site so that ARB can confirm that primary product reporting is consistent with the intent of the previous regulation. It does not change the reported primary product data upon which allocation is based, which is on-site production that contributes to covered emissions, so these revisions should not impact Cap-and-Trade Program compliance strategies.

Staff notes that true-up allocations are only a correction to the amount of free allowances that an entity should have initially received. ARB initially allocates free allowances in advance of reporting years based on estimates from historical data. After verified data for the reporting year are received, ARB corrects the initial allocation estimate to the actual allocation using the true-up allocation. If a true-up allocation for an entity is negative, it is because that entity previously received too many free allowances. A negative true-up is not a penalty and a positive true-up is not a reward; a true-up allocation is only a correction to the appropriate allocation based on verified data.

Staff acknowledges that the requirement to report the quantity of primary refinery product and blending component produced elsewhere and brought on-site for the 2014 data year to ARB was introduced during that 2014 data year. These reporting requirements clarify guidance released by ARB in May 2014 and may be satisfied by using best available methods for the 2014 data year.

Hydrogen Product Data Reporting Requirements

E-3. Comment: § 95103 (h)(4): WSPA does not agree with the elimination of best available methods for measuring by-product hydrogen. The by-product hydrogen is not currently incorporated into the CWB calculation and resultant allocations so it should not be subject to the more stringent accuracy requirements. (WSPA1)

Response: Section 95103(h) of the regulation is used to identify new reporting requirements that may take additional time for reporters to fully implement due to the need for additional data collection or monitoring, and allow reporters to use best available methods for reporting the new data in the first year of reporting. Reporting requirements for by-product hydrogen became effective on January 1, 2014, and best available methods were allowed for 2013 data reported in 2014. Because reporting by product hydrogen is not a new requirement for 2014 data, best available methods is not needed for data reported in 2015.

Paper Product Data Reporting Requirements

E-4. Comment: I can't borrow time from anybody. Very quickly, I'm Nico Van Aelstyn. I speak today now on behalf of Kimberly-Clark Corporation. Thank you for this opportunity to speak directly with you on a matter that stands to dramatically affect the competitiveness of KC's Fullerton facility. You may recall hearing from Dell Majure, KC's global technical leader on air issues, at April's last Board meeting. My comments today address the proposed amendments to the required emission reporting regulations now before the Board, but they are continuation of KC's comments in April. Before turning to those comments, please allow me to again make very clear that KC supports AB 32 and its objectives.

As a company, Kimberly-Clark has invested heavily in California and globally to improve energy efficiency and reduce carbon intensity and has already exceeded its 2015 enterprise-wise GHG reduction target and is on track to almost double, while growing the business.

However, while KC supports the objectives of AB 32, we have very serious objections to the emission benchmark for the tissue industry sector in the cap and trade regulation. These concerns compel us to object to the proposed modifications to the mandatory reporting rules, 24 specifically Sections 95102(b)(10), (37), (45), (75), and (101), which are the new definitions of bathroom, facial, delicate task, paper towel, and tissue produced, adjusted by absorbency capacity, the key issue. And also Section 95119(d) which regulates reporting of production data by the tissue manufacturers.

These changes appear to be intended to bring the MRR in line with the new benchmarks for the tissue sector that were adopted in April. As KC noted in its comments during that rulemaking process, that new tissue benchmark is fundamentally flawed. It measures the functionality of bathroom tissue solely by its water absorbent capacity, even though ARB has no scientific basis to do so.

Further, the new tissue benchmark segregates all tissue products into sub-categories -- the four I mentioned -- and assigned the discrete benchmark to each, despite the fact that ARB had no data on which to base those benchmarks. The proposed changes to the MRR would incorporate these same errors into the parts of the MRR that apply to the tissue manufacturing sector. As noted, ARB has no scientific basis for adjusting the tissue benchmark to reflect the water absorbency of bath tissue, a change that dramatic favors technology used by one market participant in the tissue sector at the expense of the other. And ARB still has no scientific basis for now introducing the concept of water absorbency into the MRR.

In addition, the fact that ARB is now five months later proposing to gather data about discrete sub-categories just demonstrates that it did not have the necessary data when it modified the tissue benchmark in April. These proposed modifications to the MRR would perpetuate the deeply flawed tissue benchmark and further entrench an unfair and scientifically untenable regulation. KC therefore asks the Board not to move on the specific changes and to consider directing staff to address the tissue benchmark in the cap and trade regulation. (KC1)

> **Response:** The proposed amendments regarding the definitions of tissue products and product data reporting requirements are aimed to support California's Cap-and-Trade Regulation by making conforming changes. The amendment to the Cap-and-Trade Regulation that included new tissue sector benchmarks was approved by the Board in April 2014, and went into effect in July 2014. That decision is beyond the scope of this rulemaking.

F. Fuel Supplier Reporting Requirements

F-1. Multiple Comments: On behalf of Waste Management (WM), I am submitting comments on the Proposed Amendments (Amendments) to the Regulations For The Mandatory Reporting of Greenhouse Gas Emissions (MRR) CARB issued July 29, 2014 for public comment. We appreciate the opportunity to submit these comments on the Amendments. The proposed changes can have a significant impact on development of the beneficial use of biomethane -- one of California's cleanest transportation fuels – if the Amendments, as proposed, subject biomethane producers who do not deliver to the bulk/terminal system to substantial reporting requirements.

WM is the leading provider of comprehensive waste management and environmental services in North America. The company serves approximately 20 million municipal, commercial, industrial and residential customers through a network of 390 collection operations, 294 transfer stations, 266 active municipal solid waste (MSW) landfill disposal sites, 121 recycling facilities, 34 organic processing facilities and 131 beneficial-use landfill gas projects. Many of these facilities operate in California.

Newly proposed Sections 95101 and 95121 revise MRR applicability for fuel suppliers from those who import petroleum to any and all suppliers of transportation fuels – including those producing biomass-derived fuels -- and require reporting of emissions greater than 10,000 tons CO2e annually by those suppliers that "produce or deliver transportation fuel outside the bulk/terminal system."

Emissions from biofuel facilities are calculated in accordance with Section 95212, Table 1, page 33, that lists biodiesel and renewable diesel. Renewable diesel has an equivalent emission factor of Distillate No. 2, as amended by the proposal. Biodiesel has a CH_4 emission factor of 2 g/bbl and N_2O factor of 1 g/bbl. Biodiesel and renewable diesel are listed on Table 1, but there is no specific listing for biomethane.

Despite the lack of listing biomethane in Table 1, we are concerned that the proposed changes to the MRR could subject biomethane suppliers who deliver outside the bulk/transfer system – such as delivery for internal company use – to costly and burdensome reporting.

For example, WM's Altamont LNG plant is the most successful commercial scale facility of its kind that generates transportation fuel from landfill gas biomethane. Built in 2009, the facility is a joint venture between Waste Management and Linde North America. The plant is designed to produce 13,000 gallons of clean-burning natural gas daily – enough to power nearly 300 WM collection vehicles in California every day. Although commercial in scale, it provides fuel only for use within Waste Management Fleet of California natural gas heavy-duty vehicles.

Use of this near-zero carbon fuel eliminates nearly 30,000 tons of carbon dioxide emissions annually. According to the ARB, it is the lowest carbon intensity fuel available today. Converting landfill gas to a green alternative to fossil fuel is the ultimate closed-loop approach to managing historic waste streams while significantly lowering greenhouse gas emissions from the transportation sector.

WM plans to expand its production of transportation fuels from landfill gas for use in its collection fleets, including use of biomethane produced from its own landfills and biogas delivered from other landfill sources outside California.

The proposed Amendments appear to subject Altamont, and any other project like it, to registration, reporting and verification of emissions from its clean fuel. The Amendments add to the costs and, in doing so, will hinder development of a clean fuel that already faces severe obstacles to development.

As the ARB is aware, the California Public Utility Commission (CPUC) completed its first phase of a rulemaking to set standards for pipeline injection of biomethane, including requirements for testing, monitoring and controlling 17 constituents of concern, as well as a 990 BTU heating content requirement that, taken together, are virtually cost-prohibitive if paid solely by the biomethane generator. While the CPUC currently is determining allocation of development, interconnect and other costs ofbiomethane development, it is important to point out that the standards could result in very little production of biomethane within California for use in California.

Biomethane faces additional hurdles with regard to agency support for its use, despite clear support from the legislature in its passage of AB 1900. For example, a recent solicitation by the Electric Program Investment Charge (EPIC) specifically excludes pipeline biomethane in its $27 million "Demonstrating Bioenergy Solutions the Support California Industries, the Environment and the Grid (PON 14-305)" and points instead to the Public Interest Energy Research (PIER) program for funding despite no announced intension by PIER or AB 118 to offer support. In fact, our inquiries with regard to PIER or AB 118 funding have met with silence and there is no discussion of biomethane on PIER or AB 118 websites.

For these reasons, we urge ARB to make clear an exclusion from reporting requirements all biomethane-based transportation fuels generated by non-fossil fuel suppliers not otherwise subjected to the Cap and Trade rules and delivered for use by entities not otherwise subject to the rule or for internal consumption by such entities.

In particular, we ask that the ARB adopt the following changes to the amended MRR (see **bolded text)**:

In subsection (c) of Section 95101 titled “Fuel and Carbon Dioxide Suppliers”:

(c) The suppliers listed below, as defined in section 95102(a), are required to report under this article when they produce, import and/or deliver an annual quantity of fuel that, if completely combusted, oxidized, or used in other processes, would result in the release of greater than or equal to 10,000 metric tons of CO_2e in California, unless otherwise specified in this article:

Position holders at terminals and refiners delivering petroleum fuels and/or biomass-derived fuels, as described in section 95121;

Enterers that import transportation ~~petroleum~~ fuels outside the bulk transfer/terminal system, as described in section 95121, and biofuel production facilities that produce and deliver transportation fuels outside the bulk/terminal system, as described in section 95121;

***(3) Nothing in this Section 95101 shall be interpreted to include generators or suppliers of biomethane in the definition of biofuel production facilities, supplier or importer of transportation fuels for purposes of reporting**.*

Further, we recommend the following amended language to Section 95121(a)(2) (see **bolded text**).

*(2) Refiners, position holders of fossil fuels and biomass-derived fuels that supply fuel at California terminal racks, and enterers that import transportation fuels outside the bulk transfer/terminal system, and biofuel production facilities that produce and deliver biomass-derived fuels outside the bulk transfer/ terminal system in California ~~of fossil fuels~~ must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2 of this section. However, reporting is not required for fuel in which a final destination outside California, **biomethane**, or where a use in exclusively aviation or marine applications can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2 of this section. For purposes of this article, CARBOB blendstocks are reported as RBOB blendstocks.* (WM1)

Comment: The expansion of Section 95101 (c) “Applicability” to include suppliers that import transportation fuels, as described in section 95121, appears to be overly broad and should be further amended to clarify biomethane’s exclusion from registration and reporting requirements.

The Coalition for Renewable Natural Gas requests clarifying language to ensure that biomethane suppliers are not required to register and report under the MRR.

Appendix A to the Staff Report delineates the Proposed Amendments to the MRR. In subsection (c) of Section 95101 titled “Fuel and Carbon Dioxide Suppliers” it says:

> *(c) **The suppliers listed below**, as defined in section 95102(a), **are required to report** under this article when they produce, import and/or deliver an annual quantity of fuel that, if completely combusted, oxidized, or used in other processes, would result in the release of greater than or equal to 10,000 metric tons of CO e in California, unless otherwise specified in this article:*
>
> *(1) Position holders at terminals and refiners delivering petroleum fuels and/or biomass-derived fuels, as described in section 95121;*
>
> *(2) **Enterers that import transportation** ~~petroleum~~ **fuels** outside the bulk transfer/terminal system, **as described in section 95121, and biofuel production facilities** that produce and deliver transportation fuels outside the bulk/terminal system, **as described in section 95121**; (Emphasis Added).*

Inclusion of “biofuel production facilities” that produce and deliver transportation fuels outside the bulk/terminal system appears to mean that suppliers of bio- based transportation fuels are now included in MRR requirement. The limitation on this interpretation is the phrase “as described in section 95121.” However, as we will discuss below, this section may also be subject to broad interpretations that may include biomethane.

Section 95102(a) (447) defines a “Supplier” as:

> *“A producer, importer, exporter, position holder, interstate pipeline operator, or local distribution of **fossil fuel** or an industrial greenhouse gas.” (Emphasis Added).*

The limitation in this definition to “fossil fuel or industrial greenhouse gas” appears to be expanded by inclusion of the Section 95101(c)(2) bolded languageabove that includes importers of “transportation” fuels rather than “petroleum” fuels.

This newly amended inclusion of “biofuel production facilities” is also reflected in Section 95121.

The proposed amendments to Section 95121, entitled “Suppliers of Transportation Fuels,” would read:

*"**Any** position holder, refiner, enterer, or ~~refiner~~ **biofuel production facility** **who is required to report under section 95101 of this article must comply**… in reporting emission and related data to ARB, except as otherwise provided in this section." (Emphasis Added).*

ARB staff kindly met with staff and members of the Coalition for Renewable Natural Gas regarding our concerns with an interpretation of this language that would include biomethane in the MRR. ARB staff has assured us that inclusion of biomethane is not intended, and pointed to Table 2, entitled "Blendstocks, Distillate Fuel Oils and Biomass-Derived Fuels Subject to Reporting under section 95121" as evidence. Table 2 lists Biomass-Derived Fuels and does not list biomethane. This has assured us of ARB's intentions. Nevertheless, while we do read several subsection of Section 95121 referencing *"biomass-derived fuels listed in Table 2"* these references are generally found in specific reporting requirement sections.

The best example of a broad intent to limit MRR applicability is in Section 95121(a)(2):

> (2) **Refiners, position holders of fossil fuels** and **biomass-derived fuels** that supply fuel at California terminal racks, ~~and~~ **enterers that import transportation fuels outside the bulk transfer/terminal system, and biofuel production facilities that produce and deliver biomass-derived fuels outside the bulk transfer/ terminal system in California** ~~of fossil fuels~~ **must report** the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e **emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2 of this section.** However, reporting is not required for fuel in which a final destination outside California or where a use in exclusively aviation or marine applications can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2 of this section. For purposes of this article, CARBOB blendstocks are reported as RBOB blendstocks. *(Emphasis Added).*

Reading this section leads us to an interpretation that resulting emissions from combustion or oxidation of biomass based fuels listed in Table 2 are included in the MRR. It does not lead us to the conclusion that only those fuels listed in Table 2 have reporting requirements under the MRR. Language found in other sections suggest the contrary.

For example, Section 95121(d)(7) says:

> "**All fuel suppliers identified in this section must report the total quantity of** CARBOB, California Gasoline, California diesel fuel, and **biomass-derived fuel** that was imported from outside California for use in California…." *(Emphasis Added).*

Also, a plain reading of the MRR definition section does not exclude biomethane as a biomass-derived fuel. Section 95102(a) (38) defines “Biomass-derived fuels” or “biomass fuels” or “biofuels” or “biomass-based fuels” as *“fuels derived from biomass.”* Broadly speaking, and consistent with the other definitions in this section, biomethane is derived from biogas which is a byproduct of biomass. Accordingly, to differentiate biomass-derived fuels that are included in the MRR requirements from those that are not included, we believe further clarifying language is needed.

Respectfully, we request a statement of preclusion, such as “Biomass- derived fuels not listed in Table 2 are not subject to the registration and reporting requirements of this article,” to add increased clarity.

Inclusion of registration and reporting requirements for biomethane in the MRR would place a significant burden on biomethane suppliers. Additionally, the information captured by such a requirement would not add value to the ARB’s current MRR objectives. We trust it was not your intention that the proposed amendments would capture biomethane-based transportation fuels in the MRR. (CFRNG1)

Comment: My name is David Cox. I'm here on behalf of the Coalition for Renewable Natural Gas. We are a trade association representing the biomethane industry. I want to thank you for the opportunity to speak to you here today. And we have submitted written comments on this point. And let me just say that I've heard it said that if you can get ten lawyers in a room, you're a guaranteed to get 15 different interpretations of a document. I represent 50 companies. They all have lawyers. There's nothing they like to debate more than clarifying amendments and what is actually being clarified here. So thank Mr. Gaffney for his presentation today. I heard and I think I heard you loud and clear that there are no new requirements in these amendments. But maybe just to get affirmation from the Board to get it on the record and help my members sleep better at night, I'll ask my question anyway. We're seeking clarification from the Board if and whether the biomass derived fuels that are to be reported pursuant to Section 95121 are the only fuels that are in that Section's Table 2. And similarly, if those suppliers of biomass-based transportation fuels that are subject to that reporting requirement are only those suppliers who are deriving those fuels listed in table two. My members are concerned that the way that we're switching the word petroleum fuels to transportation fuels and including that biomass-based fuels phrase in there that we may come up with a situation later in the compliance phases where biomethane is incorporated in there. I just appreciate the Board or staff's clarification on that point. And thank you so much. (CFRNG2)

> **Response:** Staff appreciates the comment and explanation provided by the commenters; however, staff declines to make the requested change as the current language is sufficient given that biomethane is not listed as a reportable transportation fuel in Table 2 of section 95121. Section 95121(a)(2) clearly states that transportation fuel suppliers must report emissions from fuels “listed in Table 2” of section 95121. Emissions from fuels not listed in Table 2 are

therefore not required to be reported by transportation fuel suppliers, and would therefore not be counted towards a fuel supplier's applicability threshold determination as specified in sections 95101(c)(1)-(3). Revisions made to section 95103 and 95121 were not intended to add new reporting requirements for biomethane producers or importers.

F-2. Comment: Suppliers of Transportation Fuels and Renewable Diesel

In § 95121(a), ARB is proposing a new requirement to report volumes of renewable diesel supplied. Note that renewable diesel can be blended to diesel product both at the refinery and at the terminal. Reporting (e-GGRT) forms should be modified to allow for reporting volumes from either but prevent the possibility of double-reporting of the volumes and double-obligation under Cap-and-Trade. Additionally, it is very likely that significant renewable fuel blending may occur upstream of terminal rack locations, particularly for renewable diesel which will be much more likely to be blended at refineries. Because blend percentages will vary depending on operational circumstances and product availability, it will likely be difficult to accurately track the precise movement of those renewable fuel volumes from the refinery (or bulk blending facility) to the point where the blended product is dispensed into a truck at the terminal rack. It would therefore be beneficial to add a paragraph to the § 95121 reporting procedures to clearly allow a reporting party to report the total renewable fuel blended upstream of the terminal rack and subtract it from the total blended product delivered to market.

Recommendation: WSPA recommends the following paragraph be added to follow § 95121(d)(1-4).

"(5) Refiners who blend renewable fuels at a refinery or bulk facility and displace blendstock or distillate fuel oil may report the total volume of renewable fuel blended at the refinery or bulk facility and subtract the displaced volume from the blendstock and distillate fuel oil totals reported under paragraphs (1) through (4), provided it can be demonstrated that the renewable fuel volume was not reported under paragraphs (1) through (4) by the refiner or any other party."

As an illustration of how this might work, a reporting party could blend renewable diesel at a refinery and report the total renewable diesel volume blended for the year. That party would then calculate the total CARB diesel volume delivered to market per § 95121(d)(1-4) and subtract the renewable diesel volume. The remainder would be reported as CARB diesel delivered. Following this reporting, the reporting party's verification auditors would confirm that the reporting party ensured the credit for the renewable diesel volume was not claimed elsewhere, either through clear product transfer documents or contractual agreements. (WSPA1)

Response: Staff appreciates the comment and recommendation provided by the commenter; however, we decline to make the requested change as the current language in sections 95121(d)(1) through (4) do not preclude the method described by the commenter for reporting renewable diesel. Furthermore, staff believes that the added language may cause confusion or inconsistent interpretation of the point of regulation for renewable diesel fuel. Staff understands that renewable diesel blends are chemically indistinguishable from pure petroleum diesel sold in California; therefore, staff agrees that it may be challenging to track the renewable diesel blend percentage to the point that the blended diesel product is dispensed out of a terminal rack. Because of the difficulty tracking the blend percentages of renewable diesel, staff understands that fossil diesel products blended with renewable diesel may be transacted downstream as regular (petroleum) diesel fuels, rather than as a renewable diesel blended product. Therefore, it is acceptable under sections 95121(d)(2) through (3) for the refiner to claim that the entire volume of renewable diesel blended at the refinery was used to "displace" the fossil diesel delivered out of terminal racks by the refiner as long as there is verifiable evidence that any downstream fuel suppliers receiving bulk deliveries of diesel from the refiner were purchasing regular (petroleum) diesel fuel rather than a renewable diesel blended product. Staff will draft reporting guidance to this effect.

G. MRR General Comments

Rulemaking and Implementation Process

G-1. Multiple Comments: Timing of Implementation and Non-Retroactivity

Any amendments related to implementation (effective date) of new regulations covering data collection, calculation, processing, etc. for all three regulations must be attached to a feasible implementation schedule. For example, regulations adopted in 2014 covering annual data collection and reporting requirements should apply to data collected in 2015 and reported to ARB in 2016. This lead time is necessary to allow the regulated entity to implement any changes to data collection and reporting procedures that may be necessary to comply with the new requirements. In many cases, technology must be acquired and adopted, labor resources must be on-boarded, and training must be performed to adequately and competently implement the requirements of these rules. A minimum 1 year implementation period should follow all adopted rules.

> ***Recommendation:*** For changes in the regulation that affect data collection and reporting for purposes of compliance or record-keeping, such provisions will apply to data collected and reports submitted during the calendar year following the effective date of the regulation. For example, regulatory changes that take effect January 1, 2015 shall apply to data collected in 2015 and reports submitted in 2016. (WSPA1)

Comment: I speak to you on two overarching issues: One, timing of implementation and the need for companies to adequately implement changes. Any amendments related to the implementation or effective date of new regulations covering data collection, calculation, process for this regulation as well as all the others need to be attached to some feasible implementation schedule. For example, data collected in 2015, according to presumably a new regulation, should be -- is required to be submitted to the ARB in the subsequent years. However, there is no explicit allowance for an implementation period in 2015 while those data and procedures are being implemented. So we ask that some explicit definition be made so that it's clear that data collected in 2015 effects -- the rule that's effective January 2015 effects data collected in 2015, but there is some implementation period that allows companies to implement appropriately.

Similarly, we want to make sure data collected in 2014 that is submitted in 2015 does not fall under those new regulations. That would make a regulation retroactive. That's certainly not the intent of the Board. Those are two clarifications that we think are very, very important that need to be made, especially with respect to the 2014 data submitted in 2015. (WSPA2)

Comment: The second thing I would suggest I think this is something that Mike Wang was saying is that these data changes need to be sequenced into the rulemaking and in a way so they can be accommodated properly. You don't want new data -- or data based on new collection techniques introduced in the middle of the year. If we're in 2014 and we want to adopt new data requirements for 2015, as Mike just said, time is going to be needed to figure out how to assimilate that into their data collection process for reporting in 1950. And perhaps some extra time frame should be included in the rule to allow that to happen. And subsequent to that, once they know they can get that data, it shouldn't be required to be reported until 2016 so that we don't interrupt another calendar year by giving incomplete data sets. So I hope that's helpful. Thank you very much. (CCEEB1)

> **Response:** Section 95103(h) of the regulation is used to identify new reporting requirements that may take additional time for reporters to fully implement due to the need for additional data collection or monitoring equipment, and allow reporters to use best available methods for reporting the new data in the first year of reporting. Staff believes the use of best available methods in the first year of reporting new data provides reporters sufficient time to implement changes in data collection processes and procedures. MRR has been amended several times and new reporting requirements were introduced. Providing the option for best available methods for the first year has been standard practice for each of those updates to MRR. Staff believes this policy and practice has appropriately balanced the need for conforming and accurate data and allowing for reporters to prepare to meet the full requirements of the regulation.

G-2. Multiple Comments: <u>Rulemaking and Rule Adoption Need for Process Improvements</u>

WSPA continues to be concerned with the last-minute changes proposed for inclusion in MRR regulations and others that appear either in guidance or via ARB instructions to verifiers. Most recently, for example, our members have heard from verifiers that ARB has instructed them to pass along agency-desired changes in natural gas reporting and hydrogen content (of fuels). They have also received direct, but informal requests from ARB to correct liquid CWB throughput volumes for temperature changes. Notwithstanding the concerns that arise when the ARB announces proposed changes through verifiers or other ad-hoc means, these changes must, for consistency and clarity, be raised in a more formal regulatory context.

As a practical matter, a truncated process that involves Board adoption of proposed regulatory changes during the same week the formal 45-day public comment period closes, and then relies on post-hearing changes to address issues identified during the public comment period, will inevitably lead to confusion and failure to resolve important issues. This is certainly not the process envisioned in the California Administrative Procedures Act (APA). While informal, pre-rulemaking dialogue is helpful to identify and resolve some issues in advance of the formal rulemaking process, it should not be used as a substitute for a meaningful formal rulemaking process. Both ARB and the regulated community need to have adequate time to analyze proposed changes, understand their potential impact on facility operations and identify additional changes that may be necessary to mitigate those impacts. For future rulemakings, WSPA urges ARB to adhere to the formal rulemaking process established by the APA and allow sufficient time to address public comments ***in advance*** of Board adoption rather than through abbreviated post-hearing changes.

In addition, ARB recently indicated that it cannot make substantive post-hearing changes to regulations unless they pertain to the regulatory language proposed in the original 45-day public notice. ARB asserts that such changes would require another round of rulemaking and a separate 45- day public notice and comment period. Yet ARB announced in a September 8, 2014 e-mail that it now seeks to incorporate in the MRR regulation the above noted temperature adjustment for liquid throughputs by way of post-hearing changes and a 15-day public notice and comment period. It is not clear how ARB can consider this change to fall within the scope of the 45-day notice while at the same time rejecting other important technical fixes, such as necessary revisions to holding limits, or revising requirements concerning corporate associations. If ARB can reconcile a change in reporting requirements for liquid throughputs in a post-hearing package with the “sufficiently related” standard in the APA, then other technical changes should also be eligible for the post-hearing 15-day process.

In this regard, WSPA specifically requests ARB include in its post-hearing changes revisions to MRR Section 95103(k)(10) that would allow operators to demonstrate through engineering methods that a product meter is accurate and, if approved by their verifier, data from the meter should not be subject to a finding of non-conformance. WSPA members have expressed to ARB in the past their concerns that a qualified positive verification in this instance is neither appropriate nor acceptable because the classification is, in and of itself, pejorative.

> ***Recommendation*****:** ARB should establish a consistent practice of incorporating technical changes to existing regulations through the formal rulemaking process.

This would allow needed improvements to be implemented in a more transparent fashion.

ARB should also convene periodic (perhaps every 60-90 days) meetings with the regulated industry, verifiers and interested stakeholders to identify issues that COULD BE addressed in the future (either in guidance or future rulemaking). Periodic meetings would surface issues at a much earlier stage in the process and reduce the frequency with which last minute guidance or rulemaking is needed. Such an improvement would: 1) assist in building in time to review possible impacts, understand how impacts could be addressed or mitigated, provide input to the ARB and then make needed changes to facilitate implementation of the regulation; and 2) improve communication between and among ARB, stakeholders and qualified verifiers. Finally, these process improvements would reduce the need for the abbreviated regulatory process that has recently been the norm and reduce the tendency to clarify rule ambiguities through guidance. (WSPA1)

Comment: Secondly, with respect to process, there are some process improvements that I've talked with staff and I think we're in pretty good consensus that we need a better interaction amongst staff. There have been a series of what we will consider relatively short fused last-minute changes that have been proposed that we think need additional work. The staff has made some suggestions as part of the resolution. We'd like to make it very clear that should there not be enough time to work within the 15-day package, that that issue might be deferred for the future. Again, we're talking about temperature correction. (WSPA2)

Comment: My comments are going to follow, not necessarily that closely, but they will follow Mike Wang's comments with regard to process concerns. These changes in data collection can be extremely complicated at large facilities. When the request for data to be collected changes, then procedures need to be placed to get that data. In fact, enough time is needed so they can be sure they can get the data in sufficient quantity and sufficient quality to meet what a verifier might say is absolutely critical. When changes are made toward the ends of the 45-day process that come in with new data requirements, we understand it's not meant to be punitive, and we understand that the staff is just doing its job. But practically speaking, until the refinery -- in this case, the refinery has a chance to try to implement this through some reasonable time frame to know whether or not it will even work, then we'll lose -- if the rule is then adopted, then we all lose the opportunity to cure it until we wait several months down the road.
So let me just offer two thoughts to you. Recognizing the complexity of significant data changes to major industrial facilities, however simple they may sound on black and white on a piece of paper, we would suggest that, first, before it is inserted into the proposed rulemaking, that somebody, somewhere be certain that the people that are going to have to comply with it are able to comply with it. And if they come up with reasonable explanations as to why they will have difficulties, it would be good if they would be recognized. But if you don't have adequate time at the front end of the process, it's going to be very difficult to do. (CCEEB1)

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 in early 2014 on areas where regulatory clarification was needed and on concepts for potential regulatory amendments. In February through May of 2014, staff released guidance and gave presentations to reporters, which included the majority of the clarifications that were made in proposed amendments. The proposed amendments largely do not introduce new requirements, but serve to codify guidance given by staff earlier in the year. In addition, staff held a public workshop on June 5, 2014 to discuss draft regulatory changes released prior to the workshop. Staff crafted the proposed amendments submitted in the 45-day regulation based on stakeholder feedback as a result of that workshop and extensive stakeholder outreach. 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. 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.

For the comment referring to potential changes to the temperature adjustments as part of a 15-day comment period, ARB staff did not make changes to the requirements for liquid throughputs for the reasons stated and additional technical constraints.

For the comment requesting use of engineering methods for determining product data accuracy in 95103(k)(10), this section was not included in any of the proposed updates so the comment is beyond the scope of the revisions. Furthermore, product data meters must be calibrated as specified to ensure accuracy as these data are used to determine allowance allocations. Use of engineering data is not appropriate or sufficient in this situation.

Section 95103(h) of the regulation is used to identify new reporting requirements that may take additional time for reporters to fully implement due to the need for additional data collection or monitoring, and allow reporters to use best available methods for reporting the new data in the first year of reporting. Staff believes the use of best available methods in the first year of reporting new data provides reporters sufficient time to implement changes in data collection processes and procedures.

G-3. Comment: Is § 95103 (h)(1) a reference to 95103 (m)(1)(A)? 95103 (m)(1)(A) [as shown in the proposed regulation] does not appear to exist. (WSPA1)

Response: This was a typographical error and should have read 95153(m)(1)(A). As part of a 15-day change, the entire sentence was removed because it was no longer necessary after incorporating an option to use engineering estimates based on best available data for estimating compressor start-up emissions under section 95153(m)(1)(A).

G-4. Comment: § 95103 (l): We do not believe the phrase "may elect to" should be changed to "must". Since there is no "missing data" provision in the regulation, operators should have the flexibility to include or exclude data at the operator's discretion. However, if an operator is required to include data that is not within ±5% accuracy, then ARB must confirm that the data will not be subject to a finding of non-conformance.

WSPA needs more clarification in the interpretation of: 1) temporary use of meters in case of equipment failure; 2) ability to exclude CWB data following verification without risk of non- conformance; and 3) ability to exclude CWB data in advance if included or specified in the company's monitoring plan. (WSPA1)

Response: Regarding the first part of the comment, it was necessary to change the term "may elect" to "must" because under the regulation reporters are required to submit accurate *covered* product data, as specified in section 95103(k). Data that do not meet these, and other relevant requirements, cannot be included as valid covered product data and are considered inaccurate.

To address the comment regarding clarification for use of meters, excluding CWB data following verification, and excluding CWB data in advance, this comment is outside the scope of the regulatory amendments. However, ARB staff will provide guidance to address these questions in early 2015.

G-5. Comment: § 95103 (m)(1) appears to imply that § 95103 (m)(2) and (3) are only applicable to facilities proposing a permanent change to a lower-tier emissions or product data reporting method.

***Recommendation*:** If WSPA's interpretation is correct, we recommend the following changes (in red) to add clarity:

(m)(2): When proposing a permanent change to a lower-tier in a monitoring or calculation method to the Executive Officer, an operator or supplier must indicate why the change in method is being proposed…, and include a demonstration of differences in the data estimated under the two methods.

(m)(3): When permitted, a change to a lower-tier in method must be made after the completion of monitoring for a data year...except in the circumstances described in part (m)(4). (WSPA1)

Response: The commenter's interpretation of this provision is incorrect. Section(m)(3) must be applied to a change in methodology regardless of whether it is to a higher or lower tier. This means that the change must occur at the beginning of a data year (not mid-year), except as described in section 95103(m)(4).

Section 95103(m)(2) applies only to changing to a lower-tier method because section 95103(m)(1) states that changes to a lower-tier method must be approved in advance by the Executive Officer. When an operator changes to higher-tier method they must notify ARB, but they are not required to get prior approval.

Staff will provide guidance to fully explain the process regarding method changes allowed under section 95103(m).

G-6. Comment: § 95103 (m)(1) is amended to limit the ability of reporting entities to change from a lower tier calculation method to a higher tier calculation method following notice. WSPA believes entities should be able to improve their data monitoring or calculation at any time during the year. Improved data is of value to both the entity and ARB.

Recommendation: WSPA recommends the following changes (in red) to the second sentence in this provision:

Permanent improvements to emissions monitoring or calculation methods do not require approval in advance by the Executive Officer ~~however, the operator or supplier must notify ARB prior to January 1 of the year the new method is implemented.~~ (WSPA1)

Response: The purpose of the revision to section 95103(m)(1), requiring annual notification if new methods are used, is necessary to provide certainty and data integrity for the ARB, reporters, and verifiers. This requirement is also reinforced by section 95103(m)(3), which requires that any changes be implemented at the beginning of a data year (except as specified otherwise). Although there may be potential benefits to allowing ongoing updates to data calculation methods, ongoing method changes are more difficult to validate and may require multiple analyses to ensure accuracy. Also, changes could potentially be performed throughout the course of the year to select methods that are advantageous from a reporting perspective, and not necessarily implemented solely for accuracy improvements. Finally, the use of different methods throughout a year makes it more difficult to identify if changes in facility emissions or production data throughout the year (and year-to-year) are due to changes in actual emissions or production, or are simply the result of using new methods. ARB also strives to ensure data consistency across entities in the same sector and the same level of accuracy across all sectors. For these reasons, ARB staff declines to make the requested change.

G-7. Comment: New Requirements for Changes in Methodology, 95103(m)(4)

As a small business and small California refinery, Kern is not supportive of proposed revisions to Section 95103 that would require the operator of a petroleum refinery and/or fuel supplier to seek approval and/or make notifications in advance of the reporting deadline when using interim data collection procedures. Provisions for how to substitute missing data are already included in the MRR, conformance with which would be captured within the third-party verification process. Additional notification that a reporter has used these provisions is unnecessary and burdensome. (KERN1)

> **Response:** There are several components to the revisions to section 95103(m)(4). The first emphasizes the existing requirements in 95129(h) and 95129(i) for unforeseen breakdowns, and does not impose new requirements. The second component describes what must be done if temporary methods are used that are unrelated to breakdowns. Next, the provision describes what action must be taken if a "temporary" method exceeds 365 days. And finally, the provision describes accuracy requirements and the consequences if they are not met.
>
> The proposed amendment associated with the use of a temporary method not associated with an unforeseen breakdown only requires that ARB be notified of the temporary method, affected data, and how long the temporary method was used. This requirement is necessary to both ensure the overall integrity of the "temporary" data, and to provide a check against the ongoing or unnecessary use of temporary data to avoid implementing the full requirements of the regulation. It is correct that verifiers are trained to identify that appropriate missing data provisions are applied. However this is done after the reporting deadline, which makes potential corrective actions more challenging than if notification is received prior to the deadline. This situation can create the potential for inaccurate and non-compliant data submissions. Therefore, staff maintains that the revisions as shown are necessary
>
> Also, in the regulation updates, if a temporary method is used for more than 365 days, reporters must have the method approved as a permanent method by the Executive Officer. This allows ARB staff to fully evaluate the temporary method, identify if other options are available, and ensure that the method is adequate for meeting the reporting requirements. This action provides assurance to the reporter and the verifier that the ARB has reviewed, accepted, and approved the method. This update is needed to prevent the unbounded use of temporary methods, and to provide certainty to reporters and verifiers. Because of this, staff had determined that the provisions must remain intact, as they are.

G-8. Comment: Comments on MRR and COI Fee
Definition of Public Wholesale Water Agency

In the October 2013 revision to the Cap-and-Trade regulations, ARB included a definition specific for public wholesale water agency which recognizes that Metropolitan is not an EDU, and requires a new definition that more accurately reflects its actual activities as a public water agency. This definition of public wholesale water agency, which should refer to the Statutes of 1969, instead of the Statutes of 1960, aligns with Metropolitan's inclusion in and use of the NAICS Code for Water Treatment and Distribution in its MRR submittals. Although ARB states that the proposed amendments to the regulations for Cap-and-Trade, MRR, and COI Fee are designed to align definitions, ARB has not included the definition of public wholesale water agency in the MRR and COI Fee regulations. Metropolitan requests ARB to add the definition of public wholesale water agency to both the MRR and COI Fee regulations. (MWATER1)

> **Response:** Staff declines to make this change. The term "public wholesale water agency" is not relevant to, or used in, MRR or the COI Fee Regulation, and is therefore not needed.

G-9. Comment: PG&E supports the ARB's effort to update the MRR and COI regulations. In developing the amendments, ARB staff presented its initial ideas for discussion at a public workshop held on June 5. PG&E participated actively at the workshop and incorporates its comments by reference.[18] PG&E acknowledges that these comments were addressed and thanks ARB staff for considering them. (PGE1)

> **Response:** Thank you for the support.

H. Cost of Implementation Fee Regulation Comments

H-1. Multiple Comments: MRR Section 95122(d)(2)(E)—Data Reporting for Local Distribution Companies: Language Clarification And Consistency With Cost of Implementation Fee Regulation

PG&E requests clarification or makes recommendations as follows for this section, which impacts both the MRR and COI:

a. The proposed amendments require local distribution companies to provide "the annual energy in MMBtu [million British thermal units] delivered to residential, commercial, industrial, electricity generating facilities, **and other end-users** (emphasis added) not identified as residential, commercial, industrial or electricity generating facilities." PG&E supports ARB's goal to include the data required to support the COI within this MRR report. PG&E requests clarity to understand what sources are included in "other end-users" in the proposed amendment.

b. PG&E requests clarity on reporting California end-user data. The Energy

[18] Krausse, M. 2014. *Informal Comments on the Air Resources Board's Proposed Changes to the GHG Mandatory Reporting Regulation*. Pacific Gas and Electric. Retrieved from http://www.arb.ca.gov/lists/com-attach/2- mrr-2014-ws-UyMHZlw4Aw8GYwNs.doc

Information Administration (EIA)-176 data required per 40CFR§98.406(b)(13) are reported in million standard cubic feet (MSCF). It is unclear what conversion factors would be applied to convert MSCF into MMBtu. Additionally, PG&E's billing system uses Therms as the unit of measure for customer deliveries. Billing data, when parsed into the proposed four customer data categories, will not be consistent with the EIA report.

PG&E requests clarity on how PG&E customers who pass the natural gas to other facilities will be reported (e.g. Sacramento Municipal Utility District) to ARB. (PGE1)

Comment: 4. Data Reporting for Local Distribution Companies

SoCalGas and SDG&E request clarification with respect to MRR Section 95122(d)(2)(E) — Data Reporting for Local Distribution Companies: Language clarification and consistency with Cost of Implementation Fee regulation

Specifically, the 45-day amendments require local distribution companies to provide "the annual energy in MMBtu [million British thermal units] delivered to residential, commercial, industrial, electricity generating facilities, and other end-users (emphasis added) not identified as residential, commercial, industrial or electricity generating facilities." SoCalGas and SDG&E request that ARB clarify what sources are included in "other end-users" in the proposed amendment. (SEMPRA1)

Response: Staff disagrees with the commenters that other end-users should be defined. The U.S. EPA Rule on Mandatory Reporting of Greenhouse Gases includes four end-use categories for reporting natural gas delivered by local distribution companies: residential consumers; commercial consumers; industrial consumers; and electricity generating facilities. The Fee Regulation includes the term "other end-users" to ensure that local distribution companies report all natural gas delivered to end-users. Staff believes that listing other specific end-users and eliminating the term "other end-users" would limit the end-users reported and not capture every end-user.

The Fee Regulation contains several definitions that support the reporting of natural gas, including "End User," "Local Distribution Company," and "Natural Gas Supplier." "End User" does not include natural gas that is used for the purposes of retransmission or resale. Further, "Local Distribution Company" means a company that owns or operates distribution pipelines. Finally, "Natural gas supplier" means a the local distribution company or interstate pipeline that owns or operates the distribution pipelines that physically deliver natural gas to end users. Staff believes the Fee Regulation is clear regarding the reporting of natural gas.

H-2. Comment: MRR § 95113 (l)(3), which appears to support the COI regulation, requires that "for transportation fuel products listed in Table MM-1, the operator must report CARBOB as RBOB…". The term "transportation fuel products" does not appear in table MM-1 and is not defined in ARB regulations. Please specify what products in Table MM-1 are referenced by this provision.

Also, it seems this provision is just trying to identify gasoline-range fuel used in California and blended with ethanol. By definition, this is only CARBOB. Conventional gasolines and CBOBs would only be exported outside of California and the other fuels (i.e., distillates) are not blended with oxygenates, in which case it is not clear why Table MM-1 is referenced at all in this provision. Moreover, § 95113 (l)(3) is even more confusing in light of proposed § 95113 (m)(1). How is (m)(1) different from (l)(3)? (WSPA1)

> **Response:** As part of the 15-day changes, staff removed the text in section 95113(l)(3) referred to in this comment. It was removed because the text was redundant to section 95113(m)(1).

H-3. Comment: COI Fee Regulation Applicability to Electricity Generating Facility

To ensure that the appropriate fee is being paid, PG&E recommends that ARB include language that allows dual-fuel electricity generating facilities to subtract the net power generated by the facility from California diesel fuel, as described below.

PG&E owns and operates the Humboldt Bay Generating Station (HBGS) that uses ten California diesel and natural gas dual-fuel reciprocating engines with a nominal output of 163 megawatt (MW). HBGS pays a COI fee for every gallon of diesel received *and* for each megawatt-hour (MWh) of net power generated by the facility. This results in excess COI fees being paid annually by the facility. Although normal operation only results in 1 to 2 percent of the power being generated from diesel fuel, there may be situations when natural gas supply is curtailed and electricity generating units will operate for an extended period on diesel fuel. To ensure that the appropriate fee is being paid, PG&E recommends that ARB include language that allows dual-fuel electricity generating facilities to account for the net power generated by the facility from California diesel fuel. (PGE1)

> **Response:** This comment is outside the scope of the proposed amendments. However, section 95201(a)(4) of the AB 32 Cost of Implementation Fee Regulation states: "…Fees shall be paid for each megawatt-hour of net power generated by combustion of natural gas, coal or other fossil fuels (except California diesel) at a grid-dedicated, stand-alone electricity generating facility in California, and reported pursuant to section 95112 of the Mandatory Reporting Regulation…" Pursuant to this section, no fees should be assessed for power generated from California diesel. In the case where an entity believes that fees were improperly calculated, the commenter should contact ARB staff to correct the error in the amount of fees they were assessed.

H-4. Comment: WSPA has reviewed the proposed changes to the COI regulation and offers the following comments and recommendations.

Consistency in Requirements – Record Retention (§ 95204(i)).

The MRR and COI record retention requirements should be made consistent. § 95204(i) should just reference MRR (§ 95105) which specifies a 10 year retention requirement, but requires submittal within 20 days following a request, instead of 5, and allows the records to be kept out of state. There is no need for the COI regulation to be different, much less more restrictive in these areas.

> ***Recommendation*****:** Modify this section to read, "Entities subject to this sub-article must maintain copies of the information reported pursuant to the applicable sections of the Mandatory Reporting Regulation~~. and provide them to an authorized representative of ARB within five business days upon request. Records must be kept at a location within the State of California for five years~~."

Clarification Needed

WSPA requests clarification on the following technical issues.

- § 95201(c) references B100 and R100 for biodiesel and renewable diesel, respectively. The terms in the MRR have been changed to recognize that these may be B99+ and R99+ in § 95121(d), Table 2. The MRR terms are more accurate and the COI regulation should be further amended to incorporate the MRR terms.

- The emission factors in § 95203(d) are proposed to be removed and instead Table MM-1 is referenced for entities reporting pursuant to § 95204(e) – fuel providers. An averaging technique is mentioned, but it is unclear which fuel grades will be included from Table MM-1, how they link to gasoline and diesel, and how these grades will be averaged. This process needs to be explicitly described so that regulated parties understand how ARB will use the data.

- § 95204(b) specifies that all entities subject to this sub-article are required to certify reports pursuant to the requirements of MRR. ARB should be specific as to which sections in MRR are being incorporated by reference.

What is the justification for the significant increase in the emission factor and corresponding fee for catalyst coke? We see no basis for the change since the regulation was first adopted. (WSPA1)

> **Response:** These comments address the Cost of Implementation Fee Regulation. These comments are addressed in the Cost of Implementation Fee Regulation Final Statement of Reasons.

I. Cap-and-Trade Regulation Comments

I-1. Comment: Corporate Associations

WSPA members have participated in a joint industry group coordinated by the California Manufacturers & Technology Association seeking a clear compliance pathway to satisfy the corporate association disclosure requirements included in the C&T regulation. WSPA members have filed numerous comments over the past 18 months expressing grave concerns over the expansion of the disclosure requirements to non-registered entities that became effective on July 1, 2014. WSPA is grateful for ARB's issuance of guidance on July 29 in response to these concerns permitting companies to file their SEC Form 10-K list of subsidiaries to satisfy the disclosure requirements as they apply to unregistered entities. WSPA supports the Joint Industry Proposal for changes to § 95830, 95833, 95912 and 95923 presented to ARB staff on August 22, 2014. In particular, WSPA urges ARB to retain disclosure of the SEC Form 10-K list of subsidiaries as a compliance option. WSPA also supports changes to the regulatory investigation disclosure requirements included in § 95912 that must be included in an auction application attestation. Even if it applies to the list of SEC affiliates, the requirement remains too broad, creates an undue burden on industry and provides ARB with limited value. WSPA recommends limiting the disclosure of regulatory investigations to the auction participant only and to adjust the time frame from 10 years to 5 years in a manner consistent with most statutes of limitation.

While we would prefer for ARB to include the Joint Industry Proposal as a whole in the regulation to reflect the full spectrum of compliance options, we understand ARB is considering, as an interim step, making certain post hearing changes that link the regulatory requirements to updated guidance. It is our understanding that the guidance would complement the post-hearing changes until such time that the regulation can be re-noticed to incorporate the Joint Industry Proposal. We appreciate ARB's collaboration with the Joint Industry Group toward a workable solution on this issue.

ARB also proposes to change the timeframe for updating information on employee and indirect corporate associations not registered in CITSS or a linked jurisdiction to an annual reporting requirement [§ 95830 (f)(1)]. WSPA supports this change. We further recommend ARB include reporting of consultants and advisors in this section as shown below (in red).

Recommendation:

(f) Updating Registration Information.

(1) Registered entities must update their registration information as required by any change to the provisions of section 95830(c) within 30 days of the changes becoming effective. When there is a change to the information registrants have submitted pursuant to section 95830(c), registrants must update the registration information within 30 calendar days of the change unless otherwise specified below. Updates of information provided pursuant to

section 95830(c)(1)(I) ~~and (c)(1)(J)~~ may be updated at least annually ~~each calendar quarter~~ [this prior language was struck in the 45 day change] instead of within 30 calendar days of the change. If changes in information submitted pursuant to section 95830(c)(1)(H) are related to entities registered in the Cap-and-Trade Program, the information must be updated within 30 calendar days. If changes in information submitted pursuant to section 95830(c)(1)(H) are related to entities which are not registered in the Cap-and-Trade Program or in a GHG ETS to which California has linked pursuant to sub-article 12, the information must be updated at least annually, instead of within 30 calendar days of the change.

Consistency in Terms

There is an inconsistency in terms between § 95830(c)(1)(H) and the changes ARB has proposed in § 95833 (b),(d) and (e). We believe the use of the generic term "corporate association" in § 95830 (c)(10(H) could unintentionally be applied to indirect corporate associations where neither are registered in CITISS. This seems contrary to ARB's intent.

Recommendation: WSPA recommends the following language change (in red) to § 95830(c)(1)(H).

(H) Identification of all other registered entities ~~pursuant to this article~~ with whom the entity has a ~~corporate association,~~ direct corporate association, or indirect corporate association pursuant to section 95833, and a brief description of the association. An entity completing an application to register with ARB and for an account in the tracking system must provide all applicable information required by section 95833.

Holding Limits

WSPA continues to be concerned that the current holding and purchase limits are extremely restrictive. The outcome will likely be a constrained market that limits participants' flexibility to comply at the lowest incremental cost. The conservatively low holding/purchase limits disproportionately impact those entities with large compliance obligations, particularly those sharing holding limits and purchasing limits with one or more directly related entities. Furthermore, this problem will be compounded in 2015, since the compliance obligations of fuel providers are typically much higher than the increase in the holding limit. These constraints leave such an entity no alternative other than to prematurely move large quantities of compliance instruments to its compliance account, rendering useless the multi-year compliance period flexibilities and exposing the company to significant risks of stranded assets in the event of operational or corporate activity changes over the compliance period.

As you are aware, the Emissions Market Assessment Committee (EMAC) recognized these concerns in its November 8, 2013 report and offered two possible recommendations: 1) consideration of adjusting or scaling the holding/purchase limits based upon the compliance obligation for a particular entity, and 2) consideration of additional flexibility in movement of compliance instruments from the compliance account, including allowing a portion of the compliance instruments to be removed and offered for resale into the market. The opinion of the EMAC was that making these modifications would provide additional flexibility to the regulated entity, while still preserving the goal of preventing market manipulation.

> ***Recommendation:*** ARB should adopt the recommendations prepared by the EMAC. ARB should place specific emphasis on scaling of holding/purchase limits that reflects the size of the entity's obligation, and provides increased flexibility and control by the regulated entity with respect to management of the accounts. (WSPA1)
>
> **Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2014 Cap-and-Trade Regulation Final Statement of Reasons.

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

Chapter V of this FSOR contains all comments submitted during the 15-day comment period, with ARB's responses. The 15-day comment period for additional proposed amendments commenced on October 2, 2014, and ended on October 17, 2014.

ARB received 11 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: http://www.arb.ca.gov/regact/2014/ghg2014/ghg2014.htm

This rulemaking is for amendments to the ARB greenhouse gas mandatory reporting program. However, a few comments were submitted to this rulemaking which relate to separately noticed Cap-and-Trade and Cost of Implementation program rulemakings, which are outside the scope of the proposals identified in the Staff Report, Notice 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.

A. LIST OF COMMENTERS

Table V-1

Abbreviation	Commenter
CCEEB2	Gerald Secundy, California Council for Environmental and Economic Balance Written Testimony: 10/17/2014
IEPA2	Amber Blixt, Independent Energy Producers Association Written Testimony: 10/17/2014
MSR2	Martin Hopper, M-S-R Public Power Written Testimony: 10/16/2014
NCPA2	Susie Berlin, Northern California Power Agency Written Testimony: 10/17/2014
POWEREX1	Nicolas Van Aelstyn, Powerex Corp Written Testimony: 10/17/2014
SCE2	Frank Harris, Southern California Edison Written Testimony: 10/17/2014
SCPPA2	Tanya DeRivi, Southern CA Public Power Authority Written Testimony: 10/15/2014
TESORO1	Miles Heller, Tesoro Corporation Written Testimony: 10/17/2014

Abbreviation	Commenter
TRANSA1	Braydon Boulanger, TransAlta Written Testimony: 10/16/2014
WPTF2	Clare Breidenich, Western Power Trading Forum Written Testimony: 10/17/14
WSPA3	Catherine Reheis Boyd, Western States Petroleum Association Written Testimony: 10/17/2014

B. Electric Power Entity Requirements

Transmission Loss Factor

B-1. Multiple Comments: Transmission Lines Losses are Correctly Calculated at 1.0 Under Certain Conditions

The Proposed Amendments to Section 95111(b)(2) would have mandated a single transmission loss factor of 1.02 for all specified sources, regardless of the conditions under which the electricity is delivered to California. The 15-Day Changes correctly acknowledge the fact that line losses associated with these imports may be addressed in an alternate manner, and allows the reporting entity to utilize 1.0 "if the reporting entity provides documentation that demonstrates to the satisfaction of a verifier and ARB that transmission losses (1) have been accounted for, (2) are supported by a California balancing authority, or (3) are compensated by using electricity sourced from within California." Several stakeholders, including M-S-R, presented evidence to CARB regarding the myriad ways that entities handle transmission losses, including as part of their contractual arrangements for delivery of the power to California. The proposed modifications would meet CARB's stated intent of ensuring that line losses are accurately captured and reported, but would avoid the perverse outcome of over-reporting electricity imports. CARB should adopt the changes to section 95111(b)(2) as proposed in the 15-Day Changes. (MSR2)

Comment: Transmission Loss Factors

The 15-Day Changes to the calculation of the loss factor for specified imports should be approved. As originally proposed, the amendment to section 95111(b)(2) would have required the 1.02 transmission loss factor for all specified imports, regardless of how the losses are actually accounted for by the reporting entity. The 15-Day Changes reflect stakeholder feedback regarding the various contractual and other arrangements between parties that account for transmission losses, and strikes the unilateral application of a 2% adder to all imports; these changes should be adopted. As revised, this section would allow the reporting entity to apply the 1.0 loss factor under certain conditions, including upon providing "documentation that demonstrates to the satisfaction of a verifier and ARB that transmission losses (1) have been accounted for, (2) are supported by a California balancing authority, or (3) are compensated by using electricity sourced from within California." This revision addresses Staff's desire to ensure that all imports – including line losses – are properly counted, without imposing additional compliance burdens on reporting entities, or overstating the actual emissions imported into California. The change to the proposed amendments should be approved by CARB. NCPA appreciates Staff's recognition of the myriad contractual arrangements used by stakeholders, and looks forward to working with CARB on regulatory guidance regarding the necessary documentation and demonstration CARB requires. (NCPA2)

> **Response:** Thank you for your support and for working with staff to finalize the proposed regulatory language.

Calculating Specified Source Emission Factors

B-2. Comment: Use of EIA Data

The 15-Day Changes include necessary clarifications regarding the use of EPA versus EIA generation data for determining specified source emission factors. These changes will facilitate entity reporting and ensure that the California MRR and the EPA reporting requirements are harmonized, even after implementation of the EPA's Clean Power Plan Proposed Rule. (NCPA2)

> **Response:** Thank you for your support.

B-3. Multiple Comments: TransAlta understands that these new amendments are intended to apply only when an importer wishes to register a particular generating unit within a larger specific facility; however, the regulatory changes have not made this clear. TransAlta therefore requests that ARB provide guidance explaining that these new requirements apply only in the case when a unit-specific emission factor is requested, reinforcing that new this level of granularity is not mandatory when reporting at the facility level.

TransAlta further requests ARB to clarify that when an importer is registering at the unit level, they may submit only the minimum contract terms necessary to demonstrate that the specific unit was identified as the intended specified source, while permitting the redaction of any confidential information. This clarification should also establish how reporting entities are expected to demonstrate proof of direct delivery within the current *Specified Facility Reporting Spreadsheet*. TransAlta proposes that a single e-tag showing delivery from the unit to California should be acceptable. TransAlta believes these issues can be appropriately addressed in guidance, or through a modified specified source registration form.

ARB's proposed changes introduce additional requirements for registering a specified source that are beyond the procedures currently agreed to by power marketers when transacting specified source power. As these are new requirements, TransAlta asks ARB to issue the clarifying guidance suggested above and ensure these amendments are not retroactive. (TRANSA1)

Comment: The Independent Energy Producers Association (IEP) submits these comments on the Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, released October 2, 2014. In these proposed "15-Day Changes" the CARB has proposed new language in Section 95111(b)(2) that reads as follows:

> *In order to register a specified unit(s) source of power pursuant to section 95111(g)(1), the reporting entity must provide to ARB unit level GHG emissions consistent with the data source requirements of this section and net generation data as reported to the EIA, along with contracts for delivery of power from the specified unit(s) to the reporting entity, and proof of direct delivery of the power by the reporting entity as an import to California.*

As IEP understands it, the proposed language above is only meant to apply to importers that voluntarily wish to register a resource under a "unit" specific emissions factor rather than a facility specific emission factor. IEP believes that the proposed language above would benefit from additional clarity in the Final Statement of Reasons (FSOR) document to indicate that the requirements above (i.e. to submit contractual information) do not apply to in-state facilities, or entities that use facility-specific emission factors. Rather these requirements only apply to entities that voluntarily propose to register using a unit-specific emission factor. Additional explanation in the FSOR will be helpful to clarify that CARB is not imposing new, additional requirements on in-state generators that are already subject to the Mandatory Reporting obligation and out-of-state resources that will continue to use a facility-specific emissions factor.

Provided that these clarifications are made, IEP is generally comfortable with CARB's proposal: for those that voluntarily request a unit-specific emission factor, the CARB may require the submission of contractual information related to the delivery of imported power from the specified unit(s) to the reporting entity. However, IEP suggests that any such contractual information provided to the ARB shall be held in confidence by the ARB until such time as the contract information is made publicly available by any governing body, utilities commission, or other regulatory body responsible for approving the power contract. Alternatively, CARB should work with the entities that are providing contractual information to ensure that a sufficient cover of confidentiality is provided. (IEPA2)

Comment: Proposed MRR § 95111(b)(2) (Oct. 2, 2014). Powerex understands that this new requirement is intended to apply only in the case that an importer of electricity wishes to register and apply for an emission factor for a particular "electricity generating unit" within a larger facility, as that term is defined in MRR section 95102(a)(138). Powerex understands that this new language is not intended to apply to the application for "electricity generating facilities" as defined by section 95102(a)(137).

It appears that the newly proposed requirement for contracts and proof of delivery is to establish that an EF for the unit is needed for the upcoming import filing, and thus that ARB won't need to go through the process of establishing an EF that won't actually be used. If this interpretation is correct, Powerex recommends that CARB limit the magnitude of the data request to the minimum required to establish that the EF will be used in the upcoming import report: namely, a redacted contract identifying both the unit and documenting that the EPE has rights during the reporting year, as well as a single NERC e-tag demonstrating direct delivery.

Powerex respectfully requests that ARB confirm the above interpretations of the language proposed for addition to MRR section 95111(b)(2) in its Final Statement of Reasons for these amendments. Thank you very much for your consideration of Powerex's comments. (POWEREX1)

Comment: Requirements for registration of specified sources

New language introduced in the 15 day proposed amendments in section 95111(b)(2) states "In order to register a specified unit(s) source of power pursuant to section 95111(g)(1), the reporting entity must provide to ARB unit level GHG emissions consistent with the data source requirements of this section and net generation data as reported to the EIA, along with contracts for delivery of power from the specified unit(s) to the reporting entity, and proof of direct delivery of the power by the reporting entity as an import to California."

WPTF understands from conversations with CARB staff that these new requirements are intended to apply only in the case that an importer wishes to register, and have an emission factor calculated for, a particular generating unit within a larger facility, rather than the facility as a whole. This is not clear from the newly introduced language, due to the fact the elsewhere the regulation defines and refers to specified sources, rather than specified *unit* sources. We therefore request that CARB provide clarification in guidance that explains that these new requirements apply only in the case that a unit-specific emission factor is requested. Additionally, it would be helpful for CARB staff to articulate the problem that the new requirements are intended to address (e.g. a difficulty in disentangling unit- specific data from the Environmental Protection Agency's facility emissions data).

We also request CARB to address in guidance several complications that arise from these new requirements:

- An importer who is not the facility owner or operator will not have access to emissions and generation data for the unit in question unless provision of that data has been expressly required by the terms of the contract. As this is a new requirement, it would not be fair to apply it retroactively to 2014 imports. CARB should therefore explain how a unit-specific emission factor will be calculated in the event that the importer is unable to provide emissions and generation data.

- We are concerned about the need for an importer to provide full contracts containing confidential information to CARB. We therefore urge CARB to clarify that the importer may redact confidential information, and submit only the minimum documentation of contract terms necessary to demonstrate that the specific unit was identified as a specified source.

- Similarly, an importer should be required to submit only the minimum documentation necessary to demonstrate direct delivery during the previous calendar year. For example, a single e-tag showing delivery from the unit to California, or if the delivery is not tagged, revenue meter data reflecting generation for a single day from a California balancing authority, should suffice. (WPTF2)

  Response: Thank you for your comments. The language in section 95111(b)(2) referred to in the comments is not a new requirement, but serves to clarify an existing provision that allows for entities to voluntarily register emission factors for specified source units of power. The requirements for registering facility emission factors remain unchanged. If an entity cannot provide sufficient evidence to substantiate the use of a specified source unit of power, the entity may use the facility emission factor provided by ARB for that facility. It is pertinent that the reporting entity can show direct delivery of power from a specific unit in order to claim an emission factor assigned only to that unit.

  While staff believes the proposed 15-day language clearly applies only to those specified unit sources of power, staff will clarify the applicability of this provision in guidance it plans to release in early 2015. In addition, staff will provide guidance related to the evidence that a reporter will need to provide to substantiate the use of an emission factor for a specified unit source of power. Staff will work with entities that submit contracts to protect any information marked as confidential. If approved, this requirement would become effective January 1, 2015 and be applicable to 2014 data reported in 2015.

B-4. Comment: SCE agrees that for specified facilities or units whose operators are not subject to reporting under the MRR, the emissions shall be based on the GHG emissions reported to the U.S. EPA. Thus under Section 95111(b)(2)(B), the strikeout should be removed so that the section reads:

> 95111(b)(2)(B) For specified facilities or units whose operators are not subject to reporting under this article, Esp shall be based on GHG emissions reported to ***the US EPA pursuant to 40 CFR Part 98***.Emissions from combustion of biomass derived fuels will be based on EIA data until such time the emissions are reported to the US EPA.

Under 95111(g), the proposed new sentence states that the ***operator*** is responsible to register a specified source. SCE suggests that the term ***operator*** (two occurrences of such in this sentence) should be replaced with the phrase ***reporting entity*** because the reporting entity, not the operator, is responsible for registering specified sources of electricity.

Also under 95111(g), the proposed new sentence states, "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." SCE believes the opening phrase of this sentence references the wrong MRR section. The registration of specified sources is governed by this same section 95111(g) (in the preceding sentence to the proposed new sentence). It is not governed by section 95103(e), which specifies the reporting deadlines for the annual emissions reports (April 10 and June 1). Accordingly, SCE proposes the following edits:

> If an operator fails to register a specified source by the ~~June 1 reporting deadline~~ ~~specified in section 95103(e)~~ **February 1 registration deadline specified in this section 95111(g)** 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 (SCE2)
>
> **Response:** The proposed text does reflect the language that the commenter refers to, which is shown in double underline in the 15-changes.
>
> With regard to the use of the term "operator" instead of "reporting entity" the commenter is correct that this is an error, and staff has corrected this typographical error in the final regulation. The existing text of section 95111(g) makes clear that the registration requirement applies to "reporting entities," not solely to "operators," and this has also been ARB's long-standing regulatory practice. As the commenter therefore recognizes, the sentence that the amendments would add to the general 95111(g) language, further specifying registration requirements, is not intended to alter the entities the section addresses. In context, the amendments can thus only be understood to apply to "reporting entities," like all other relevant requirements in the section, meaning that the term "operator" in the amendments is clearly a non-substantial error in a passage which on its face applies only to "reporting entities." Staff has therefore corrected this non-substantial error and will also issue guidance on this point as appropriate.
>
> Staff declines to make the change in timing for registering specified sources. The timing in section 95111(g) of February 1 refers to registering *anticipated* specified sources so that ARB can calculate the relevant emission factors prior to the reporting deadline. However, the change staff proposes which includes the June 1 deadline is a hard deadline after which specified sources could no longer be registered with ARB. This is needed to ensure that reporting entities register their specified sources and provide ARB sufficient time to calculate an emission factor related to the sources.

Meter Data Requirement

B-5. Comment: The "lesser of metered/scheduled" calculation

New language in 95111(e) clarifies the conditions when calculation of the lesser of metered generation and tagged or transmitted energy must be performed. This language explicitly excludes "imports from hydroelectric facilities for which an entity's share of metered output on an hourly basis is not established by power contract." However, it provides no guidance regarding imports from hydroelectric facilities, such as the Mid-Columbia resources where each entity's share is established by contract.

WPTF understands that CARB intends to release additional guidance on the lesser of analyses, and that this guidance will confirm previous CARB guidance provided in March 2013[19] that allocated generation under the Mid-C Hourly Coordination Agreement to be used in lieu of meter data for these resources. WPTF requests that this guidance be released as quickly as possible to avoid possible confusion regarding requirements for the Mid-C resources.

Lastly, WPTF offers a comment on the exemption of 'dynamically tagged power deliveries' from the requirement to perform the lesser of analysis. WPTF does not object to this exemption because it is currently consistent with RPS program requirements. However, we understand that the California Energy Commission[20] may revisit RPS program rules for dynamically transferred renewable energy because of the fact that the quantity of power transferred could exceed the quantity of renewable energy (and hence RECs) generated in each hour. We therefore urge CARB to monitor RPS program develops and modify the MRR as needed in the future to ensure consistency of the MRR's 'lesser of' analysis requirement with RPS program requirements. (WPTF2)

> **Response:** In regards to how Mid-C hydroelectric resources will be treated under this provision please see **Comment B-6** in Section IV. of this document related to the 45-day changes. Staff will continue to monitor the RPS program rules to determine if any changes implemented by the California Energy Commission would have an effect on MRR requirements.

B-6. Comment: Meter Data Retention

CARB should adopt the 15-Day Changes that moves the provisions regarding new data retention and verification requirement to Section 95111(b)(2)(E), as this avoids any potential confusion regarding the scope of the required data and its implications on use of the RPS adjustment. (NCPA2)

> **Response:** Thank you for your support.

[19] http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/epe_1pg.pdf
[20] See slide 14 at http://www.energy.ca.gov/portfolio/pou_rulemaking/2014-RPS-01/2014-07-11_workshop/2014-07-11_workshop_presentation.pdf

CAISO Sales Requirements

B-7. Multiple Comments: Reporting Sales in the CAISO are Properly Limited

The Proposed Amendments introduced a new requirement in Section 95111(a)(12)for non-IOU electrical distribution utilities to report sales into the CAISO. As originally proposed, the new requirement would have mandated reporting transactions beyond those needed to confirm compliance with section 95892(d)(5) of the Cap-and-Trade Regulation, and failed to define the scope of the transactions at issue. The 15-Day Changes add a definition for “electricity sold into the CAISO markets,” and clarify the scope of the reporting obligation. Specifically, the 15-Day Changes correctly (1) limit the scope of this new requirement to ensure that transactions that are “self scheduling” as defined in section 11.29 of the CAISO tariff are not included within the definition of “sales into the CAISO,” (2) create an exemption from the reporting requirement for POUs and Electrical Cooperatives that place all of their freely allocated allowances into their limited use holding accounts for consignment to auction, and (3) clarifies that the reporting applies to known sources and emission factors. These revisions, which reflect the feedback received from stakeholders, acknowledge the nuances of the CAISO markets relevant to defining “sales into the CAISO.” These changes also impose the same reporting requirements on all EDUs that place freely allocated allowances into their limited used holding accounts, and properly reflect the manner in which sales into the ISO are conducted. The 15-Day Changes that revise section 95111(a)(12) and add section 95102(a)(142) should be adopted. (MSR2)

Comment: Reporting ISO Sales Data

The 15-Day Changes add much needed clarifications to Section 95111(a)(12) and should be adopted. Proposed section 95111(a)(12) requires non-IOU electrical distribution utilities (EDUs) to report “sales in the CAISO.” The 15-Day Changes clarify this requirement by adding new Section 95102(142) to the MRR that defines “Electricity sold into the CAISO markets.” The proposed definition properly excludes transactions under “section 11.29(a)(iii) of the CAISO Fifth Replacement Tariff dated May 1, 2014.” This definition accurately reflects the fact that the CAISO tariff allows for scheduling of electricity that is not actually a sale, and therefore, not subject to the restrictions in section 95892(d)(5) of the Cap-and-Trade Regulation. CARB should adopt this new definition as part of the 15-Day Changes. NCPA is also supportive of the proposed revision to section 95111(a)(12) which address necessary modifications to clarify the source and emissions factor data that is to be included in the report, and which excludes “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,” from the scope of the reporting requirement. These clarifications avoid unnecessary reporting by the non-IOU EDUs, without limiting CARB’s access to the information the agency needs to confirm compliance with the relevant provisions of the Cap-and-Trade Regulation. NCPA also supports the inclusion of the definition for “electrical distribution utilities” found in the Cap-and-Trade Regulation to the MRR. (NCPA2)

Response: Thank you for your support and for working with staff to finalize the proposed regulatory language.

C. Reporting Requirements for Oil and Gas

C-1. Comment: Definition of Sub-Facility (Section 95102(a)(444)). WSPA requests ARB include additional clarifying language in the definition at Section 95102(a)(444).

Recommendation: Add the following language (in red text) to subdivision 444: "Sub-facility" for purposes of reporting data disaggregated pursuant to section 95156(a), means the geographic area, or areas, within a single township or within a group of contiguous or adjacent townships identified in the Public Land Survey System of the United States, where operations and equipment are located. The operator may disaggregate sub-facilities based on contiguous township areas to smaller sub-facilities according to similar operational, geological, or geographical characteristics. Operators may also designate one or more contiguous or adjacent properties under common ownership or common control as sub-facilities. Sub-facility disaggregation may be retained from year to year, or may be updated when some of the operations cease or equipment is reconfigured within the previously designated sub-facilities. Sub-facility disaggregation must be updated from previous reporting years if there are new operations or equipment that lies outside previous township boundaries. The Principal Meridian name, Township and Range designations, and the section numbers that apply to each sub-facility, must be identified in the operator's GHG Monitoring Plan required pursuant to section 95105(c). The operator must also describe in the GHG Monitoring Plan any operational, geological or geographical characteristics used to determine sub-facility boundaries. (WSPA3)

Response: Staff has evaluated the proposed text addition and has determined that added text is simply a clarification of requirements already inherent within the existing definition. Therefore, staff declines to make the edit, but will inform stakeholders through guidance that sub-facilities may also be designated as, "one or more contiguous or adjacent properties under common ownership or common control."

C-2. Comment: Population Count and Emission Factors (Section 95153(p)). WSPA supports ARB removing the actual component count requirement in Section 95153(p). As WSPA has stated previously, the EPA component count and emissions factor method is a valid approach for quantifying GHG emissions. (WSPA3)

Response: Thank you for your support.

C-3. Comment: Calculation of HHV (Sections 95156(a)(9), (10), 95156(b), 95156(d)). ARB proposes revising the method for calculating HHV on an annual basis using average HHV of quarterly gas samples as stated in Section 95153(y)(D). Currently, some operators conduct a monthly weighted calculation and aggregate it to the annual total. In these instances the resultant annual total may be more accurate than with the proposed method. Because using data collected on a monthly basis would be more accurate than on a quarterly basis, WSPA requests ARB allow operators the flexibility to use calculations that can be demonstrated to be more accurate than what is listed in the MRR regulation. (WSPA3)

> **Response:** The quarterly sampling frequency specified for HHV is a minimum requirement, and reporters may use more frequent sampling, if desired. Staff will clarify in guidance that the use of more frequent HHV sampling is acceptable for meeting the regulatory requirements identified in the comment.

D. Reporting Requirements for Legacy Contract Generators

No comments were received regarding reporting requirements for legacy contract generators in the 15-day comment period.

E. Product Data Reporting Requirements

Refinery Product Data Reporting Requirements

E-1. Multiple Comments: 1. The new issue related to reporting of CWB for ISOM units. This corrects an inconsistency with how the reactor feed is reported with Solomon surveys. Tesoro recommends the following language:

95113 (l)(5)(A) Should read:
Reporting of CWB Throughputs Functions. The operator must report the annual throughput for each CWB unit listed in Table 1 of this section, using the appropriate units listed in column 3 of Table 1 of this section. With the exception of C4 Isomer Production and C5/C6 Isomer production, reported throughputs based on feed must include only fresh feed and exclude recycled streams. Throughputs for C4 Isomer Production and C5/C6 Isomer production should be based on reactor feed including recycle. (TESORO1)

Comment: <u>Reporting of CWB Throughputs.</u> ARB proposes to change Section 95113(l)(5)(A) to require operators to report only fresh feed and to exclude recycled streams as part of the CWB throughput reporting requirement. WSPA is concerned with ARB making this change at the tail end of the process in a 15-day comment period instead of allowing a full 45-day comment period. Making this change so late in the process also raises questions concerning ARB's expectations as to how operators should be collecting and tracking this information, including levels of accuracy for reporting both fresh and recycled feeds. For example, Solomon acknowledges that for ISOMER units, reported throughputs already include both fresh and recycled feeds.

WSPA recommends ARB delete its proposed language changes in section 95113(l)(5)(A) and instead work with WSPA and its members through a formal workshop process that will provide operators a meaningful opportunity to comment on what is both necessary and technically feasible to address ARB's concern with recycled and fresh feed reporting. (WSPA3)

> **Response:** The requirement to report only fresh feed and to exclude recycled streams when reporting CWB throughputs is needed in the regulation to ensure reporting consistency among all refineries. The need to exclude recycled streams is currently clarified in ARB's CWB reporting guidance documents, but staff believes that the regulation itself should be clear on this issue. No supporting evidence that recycled feeds should be included when reporting ISOMER unit CWB throughputs has been provided to ARB staff. Staff could consider exceptions to the requirement in a separate rulemaking to include only fresh feed streams in CWB throughputs for certain units if provided documented evidence that shows recycled streams should be included for those units.
>
> The timing of this regulation change does not impact expectations about how CWB throughput data are collected or the accuracy levels of those data. The requirements for data collection and measurement accuracy are in section 95103(k) of the regulation.

E-2. Comment: <u>Use of Best Available Method (BAM) for Reporting 2014 Primary Refinery Product and Calcined Coke Data (</u>Section 95103(h)(1)<u>).</u> WSPA supports ARB extending the use of BAM for primary refinery products and calcined coke data reporting for the 2014 reporting year. WSPA requests ARB clarify that BAM, as defined in the MRR regulation, are methods based on criteria that is reasonably feasible for facility fuel use or other facility process data in conjunction with ARB-provided emission factors, and other industry standard methods for calculating GHG emissions. Use of BAM methods utilizing data collected from CWB meters should be deemed sufficient for demonstrating the <u>+</u>5% accuracy requirement, and operators should not be required to provide additional data or information beyond that which is reasonable or feasible and available.

> **Response:** Thank you for your support for extending the use of BAM for reporting 2014 primary refinery product and calcined coke production. ARB staff generally concurs with the commenter's interpretation that BAM, as it relates to primary refinery product and calcined coke production, are methods that use facility fuel use, other facility process data, or other industry standard methods to determine the desired value. Instances where BAM for determining primary refinery product or calcined coke production are solely based on CWB meter data should be very limited. If CWB meters are the only source of data for determining primary refinery product or calcined coke production, then the ±5% accuracy requirement of those meters should be demonstrated as prescribed in section 95013(k) of MRR.
>
> Staff generally agrees that operators are not required to provide additional data or information beyond that which is reasonable or feasible and available while BAM provisions are in effect.

E-3. Comment: Additional Reporting Requirements. Several additional reporting requirements proposed by ARB are unrelated to compliance with the Cap and Trade program and should be removed from the regulation. While it is reasonable for ARB to address policy questions from its Board, WSPA continues to object to ARB's use of the MRR regulation as the mechanism to obtain such information because it has failed to demonstrate a regulatory need for the information. The proposed requirements are unrelated to allocation of emission allowances or assessment of fees necessary to cover AB 32 program costs. Moreover, using the MRR regulation as the reporting mechanism for information not required for compliance needlessly and unjustifiably compounds the burden associated with the information request by virtue of the myriad data collection, verification and reporting requirements embedded in the MRR regulation.
The following data requirements ***should be removed*** from the MRR regulation:

- Primary refinery products (section 95113(l)(1))
- By-product hydrogen gas (section 95114(j)); if by-product hydrogen reporting is not removed, then ARB should allow BAM for this reporting since it is not necessary for CWB.
- Sampling and reporting of atomic hydrogen content in hydrogen production feed gas (section 95114(e)(1))
- Energy Intensity Index (95113(l)(4))

WSPA previously indicated its willingness to develop with ARB a non-regulatory mechanism for generating the data it seeks, such as a one-time survey, provided there is a clearly defined purpose and the intended use of the data is disclosed to the reporting entities. We anticipate further discussion with ARB to explore alternative approaches that can accomplish the intended purpose without building additional complexity, administrative burden and compliance costs into the MRR regulation.

It is imperative that ARB sunset reporting requirements for data which are no longer needed to ensure compliance. (WSPA3)

> **Response:** This comment is beyond the scope of the 15-day amendments. Staff is open to working with affected stakeholders to identify unnecessary reporting requirements in future rulemakings. The listed data elements are used in support of ARB's annual inventory efforts (by-product and atomic hydrogen), and to evaluate benchmarking and allocation methods (primary refinery products and energy intensity index). For more information please see the response to **Comment E-1** in Section IV of this document related to the 45-day changes.

Hydrogen Product Data Reporting Requirements

E-4. Comment: 2. 95103 (h)(4): Tesoro does not agree with the elimination of best available methods for measuring by-product hydrogen. The by-product hydrogen is not currently incorporated into the CWB calculation and resultant allocations so it should not be subjected to the more stringent accuracy requirements; and therefore, subject to increased enforcement risk. Please retain the flexibility to comply with BAM for these meters consistent with this provision in the current regulation. (TESORO1)

> **Response:** Section 95103(h) of the regulation is used to identify new reporting requirements that may take additional time for reporters to fully implement due to the need for additional data collection or monitoring, and allow reporters to use best available methods for reporting the new data in the first year of reporting. Reporting requirements for by-product hydrogen became effective on January 1, 2014, and best available methods were allowed for 2013 data reported in 2014. Because reporting by product hydrogen is not a new requirement for 2014 data, best available methods is not needed for data reported in 2015.

F. Fuel Supplier Reporting Requirements

F-1. Comment: <u>Suppliers of Transportation Fuels and Renewable Diesel.</u> As stated in our September 15, 2014 letter, ARB is proposing a new requirement to report volumes of renewable diesel supplied. WSPA feels compelled to reiterate the point that renewable diesel can be blended to diesel product both at the refinery and at the terminal, and therefore Reporting (e-GGRT) forms should be modified to allow for reporting volumes from either the terminal or the refinery in a manner that prevents the possibility of double-reporting the same volumes of fuel and a doubling of one's compliance obligation under Cap-and-Trade.

Additionally, it is very likely that significant renewable fuel blending may occur upstream of terminal rack locations, particularly for renewable diesel which is much more likely to be blended at refineries. Because blend percentages will vary depending on operational circumstances and product availability, it will likely be difficult to accurately track the precise movement of those renewable fuel volumes from the refinery (or bulk blending facility) to the point where the blended product is dispensed into a truck at the terminal rack.

Therefore, WSPA recommends ARB add a paragraph to the § 95121 reporting procedures that would allow a reporting party to report the total renewable fuel blended upstream of the terminal rack and subtract it from the total blended product delivered to market.

> ***Recommendation:*** WSPA recommends the following paragraph be added to follow § 95121(d)(1-4): <u>"(5) Refiners who blend renewable fuels at a refinery or bulk facility and displace blendstock or distillate fuel oil may report the total volume of renewable fuel blended at the refinery or bulk facility and subtract the displaced volume from the blendstock and distillate fuel oil totals reported under paragraphs (1) through (4), provided that it can be demonstrated that the renewable fuel volume was not reported under paragraphs (1) through (4) by the refiner or any other party."</u>

As an illustration of how this might work, a reporting party could blend renewable diesel at a refinery and report the total renewable diesel volume blended for the year. That party would then calculate the total CARB diesel volume delivered to market per § 95121(d)(1-4) and subtract the renewable diesel volume.

The remainder would be reported as CARB diesel delivered. Following this reporting, the reporting party's verification auditors would confirm that the reporting party ensured the credit for the renewable diesel volume was not claimed elsewhere, either through clear product transfer documents or contractual agreements. (WSPA3)

> **Response:** This comment is outside the scope of the 15-day changes. Please refer to the response to **Comment F-2** in Section IV. of this document for more information.

G. MRR General Comments

G-1. Comment: Implementation Period and Other Technical Issues Remain Unanswered. WSPA is disappointed that ARB chose not to incorporate several of the recommendations in our September 15, 2014 comment letter into the proposed 15-day MRR language (See attached). Our recommended changes and requests for clarification in sections 95103(h)(4), (l) and (m)(1) are intended to facilitate compliance with the regulation by promoting consistent interpretation of MRR requirements and additional, reasonable flexibility for regulated entities. We respectfully request that ARB reconsider the specific requests and recommendations in our prior comment letter. (WSPA3)

> **Response:** Staff did not to make the changes identified, as described in responses to 45-day comments. For specific explanations, see the following responses in Section IV. of this document related to 45-day comments: **Comment E-3**, regarding section 95103(h)(4); response to **Comment G-4**, regarding section 95103(l); and response to **Comment G-6** regarding section 95103(m)(1).

G-2. Comment: Need for Lead Time to Implement MRR Changes. We especially note the need for lead time for facilities to implement changes and collect data that is expected to be required as of January 1, 2015. WSPA noted the unique challenge posed by passage of a regulation so close to its implementation date by noting both in writing and in oral testimony, that data collected in 2014 and reported in 2015, would not be subject to these new requirements. With respect to data collected in 2015, WSPA testimony and Board response noted that a phase-in period, where best available methods and technology currently employed should be allowed in 2015 as companies phase-in newly required practices. In many cases, technology must be acquired and adopted, labor resources must be on-boarded, and training must be performed to adequately and competently implement the requirements of these rules. A minimum 1 year implementation period should follow all adopted rules. Failure to address these issues could undermine the integrity of the data derived from the regulation and frustrate ARB's efforts to accurately assess progress toward meeting statutory emission reduction goals. (WSPA3)

> **Response:** Please see response to 45-day **Comment G-2** in Section IV. of this document.

G-3. Multiple Comments: The Southern California Public Power Authority (SCPPA) is pleased to offer its support for the modifications to the proposed amendments to the Mandatory Reporting Regulation released on October 2, 2014.

SCPPA is a joint powers authority consisting of eleven municipal utilities and one irrigation district. SCPPA members deliver electricity to approximately two million customers over an area of 7,000 square miles, with a total population of 4.8 million people. SCPPA Members include the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, and the Imperial Irrigation District.

We particularly appreciate the time and consideration ARB staff afforded to SCPPA Members and other Publicly Owned Utility stakeholders over the course of the past year, to listen to and address our concerns with the proposed amendments, and to share draft revisions for stakeholder comment.

SCPPA would like to take this opportunity to sincerely thank the following ARB staff for their willingness to meet and work with our Members: Brieanne Aguila, Richard Bode, Mary Jane Coombs, Bill Knox, Wade McCartney, Rajinder Sahota, Craig Segall, and Holly Stout. We believe that the 15-day language reflects an earnest and cooperative rulemaking effort that resolves our concerns. (SCPPA2)

Comment: As more fully explained below, M-S-R Public Power Agency (M-S-R)[21] supports the 15-Day Changes that (1) allows the continued use of the transmission loss factor of 1.0 if certain criteria are met; (2) modifies the proposed reporting requirements for electrical distribution utility sales into the CAISO, and (3) creates a definition for "sales into the CAISO" that accurately captures the intent of the regulation. The revised regulatory language addresses concerns raised by stakeholders in written comments on the Proposed Amendments and before the Board during the September 18 meeting, and M-S-R appreciates CARB's responsiveness to those concerns. As discussed herein, the proposed revisions set forth in the 15-Day Changes should be approved.

The July 29 Proposed Amendments included several changes to the Mandatory Reporting Regulation that M-S-R found unworkable in the context of the normal operations of its electric utility members. M-S-R and other stakeholders explained these problems to CARB Staff.

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[21] Created in 1980, the M-S-R Public Power Agency is a public agency formed by the Modesto Irrigation District, the City of Santa Clara, and the City of Redding. M-S-R is authorized to acquire, construct, maintain, and operate facilities for the generation and transmission of electric power and to enter into contractual agreements for the benefit of any of its members.

M-S-R appreciates that the 15-Day Changes acknowledge these stakeholder concerns, and values the time the Staff took to work with stakeholders on crafting feasible solutions that both address stakeholder comments and further CARB's objective of ensuring accurate and complete reporting of GHG emissions. As such, M-S-R urges that the 15-Day Changes to the Proposed Amendments to the MRR discussed herein be adopted. (MSR2)

Comment: The proposed 15-Day Changes reflect the joint efforts of CARB staff and stakeholders to draft regulatory language that addresses both CARB's stated objectives in revising the MRR and stakeholder concerns. NCPA appreciates Staff's responsiveness to stakeholder comments and urges CARB to approve the 15-Day Changes addressed herein. The changes also reflect the direction provided by the Board in Resolution 14-32, and should be adopted. (NCPA2)

Comment: CCEEB supports the proposed amendments to the "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" related to the provisions regarding corporate associations. We appreciate the time and effort ARB staff spent on working with our members to cooperatively achieve supportable harmonization of data reporting requirements. CCEEB supports the positions of our members with whom your staff has been working diligently to find practical, feasible solutions on the remaining outstanding issues regarding amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and, the Cost of Implementation Fee Regulation. We ask for that work to continue and hope we can continue to work with ARB staff to make the necessary changes that will ensure these regulations are both technologically sound and economically feasible. (CCEEB2)

Comment: WSPA has long-supported market-based approaches to improve air quality and the environment. As you know, WSPA has been an active participant in workshops and have submitted numerous comments on behalf of our membership identifying issues and potential remedies that could be beneficial as the Air Resources Board (ARB) implements the Cap-and-Trade program. With regard to our September 15, 2014 comments on the need for various process improvements, WSPA appreciates ARB's willingness to meet with us on a periodic basis to discuss current issues and to identify emerging issues that may require further guidance or regulatory modification. We are confident that this dialogue will help avoid future implementation and compliance problems, and in so doing will benefit both parties. We thank ARB management and staff for promptly initiating this process and look forward to our first meeting in early November. (WSPA3)

Response: Thank you for your support.

G-4. Comment: WSPA notes that with the successive iterations of the C/T and MRR regulations, the regulatory language has become increasingly convoluted such that it may be interpreted in a number of ways – some that run the risk of being contrary to ARB's intent. We are concerned that the complex and, indeed complicated, regulatory language will lead to misinterpretation of C/T and MRR program requirements and expose even the most diligent regulated entities to inadvertent non-compliance. We understand that some of these complications are borne out of the need to meet administrative standards for 15 day rulemakings. In order to address the ongoing need for clarity, WSPA proposes that ARB solicit input from interested stakeholders on recommendations to clean-up and simplify C/T and MRR regulatory language in the next rulemakings. This effort could be part of the 45-day regulatory package that ARB expects to introduce in early 2015. (WSPA3)

> **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 in early 2014 on areas where regulatory clarification was needed and on concepts for potential regulatory amendments. In February through May of 2014, staff released guidance and gave presentations to reporters, which included the majority of the clarifications that were made in proposed amendments. The proposed amendments do not introduce any new requirements, but serve to codify guidance given by staff earlier in the year. In addition, staff held a public workshop on June 5, 2014 to discuss draft regulatory changes released prior to the workshop. Staff crafted the proposed amendments submitted in the 45-day regulation based on stakeholder feedback as a result of that workshop and extensive stakeholder outreach. 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. 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.

H. Cost of Implementation Fee Regulation Comments

H-1. Comment: WSPA appreciates ARB's proposed changes in the 15-day language in response to our comments, including changes to section 95201(c) to exclude biodiesel and renewable diesel fuels consistent with the MRR regulation, removal of the term "catalyst coke" from the definition of petroleum coke in section 95202(a)(111) and the clarification in section 95203(d) that fuel emission factors will be calculated using an arithmetic average of fuel grades from column C of 40 CFR 98 Table MM-1.

WSPA notes that the proposed changes in section 95204(i), intended to align the records retention provisions in the fee regulation with those in the MRR, only corrected one of the inconsistencies. We request that ARB also strike the requirement to maintain records in California to achieve conformity with the MRR regulation:

> ***Recommendation*:** Modify this section to read: "*Entities subject to this subarticle must maintain copies of the information reported pursuant to the applicable sections of the Mandatory Reporting Regulation*~~. Records must be kept at a location within the State of California for five years~~."

WSPA, representing companies that actually implement the emission reduction requirements planned by ARB, appreciates the opportunity to continue these discussions. We look forward to the addressing issues that remain unresolved in future rulemaking. (WSPA3)

> **Response:** These comments address the Cost of Implementation Fee Regulation. These comments are addressed in the 2014 COI Fee Regulation Final Statement of Reasons.

I. Cap-and-Trade Regulation Comments

I-1. Comment: Corporate Disclosure Requirements. WSPA supports ARB's ongoing work with industry stakeholders to streamline corporate association disclosure requirements. We are particularly appreciative of ARB's action to incorporate in the regulation language from its July 29, 2014 guidance allowing companies to substitute specified information filed with the Securities and Exchange Commission (in particular the Form 10-K list of subsidiaries), the Federal Energy Regulatory Commission and the Commodities and Futures Trading Commission, for the disclosure requirements that otherwise apply to unregistered entities.

ARB's decision to incorporate WSPA's proposed changes to section 95830 (f)(1) will further reduce the administrative burden associated with updating registration information for consultants and advisors. However, we would like confirmation that the proposed regulatory language in this 15-day package continues to exempt entities from reporting indirect corporate associations not registered in the cap and trade program as noted in Guidance issued in July of this year.

As ARB is aware, the industry coalition proposal, dated August 22, 2014, contains a number of important changes to the Cap and Trade regulation which ARB counsel determined are not eligible for inclusion in this 15-day package. One such issue is the regulatory investigation disclosure requirements that must be included in an auction application attestation (section 95912). WSPA appreciates ARB's issuance of guidance on October 10 in response to these concerns by allowing use of best available data for the 5- to 10- year old investigation and to use best available data for corporate affiliates. However, we remain concerned about the overly broad and extremely burdensome nature of the attestation requirement relating to such investigations and the inadequate notice given to registered companies. We also remain concerned about ARB's issuance of guidance on this matter just a few days (10) prior to the deadline for participation in the upcoming auction.

Given the very recent release of this guidance WSPA has not had time to study it in any detail. We urge ARB to take the next step to revise the regulations rather than continue to rely on guidance for the reasons stated above. We understand that it is ARB's position that any such change lies beyond the current scope of rulemaking and ARB will initiate a new Cap and Trade rulemaking in the very near future to address this issue and the other remaining elements of the industry coalition proposal.

We are optimistic that the collaborative dialogue which produced the above noted amendments will continue to bear fruit in the form of further amendments toward a more workable and effective Cap and Trade regulation. We look forward to working with you to incorporate the coalition proposals into new regulatory language in advance of a formal Notice of Proposed Rulemaking.

<u>Proposed 15-Day Amendments to the California ODS Offset Protocol.</u> WSPA opposes the proposed change in the ODS Offset Protocol Section 3.8(b) bolded/underlined below, which extends regulatory compliance requirements beyond the offset project to the entire ODS destruction facility during the time ODS destruction occurs (and thus expands the buyer's liability beyond that directly associated with the offset project to any activity performed at the ODS destruction facility).

3.8. Regulatory Compliance

(a) An offset project must meet the regulatory compliance requirements set forth in section 95973(b) of the Regulation.
(b) The regulatory compliance requirements for a project apply to the collection, recovery, storage, transportation, mixing, and destruction of ODS, including disposal of the associated post-destruction waste products. ***<u>The regulatory compliance requirements extend to the destruction facility during the time ODS destruction occurs.</u>***

This proposed change is in direct conflict with ARB's existing rules and policies governing all offsets as well as policies embedded in other project protocols. For example, in April 2014, ARB adopted amendments to Section 95973(b) (Requirements for Offset Projects Using ARB Compliance Offset Protocols) by adding new language in bold below:

Section 95973(b) In addition, an offset project must also fulfill all local, regional, and national environmental and health and safety laws and regulations that apply based on the offset project location ***and that directly apply to the offset project***, including as specified in a Compliance Offset Protocol. The project is out of regulatory compliance if the project activities were subject to enforcement action by a regulatory oversight body during the Reporting Period. An offset project is not eligible to receive ARB or registry offset credits for GHG reductions or GHG removal enhancements for the entire Reporting Period ***if the offset project is not in compliance with regulatory requirements directly applicable to the offset project during the Reporting Period.***

The proposed change to the ODS protocol is in conflict with this recent change. The existing regulation is clear that changes that might give rise to an invalidation event at an ODS project should be tied to the project itself, and not the facility more broadly.

Imposing a broad facility-related regulatory compliance clause on ODS projects would add additional liability burden to ODS destruction offsets, and in so doing, could limit the amount of ODS that gets destroyed, disincentivizing an excellent technology for reducing High Global Warming Pollutants. The Cap and Trade program and the covered entities need consistent approaches and policies that provide clear equitable rules for all offset projects.

Holding Limits Issues Still Unresolved. While we recognize that changes to holding limit requirements is beyond the scope of this 15-day package, the expected inclusion of fuels under the cap will pose even more challenges to market. Thus the need for changes to the current holding limit requirements is even more urgent. WSPA reiterates the importance of accommodating greater flexibility for holding and purchase limits in the next round of amendments to the Cap and Trade regulation. As we noted in our September 15, 2014 comments (as well as in 2011 and 2013), the very low holding and purchase limits in the current regulation constrain the marketplace, limiting participants' flexibility to comply at the lowest incremental cost, and disproportionately impact entities with large compliance obligations.

WSPA urges that ARB address this issue in early 2015. A blueprint for regulatory changes has already been developed by the Emissions Market Assessment Committee (EMAC). The key EMAC recommendations address scaling of holding and purchase limits to reflect the size of the regulated entity's compliance obligation, and provide increased flexibility and control for the regulated entity with respect to management of compliance accounts. (WSPA3)

> **Response:** These comments address the Cap-and-Trade Regulation. These comments are addressed in the 2014 Cap-and-Trade Regulation Final Statement of Reasons.

VI. PEER REVIEW

Health and Safety Code section 57004 sets forth the requirements of peer review of identified portions of rulemakings proposed by entities within the California Environmental Protection Agency, including ARB. Specifically, the scientific basis or scientific portion of a proposed rule may be subject to this peer review process. Here, ARB determined that the rulemaking at issue does not contain scientific basis or a scientific portion subject to peer review, and thus no peer review as set for in section 57004 was or needed to be performed.